KOLESAR BUCHANAN & ASSOCIATES LIMITED

STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 24-070

REQUEST FOR CHANGE IN RATES

PRINCIPLE REPORT

Mr. Mark B. Kolesar

On behalf of Public Service Company of New Hampshire

d/b/a Eversource Energy

June 10, 2024

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I. Introduction

My name is Mark Kolesar. I am the Managing Principal at Kolesar Buchanan & Associates Ltd. I have been retained by Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource or the Company) to provide advice and expert opinion evidence with respect to the Company's performance-based regulation application before the New Hampshire Public Utilities Commission ("PUC" or "Commission") in Docket No. DE 24-070.

The following is my expert opinion evidence on the Company's application for approval of a Performance Based Regulation ("PBR") Plan, submitted on June 11, 2024. The footnotes are an integral part of this submission and should be read in full.

II. Qualifications

I have over 30 years of experience in the regulated utilities sector, having worked in the areas of regulation and public policy, external relations, marketing, strategy and business development, and mergers and acquisitions. This includes over 20 years of corporate experience in the telecom sector, where I was Vice President, Economic Affairs at TELUS Corporation. During this time, I was engaged in the adoption of PBR in the telecommunications sector. More recently, with respect to this proceeding, I concluded my tenure with the Alberta Utilities Commission (AUC) in July 2020, where I was a commission member for twelve years, including six years as Vice Chair and two years as Chair of the commission. During my time at the AUC, I issued over 1,400 decisions, and I was instrumental in the adoption of PBR in Alberta. During my AUC tenure, I adjudicated numerous PBR applications for two gas distribution utilities, four electric distribution utilities and one electric transmission utility.

Since leaving the AUC in July of 2020, I have been a researcher, author and consultant in utility regulation and policy development, and a frequent participant in webinars and conferences in Canada, and the U.S. My current areas of research include incentive regulation, the theory and practice of PBR, community energy projects, the integration of distributed energy resources into the grid, the future of utility rate design, utility business models and regulatory renewal in response to emerging utility industry dynamics. I have published articles in academic journals, most recently in The Electricity Journal,[1] and I have

[1] Victor Glass, Mark Kolesar, Timothy Tardiff, Bruce Williamson, Provider of last resort in emerging electricity markets: Lessons from telecommunications deregulation, The Electricity Journal, Volume 35, Issue 1,2022, 107064, ISSN 1040-6190.

contributed to books on Energy Communities[2] and The Future of Decentralized Electricity Distribution Networks,[3] both published by Elsevier.

I am a frequently invited speaker at conferences, having participated in Electricity Canada's 2022 Regulatory Forum, Rutgers Center for Research in Regulated Industries 40th Annual Advanced Workshop in Regulation and Competition in Atlantic City New Jersey (June 2022) and 33rd Annual Advanced Workshop in Regulation and Competition in Monterey California (June 2022), the EUCI 2022 Canadian Rate Design Conference (September 2022) and EUCI Performance-Based Regulation for Utilities and Stakeholders (May 2023), and more recently Rutgers Center for Research in Regulated Industries 34th Annual Advanced Workshop in Regulation and Competition in Monterey California (June 2023) and GridFwd2023, Stevensen, Washington (October 2023).

I have advised several utilities and regulators on matters related to PBR and incentive regulation. I have an Honors Degree in Philosophy and an MBA in Managerial Economics and Finance. My detailed curriculum vitae is provided with this testimony as Exhibit ES-AR/MK-2.

My experience at the AUC, as well as my education and other experience and qualifications, are directly related to the matters I have been asked to opine on.

III. What is Performance Based Regulation

The term "performance-based regulation" generally refers to rate regulation regimes that provide incentives to the regulated utility to increase efficiency while reducing regulatory costs. As explained in greater detail in *An Overview of Performance Based Regulation And its Application* (Exhibit ES-AR/MK-3), PBR substitutes the setting of rates based on a company's cost of service with the establishment of capped revenues or rates, over a stay-out period that typically exceeds the periodicity of a cost-of-service regulation (COSR).

Traditional COSR regimes are "cost-plus" forms of regulation that derive a firm's prices from its underlying costs, including a rate of return. As a result, productive efficiencies tend to be lower under cost-of-service regulation because a utility under COSR is required to lower revenues if it lowers its costs, whereas an increase in prudently incurred costs would normally result in higher revenues and potentially higher returns. This is not to say that cost-of-service regulation cannot provide incentives for reducing costs and increasing productive efficiency. For example, where rate case proceedings are infrequent due to regulatory lag, a firm under COSR has an incentive to reduce costs between rate cases

[2] Löbbe Sabine, et al. "Energy Communities: a North American Perspective." Energy Communities: Customer-Centered, Market-Driven, Welfare-Enhancing?, Academic Press, Amsterdam, 2022.

[3] Fereidoon Sioshansi "The Future of Decentralized Electricity Distribution Networks" 1st Edition, Academic Press, Amsterdam, 2023.

because rates are fixed, and it retains the resulting increase in return until the next rate case. The longer the time between rate cases, the greater the efficiency incentive effects. However, a firm under COSR that is achieving efficiency gains and higher returns comes under pressure to return those gains to customers on a near-term basis by resetting rates in a traditional cost-of-service rate case, discouraging the firm from taking steps that would reduce costs over a multi-year time frame.

Unlike COSR, PBR in the form proposed by the Company, promotes increased efficiency beyond what might be expected under COSR, because the Company's actual rates will change during the term of the PBR plan at a rate that is designed to motivate the utility to be an efficient cost-performer. The fundamental objective of this approach is to provide a level of revenue during the PBR term sufficient to support operations and infrastructure investment in the system, while still incentivizing the utility to efficiently manage its cost structure by requiring it to "stretch" in order to maintain its financial integrity over a multi-year time frame. The result is intended to produce lower overall rates for customers relative to what they would otherwise experience, and to lower the rate increases otherwise required at the next base rates proceeding as compared to traditional COSR.

Under the form of PBR proposed by Eversource, the Company's revenue requirement is regulated annually by an indexing formula. If the Company can find ways to satisfy its obligation to provide service at the level of quality mandated by the Commission, while reducing costs, it will keep some or all of the cost savings as additional profit until the next time rates are re-based in a base-rate proceeding. As a result, under PBR, customers are likely to benefit from lower rates than would otherwise be the case under COSR, as well as increased rate stability and predictability relative to what would be expected under COSR.

The potential for superior efficiency incentives and regulatory cost savings depends, in part, on the duration of the PBR plan. In general, the longer the duration of the PBR plan, the greater the incentive effects because the utility has a longer period to seek out efficiency gains, some of which may not be fully realized over a shorter period, and the Company can keep realized returns for a longer period, subject to any consumer protections (for example, an Earnings Sharing Mechanism, as described below). Typically, PBR plans can last anywhere from as little as two years to as long as ten years. Because PBR plans facilitate a longer stay-out period between base-rate proceedings, PBR can help to reduce the high regulatory and administrative costs usually associated with more frequent base rate cases for both the regulator and the Company, or the administrative costs that come with annual capital cost recovery mechanisms that may be instituted in other alternative forms of regulation.

In addition to a PBR plan's duration, a key determinant of the strength of the incentives is whether the plan incorporates an earnings-sharing mechanism. A PBR plan without earnings sharing provides greater incentive effects than plans with earnings sharing, which is effectively a tax on the incremental profits subject to sharing. However, as explained further in *An Overview of Performance Based Regulation And its Application* (Exhibit ES-AR/MK-3), earnings sharing mechanisms can serve as a vehicle to share benefits more readily with customers and, depending on its construction, an earnings sharing mechanism can also more equitably share risk.

IV. PBR Will Benefit Customers in New Hampshire

The current regulatory regime in New Hampshire consists of base distribution rate applications with annual step adjustments intended to address earnings attrition between rate cases to allow for an extended stay-out period that incentivizes utilities to control costs. For Eversource, the current regulatory regime was established by virtue of the Settlement Agreement reached in 2020 in Docket No. 19-057.

In the absence of a settlement agreement, the New Hampshire regulatory regime approves a going-forward revenue requirement based on an historical test year. Known and measurable adjustments are calculated based on an historical test year and the rate base is adjusted for prudent capital additions since the last base rates case to calculate a rate-year revenue requirement. Base rates to recover the approved revenue requirement are then approved for the utility for the subsequent year.

The periodic step adjustment regime subsequently approves periodic rate increases to recover the incremental revenue requirement associated with approved capital additions, up to the level of an annual revenue cap established for the step adjustment. In the case of Eversource, the Docket No. 19-057 Settlement Agreement established three step adjustments, with the first step implemented concurrent with the increase in base rates to recover no more than $11 million in revenue requirement associated with projects in service in calendar year 2019, excluding new business/growth-related projects; the second step commencing August 1, 2021 to recover the revenue requirement of $11 million for annual projects and programs closed to plant in calendar year 2020, excluding new business/growth-related projects; and the third step commencing August 1, 2022 to recover the revenue requirement $8.9 million for annual projects and programs closed to plant in calendar year 2021, excluding new business/growth-related projects. [4]

When accompanied by a settlement agreement, the current regulatory regime in New Hampshire exhibits some of the characteristics of a PBR plan in that the regime allows for a longer stay-out period between base rates proceedings. In the case of Eversource, the Settlement Agreement reached in Docket No. 19-057 stipulated that the Company could not rely on a test-year period ending any sooner than December 31, 2022, effectively

[4] Step 1 adjustment effective January 1, 2021 (Order No. 26,439 on December 23, 2020); Step 2 adjustment effective August 1, 2021 (Order No. 26,504 on July 30, 2021); Step 3 adjustment effective November 1, 2022 (Order No. 26,709 on October 20, 2022)

achieving a two-year stay-out from the time that settlement agreement was approved, with rates effective January 1, 2021. The longer stay-out period encourages the Company to achieve efficiency gains in O&M expenses because Eversource retains any resulting higher returns for the duration of the stay-out period. Eversource has achieved some efficiency gains and held distribution operation and maintenance costs relatively constant overall, excluding storm costs, since 2017 under the current regime.[5] The regime also results in greater rate stability and more gradual rate increases over the longer stay-out period because the costs associated with capital additions are more gradually recovered in rates as step increases, rather than being reflected in a single rate increase following a subsequent base rates proceeding. The current regime is, nonetheless, fundamentally a cost-plus form of regulation that derives prices directly from underlying costs with inherently weaker efficiency incentives than provided by a well-designed PBR plan.

A well-designed PBR plan will provide the opportunity for a longer stay-out period (i.e., longer than 2 years), resulting in stronger efficiency incentives and a reduced regulatory burden for both the Commission and the Company, all of which will benefit customers. A well-designed PBR plan will also share the benefits of increased efficiencies more readily with customers, result in rate increases that are likely lower than under the current regime, will provide the Company with more financial flexibility, and better equip it to respond to changing industry dynamics.

A. PBR will provide a longer stay-out period.

Under the current regime, as under PBR, when revenue is insufficient to recover the cost of providing service, the Company is incentivized to find efficiencies to offset the shortfall. When the shortfall cannot be made up sufficiently to avoid earnings attrition, the Company is compelled to return to the Commission with an application to increase base rates. Although the step adjustments associated with incremental net capital additions assist in extending the stay-out period, the portion of rates associated with the costs of operations and maintenance remain unchanged until base rates are adjusted. Hence, if O&M expenses become too far out of alignment with base rates, due to inflation, market dynamics, or other forces,[6] the stay-out period will likely end.

Despite holding the line on O&M expenses, Eversource has experienced earnings attrition. In addition, under the current regime, the step adjustments are insufficient, by their design, as they are structured to provide less revenue than necessary to support the costs associated with the capital underlying the step adjustments. This is because, through a

[5] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton.

[6] For example, as utilities reinforce the grid to support the obligation to provide more grid-supplied energy in response to strategic electrification polices, the expected revenue from increased load may be offset by customer self-supply and storage alternatives. In this circumstance these countervailing forces may negatively affect utility earnings.

settlement agreement, the step adjustments are: (1) capped at negotiated amounts; (2) exclude certain categories of plant required to provide service, including a fair return, (3) have effective rate adjustment dates that go into effect a full eight months after the year ends; and (4) are subject to litigation annually before the PUC, often resulting in regulatory concessions by Eversource to implement revenues that are lower than would be justified based on the level of capital investment eligible for the step.[7] As a result, this framework provides incremental revenues that are less than the costs associated with the step-eligible capital additions, resulting in earnings attrition.

Under a well-designed PBR plan, a utility agrees to an extended stay-out period, usually not less than five years, during which rates are adjusted annually according to an indexing formula that accounts for O&M inflation and the costs associated with net capital additions, both of which are tempered by a productivity offset. This promotes increased efficiency, provides for timely recovery of the associated revenue requirement that is tailored to better align with net capital additions, and reduces the likelihood of earnings attrition; all of which allows for the longer stay-out period.

B. Regulatory burden will be lower under PBR.

Because the time between base rates proceedings can be significantly longer under PBR, the frequency of base rates proceedings is reduced as are the associated regulator and utility costs; costs that are borne ultimately by customers.

In addition, under a well-designed PBR plan, rates are adjusted annually according to a formula, thereby reducing the number and complexity of annual proceedings. Generally, all that is required is an annual proceeding to review the application of the PBR formula and approve the resulting change in the level of rates, all of which is straightforward and usually uncontroversial, once the PBR framework is established.

The current regulatory regime requires an annual proceeding to compare actual changes in net plant to the previously forecasted increases and to determine the prudence of the net capital additions to calculate the step adjustment in rates required to recover the costs associated with those investments. Annual step adjustment proceedings require an in-depth regulatory review of capital additions.[8] No such proceeding is required under a well-designed PBR plan because net capital additions are governed by the PBR formula.

[7] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton.

[8] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton.

C. PBR will promote lower customer rates.

Under PBR, in the form proposed by the Company, a regulated profit seeking utility will be more strongly compelled to seek productivity improvements because the utility is able to retain at least some of the return above the allowed return over a longer stay-out period, and because the cap on revenues assumes a minimum level of productivity that the utility is required to achieve to earn its allowed return. In most circumstances, the sharing with customers of the productivity improvements anticipated in a PBR plan is immediately reflected in a consumer dividend that requires the utility to share the "first cut" of the productivity gains with its customers in rates, <u>even if the minimum level of productivity is not achieved</u>. The cap on revenues limits the extent to which the utility can increase rates annually, to the benefit of customers. As a result, customers benefit annually because utility revenue increases are constrained by the required productivity offset and the resulting cap on revenues. In addition, at the end of the PBR plan the productivity gains achieved in the current regime are accounted for in a subsequent regime and passed on to customers in future rates, further benefiting customers.

Although it is difficult to predict the success of a PBR plan and the effect the plan will have on customer rates, the available empirical evidence from studies of the results of PBR plans demonstrate that PBR promotes lower customer rates over time. *An Overview of Performance Based Regulation And its Application* (Exhibit ES-AR/MK-3) provides a summary of the available studies of the effects of PBR plans on customer rates. These studies demonstrate that PBR can be expected to suppress the growth of customer rates over time.

D. Benefits will be more readily shared with customers under PBR.

Under COSR regimes, such as the current regulatory regime in New Hampshire, the effect of any efficiencies undertaken by a utility are not recognized and accounted for in customer rates until the utility returns with a base rates application. A firm under COSR that is achieving efficiency gains and higher returns has little incentive to return to the regulator with a new base rates application so that customers do not immediately benefit from the increased productivity through potentially lower rates.

PBR plans that include a consumer dividend, such as the stretch factor proposed by Eversource, more immediately share the benefits of newfound efficiencies with customers. A consumer dividend is usually applied to the PBR formula in first generation PBR plans to immediately share with customers the efficiency gains from the PBR plan that a utility is expected to achieve when first under a new incentive structure. The consumer dividend, whether in a first generation PBR plan or not, more immediately shares some of the annual productivity gains with customers throughout the stay-out period by providing an increment to the minimum level of productivity that is reflected in rates, thereby providing customers with on-going rate relief.

PBR plans that include an earnings sharing mechanism (ESM), such as the ESM proposed by Eversource, also share any surplus relative to a utility's allowed return on equity (ROE) with customers. When a utility exceeds the prescribed ROE, customers and the utility share the excess earnings through lower rates in the subsequent period.

E. PBR will better equip utilities to respond to changing industry dynamics.

Social, legislative and policy pressures to address the impact of climate change through decarbonization are affecting electric utilities. Electric distribution utilities like Eversource are in transition as supply side alternatives in the form of distributed generation resources and consumer self-supply, and demand side management alternatives supplant revenue sources in their legacy franchise markets. Distribution utilities' costs to provide service are often increasing faster than the expected growth in sales volumes from further electrification as they replace aging infrastructure and modernize their distribution grids to facilitate both increased electrification and customers' emerging needs, such as roof top solar connections, Net Energy Metering, and EV charging. In addition, cost pressures are emerging due to economic uncertainty and continuing elevated levels of inflation.

Utilities retain their obligations to serve under the regulatory bargain in an environment with increased risk that is affecting all aspects of their costs to provide service. Utilities are prohibited from exiting the market and must stand ready to supply energy services throughout their franchise territory, including to customers who are less dependent on grid-supplied energy. A well designed PBR plan provides utilities with the necessary incentives and the tools to respond to the demands of the energy transition. A well-designed PBR plan will:

- Provide strong incentives to control costs
- Provide more flexibly to address a changing operating environment
- Address the need for increased capital investment, potentially in advance of revenue growth
- Better equip utilities to satisfy their public service obligations to provide safe, reliable, least-cost service to their customers
- Safeguard the utilities' financial integrity given the current inflationary pressures and economic uncertainty.

V. The Objectives of a PBR Plan

The Commission would be well-served by considering the objectives of a well-designed PBR plan discussed in *An Overview of Performance Based Regulation And its Application* (Exhibit ES-RA/MK-3) when adjudicating the Company's application for approval of its proposed PBR plan. In my view, the balanced PBR Plan proposed by Eversource achieves the objectives of a sound PBR plan.

A PBR Plan should achieve the following:

- Result in just and reasonable rates.
- Emulate the incentives of a competitive market to the greatest extent possible. In this regard, the PBR plan should provide the Company with strong incentives to reduce costs.
- Provide a reasonable opportunity for the Company to recover its prudently incurred costs and earn a fair return.
- Ensure the Company does not unduly benefit from nor be unduly penalized for events outside of its control. In this regard, the PBR regime should ensure that the Company's financial integrity is safeguarded against unforeseen events or circumstances that are beyond the control of management.
- Be reasonably understandable by stakeholders.
- Avoid regulatory burden and ideally streamline regulation to reduce regulatory burden.
- Make parties better off relative to the current regulatory regime, so that all stakeholders, including the Company and its customers, equitably share in the benefits of the PBR plan.
- Consider the unique circumstances of the Company.

The Commission may consider the weight to be ascribed to each objective to determine the extent to which these objectives can be achieved. Clearly, there will be trade-offs among the objectives. However, in my opinion, the Commission should find that the choice of elements making up the Company's PBR plan work in harmony to achieve these objectives and provide a reasonable balance among the objectives and the obligations of the Company under the regulatory bargain, while more strongly focusing the Company on the achievement of efficiency gains to the benefit of customers.

VI. Some Considerations When Approving a PBR Plan

Predicting the likely success of a PBR plan relative to the Commission's objectives, as with any regulatory regime, is an educated guess because the results will not be fully known until the PBR plan plays out, somewhat unevenly, over its planned stay-out period. This is why I encourage the Commission to rely on the economic principles inherent in the PBR planning process and the intended outcome of the PBR plan it is being asked to approve.

A successful PBR plan strikes a balance among the many elements of the plan and the weight assigned to each element so that they ideally work together to achieve the Commission's objectives, all of which requires judgment on the Commission's part. Striking that balance is, in my view, the primary task before the Commission; a task that is not easily achieved and that will result in winners and losers, and the inevitable criticism that entails. To be clear, striking a balance is not an exercise in making sure all parties have an equal share of the proverbial pie. It is about finding an equitable outcome that reasonably achieves the Commission's desired objectives. This will inevitably require consideration of the trade-offs among competing objectives which, at times, present mutually exclusive alternatives.

Based on my experience in Alberta and knowledge of PBR plans in other jurisdictions, I offer the following.

1. A lot can happen during a stay-out period. During my 12-year tenure at the Commission, the electric utilities industry evolved significantly, driven by social, economic, and technological change. That evolution is continuing at an increasing pace. PBR plans should consider the social, economic, technological and market forces that are shaping the utilities industry.

2. Regulatory plans must be mindful that the conditions that shaped a regulatory regime in a prior period may not be relevant in a subsequent period, both across the industry and for individual companies. As the utility industry continues to evolve and becomes more complex, regulatory regimes should recognize that the past may not be a good indicator of the future.

3. PBR, based on an I – X formula, establishes a revenue stream based on industry cost trends, rather than linking revenues directly to the utility's own costs. However, a utility's revenues and costs must be periodically re-based so that the benefits of PBR are passed through to customers, while limiting the inherent administrative inefficiency of COSR to the greatest extent possible. Re-basing revenues and costs ensures that efficiency gains achieved in the prior regulatory period are accounted for in the subsequent period to the benefit of customers and that the going-in revenue requirement for the next period is sufficient to maintain the financial integrity of the

company and position it to continue to focus on long term sustainable productivity gains.

4. The going-in, or cast-off, revenue requirement and rates set up the PBR regime for success or failure. If the going-in rates are too low, then the utility will be set on an inadequate revenue trajectory and may be incentivized to focus on recovering a revenue shortfall through short-term unsustainable cost cuts that may need to be reversed in a subsequent period. Alternatively, if the going-in rates are too generous, then the incentives to find sustainable longer-term dynamic efficiency gains and permanent cost reducing innovations under the PBR plan will be dampened.

5. Setting the X factor (productivity offset) and a consumer dividend (stretch factor) can involve judgment. TFP studies and benchmarking to other utilities provide the underlying information used to inform the regulator's judgment, but fixing the amounts is a matter of balance among the competing objectives of a PBR regime.

6. The most difficult area to determine is the parameter(s) for capital additions during the PBR term. Capital additions can be difficult to forecast, can vary significantly among companies depending on demand growth and replacement cycles, and may be significantly influenced by legislative and public policy demands on a utility. Although utilities have considerable flexibility in dealing with the timing of their capital programs and can accommodate changes in circumstances, if the capital available to a utility under a PBR plan is unduly restricted, the utility may be constrained in finding sustainable long-term productivity gains to the detriment of customers.

7. Finally, no two PBR plans are likely to be identical. A PBR plan must consider the specific challenges faced by the company adopting PBR and the approved plan must be tailored accordingly.

VII. The Eversource PBR Plan Should be Approved.

In my opinion, the balanced PBR plan proposed by Eversource will ensure a continuation of the Company's customary delivery of safe and reliable least cost service to its customers, and at rates that are expected to be lower than achievable under the current regime. More importantly, it will also provide the increasingly necessary incentives to find further efficiencies and control costs, given the emerging demands on the Company's distribution system. As Mr. Foley, Mr. Coates, and Mr. Horton state in their direct testimony:

> The confluence of operating dynamics confronting electric distribution companies at this stage is unprecedented in the Company's experience. The operating environment for electric utilities is extraordinarily challenging, influenced by: (1) regional energy policy motivating changes in the nature, scale and technological intricacy of electric operations; (2) the emergence, adoption, and expansion of new technologies not

> contemplated by the existing design of the electric system or supported by PSNH's business enterprise systems; (3) evolving customer expectations and demand for broader use of and engagement with digital technologies; (4) challenges in hiring, training and retaining skilled personnel willing to make the types of personal sacrifices that storm restoration requires; (5) substantial quantities of aging infrastructure that must be replaced, upgraded and maintained to meet all other expectations; and (6) changing weather patterns with frequent winter and summer storms with significant impact.[9]

Electric distribution utilities like Eversource are in transition as supply side alternatives in the form of distributed generation resources and consumer self-supply, and demand side management alternatives supplant revenue sources in their legacy franchise market. With the proliferation of non-utility intermittent distributed generation, balancing supply and demand in real time becomes more challenging for grid operators like Eversource. The topology, composition, and management of electrical grids will need to adapt and adopt new technologies. Eversource is modernizing its electricity grid to facilitate the ways electricity will be produced, delivered, and consumed with the advent of distributed energy resources, and the prospect of increased electrification in response to climate change.

System needs are changing, and Eversource is responding. Its capital and operating costs are increasing to satisfy policy objectives and emerging customer demands, and to replace and upgrade aging infrastructure.[10] However, electricity grid modernization and the requirement to support further electrification may not be commensurate with an increase in load. If Eversource is unable to offset any potential revenue shortfall with the efficiency gains that can reasonably be expected under the proposed balanced PBR plan, then it will be required to resort to short term unsustainable O&M cost cuts or to delay potentially beneficial capital investments to maintain its financial integrity. This may also lead to necessary capital investments being shifted to future generations of customers, potentially at a higher cost.

The Company's proposal for a balanced PBR plan will not only provide it with strong incentives to control costs, but it will also give the Company the necessary flexibility to address its changing operating environment so it can continue to meet its public service obligations to provide safe, reliable, and least-cost service to its customers. The balanced PBR plan will result in just and reasonable rates that provide Eversource with a reasonable opportunity to recover its prudently incurred costs and maintain its financial integrity. The proposed PBR plan also includes elements to equitably share the benefits of the new

[9] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton., Page 13-14.

[10] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton.

regulatory regime with customers and to reduce regulatory burden to the benefit of both the Commission and customers.

In the remainder of my testimony, I discuss each of the elements of Eversource's balanced PBR plan and explain why, in my view, the Company's proposal should be approved as filed.

VIII. The PBR Plan for Eversource

Eversource is proposing a balanced PBR plan in the form of a revenue cap with a four-year term beginning August 1, 2025, similar in structure to other plans approved for Eversource's operating companies. Under the Company's proposal, temporary rates will go into effect on August 1, 2024, followed by permanent rates that will be effective starting August 1, 2025. The Company also proposes that the cast-off rates established in this proceeding, to be implemented in rates on August 1, 2025, will include net plant additions as of December 31, 2024.

The Company will then implement three rate changes (August 1, 2026, August 1, 2027, and August 1, 2028) as part of its proposed PBR plan. Under the plan, the annual authorized revenue requirement will be adjusted by the rate of inflation (I Factor), less a "stretch factor" of 15 basis points that provides an explicit consumer dividend where inflation exceeds two percent.

Going forward, the annual revenue requirement adjustment to take effect on August 1, 2026, 2027, and 2028 will include a capital revenue adjustment formula (K Factor) in the form of a K-Bar mechanism to recover capital investments not funded by the annual inflation adjustment. The proposal also includes an exogenous cost provision (Z Factor) that will credit to or recover from customers the effects of financially significant events beyond the Company's control, and an Earnings Sharing Mechanism (ESM) to credit customers with earnings beyond a 25 basis point threshold. A series of reliability metrics to assess the Company's operating performance during the stay-out period is also proposed.

As discussed below, each of the elements of Eversource's proposal taken together satisfy the objectives for a well-designed PBR plan and provide a reasonable balance among the objectives of a well-designed PBR plan and the Company's own objectives to continue to provide safe, reliable, and least-cost service to its customers.

A. Going In Revenue Requirement

The Company has filed a comprehensive base distribution rates application supported by all of the information required by the Commission's rules to establish the revenue requirement and going-in rates to be effective on August 1, 2025. [11] [12]

The first annual compliance filing computation for the PBR plan that will apply the annual revenue requirement adjustment formula will be submitted to the Commission on or before April 1, 2026, with any necessary adjustment to rates to recover the revenue requirement on a forecast basis proposed to take effect on August 1, 2026. The Company is requesting that capital additions expected to be in service by December 31, 2024 be recognized in permanent rates effective August 1, 2025. Given that the going in revenue requirement will be in effect for nearly two years before the annual revenue requirement adjustment formula is applied to adjust rates, this proposal is prudent and necessary to establish rates that reflect the Company's costs and should be approved by the Commission.

It is important to recognize that the objective in calculating the base year revenue requirement is to ensure that the going-in rates are both adequate and not reflective of monopoly profits so as to be just and reasonable, as the annual revenue requirement adjustment formula produces just and reasonable rates only to the extent that the going-in rates are just and reasonable. The going-in revenue requirement and going-in rates set up the PBR regime for success or failure. If the going-in rates are too low, then the Company will have inadequate revenue throughout the stay-out period and may be incentivized to focus on recovering a revenue shortfall through short-term unsustainable cost cuts that may need to be reversed in a subsequent period. This outcome would undermine one of the fundamental objectives of PBR, which is to incentive the Company to find sustainable long term efficiency gains.

B. Annual Revenue Requirement Adjustment Formula

Following the form of the generic formula discussed in *An Overview of Performance Based Regulation And its Application* (Exhibit ES-AR/MK-3), the revenue cap formula for the proposed balanced PBR plan is as follows:[13]

$$Rev\ Requirement_t = \left(Rev\ Requirement_{t-1}\ x\ (1 + I_t - X - CD)\right) + Z_t + K_t + ESM_t$$

Where:

[11] Attachment ES-REVREQ-1 (Temp) provides the *Temporary Rate Revenue Requirement Analysis* from Company Witnesses Ashley N. Botelho and Yi-an Chen.

[12] Attachment ES-REVREQ-1 provides the *Permanent Rate Revenue Requirement Analysis* from Company Witnesses Ashley N. Botelho and Yi-an Chen.

[13] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton.

Rev $Requirement_t$ = the revenue requirement in the current (forecast) period

Rev $Requirement_{t-1}$ = the approved revenue requirement in the prior period

I = GDP-PI and must be non-negative and may not exceed 5 percent

X = Zero

CD = 0.15 when I exceeds 2 percent

Z = an exogenous cost adjustment

K = a capital revenue adjustment

ESM = an earnings sharing adjustment

The individual elements of Eversource's proposed annual revenue requirement adjustment formula are discussed below. In my opinion, the proposed adjustment formula should be approved.

C. The Formula Excludes a Growth Factor

As explained further in *An Overview of Performance Based Regulation And its Application* (Exhibit ES-AR/MK-3), PBR formulas that cap overall revenue should theoretically include a customer growth factor to adjust for incremental (decremental) revenues from new (lost) customers that would otherwise not be accounted for, thereby either over- or under-funding the Company. However, the annual revenue requirement adjustment formula proposed by Eversource excludes a growth factor.

Because Eversource is not proposing to adopt a revenue decoupling mechanism, the Company is proposing to give effect to the necessary adjustment to rates each year over the term of the plan by holding billing determinants constant. In so doing, the Company is bearing the risk of lower revenues resulting from net metering or energy efficiency programs, and if revenues increase because of increased electrification, the Company will receive additional revenues that will help to offset the costs associated with serving increased load. This proposal is, in my view, both a reasonable and efficient way to account for actual changes in customer volumes over the term of the PBR plan.

However, if the Commission determines that a revenue decoupling mechanism is warranted, in conjunction PBR, then the proposed revenue requirement adjustment formula should be modified to include a growth factor. If revenue decoupling is implemented, it will claw back any revenue beyond the revenue requirement approved by the Commission under the PBR plan and deprive the Company of growth-related revenue that would otherwise offset the costs associated with serving increased load. Including a growth factor in the PBR formula will adjust for customer growth in this circumstance.

D. Inflation Factor

Eversource is proposing that for each year that the annual revenue requirement adjustment formula is applied to adjust revenue, the inflation (I) factor will be the annual percentage change over the most recent four quarterly measures of GDP-PI as at the fourth quarter of the year to align with its proposed annual filing and revenue requirement adjustment schedule. The I factor will not exceed 5 percent or fall below zero percent.

GDP-PI is a reasonable indicator of the inflation incurred by the Company. GDP-PI is also consistent with the I factor adopted universally for revenue capped PBR plans in the U.S. and is consistent with the derivation of the empirical X factor calculated by Dr. Ros in his testimony (Exhibit ES-AR-1), which assumed a measure of economy-wide output inflation.

Eversource is proposing to cap the I factor at 5 percent, in the event inflation exceeds that threshold. This will require the Company to absorb any inflationary costs in excess of the threshold. This is a significant customer benefit. The Company is also proposing an inflation factor floor of zero, in the unlikely event that inflation is negative in the prior period. Although there is no apparent theoretical basis for restricting the I factor to being no less than zero, it is unclear whether utilities would see the effects of a negative empirical GDP-PI in a given year flow fully through into lower overall costs. For example, it is unlikely that collective labor agreements would be renegotiated downward in response to a negative GDP-PI, unless deflation occurred over a period of several years. More importantly, the Company is voluntarily adopting a zero X factor and proposing an ESM with a very narrow deadband that returns most earnings above the allowed ROE to customers in lower rates; all of which in my opinion represents a considerable benefit for customers and potentially a significant challenge for Eversource that will incentivize the Company to find efficiencies. On balance, an inflation factor floor of zero is reasonable.

The Commission should approve the derivation of the I factor proposed by the Company.

E. Productivity Offset (X Factor)

The evidence of Dr. Ros concludes that:

> Putting all the components of the X-Factor together—the electric industry TFP and input price growth as well as the economy-wide U.S. TFP and input price growth—we calculate that during the period 2000 to 2022, the X-Factor averaged -1.42%. Therefore, a revenue-cap PBR plan for an electric-distribution company that has just and reasonable going-in rates and has a PBR formula that results in annual allowed revenue changes in years two, three and four of GDP-PI + 1.42% results in rates that are just and reasonable and mimic the outcomes that one would

observe under competition.[14]

Eversource is proposing a productivity offset (X) factor of zero, despite the finding of Dr. Ros. Approving a zero X factor as proposed will require significantly greater efficiency gains than would result if the factor is set at -1.42 percent as proposed by Dr. Ros. Because this larger productivity offset is set out in the I-X mechanism in the annual revenue requirement adjustment formula, customers will be guaranteed a more immediate and larger share of benefits in the annual rates adjustments; benefits beyond the historically approved consumer dividend amounts provided for in most PBR plans.

F. Consumer Dividend (Stretch Factor)

The Company is proposing to implement an explicit consumer dividend of 15 basis points when inflation exceeds two percent. In my view, it is reasonable to approve the proposed consumer dividend of 15 basis points to be applied only when the inflation (I) factor in the annual revenue requirement adjustment formula exceeds two percent.

The proposed consumer dividend, in the context of the balanced PBR plan, shares the benefits of the PBR plan with customers by tempering rate increases when inflation is above the proposed two percent threshold. In my view, the two percent threshold is reasonable because it aligns with the Federal Reserve's target rate of inflation. When inflation exceeds the two percent threshold, at which point the Federal Reserve may deem it necessary to take action to reduce inflation, it can reasonably be assumed that customers may require some additional rate relief in the face of higher inflation and the 15-basis point consumer dividend assists in providing some relief.

Also, as discussed above, the Company is proposing a productivity offset (X) factor of zero, despite the evidence from Dr. Ros that the average empirical industry productivity is -1.42 percent. This requires the Company to find efficiencies sufficient to absorb this empirical negative productivity, which amounts to a significant benefit for customers akin to a consumer dividend. In my opinion, the proposed explicit consumer dividend coupled with the zero-productivity offset is generous. In this regard, I note that approved consumer dividends rarely exceed -0.30 percent.[15] [16]

There is a balance to be struck when approving a consumer dividend. While a higher consumer dividend will result in greater immediate customer benefits and incentivize the Company to find additional productivity gains under its balanced PBR plan, this incentive

[14] Exhibit ES-AR-1, at page 3.

[15] *An Overview of Performance Based Regulation And its Application* (Exhibit ES-MK-3), page 28.

[16] An assessment of the potential cost efficiencies gained during a PBR term in Massachusetts found that only a 0.30 percent cost savings can be achieved over a period of less than five years. See, Massachusetts Department of Public Utilities, D.P.U. 20-120.

must be balanced against the need for the Company to earn sufficient revenue so that it can provide reliable service to customers and have a reasonable opportunity to earn its allowed return. If the consumer dividend is set beyond the level of productivity the Company can be reasonably expected to achieve annually over the term of its PBR plan, then the Company's financial integrity may be at risk, and it may be incentivized to focus on short term non-sustainable O&M adjustments or delay capital investments. The combination of the explicit consumer dividend and the zero X factor are generous, in my opinion, and will challenge the Company to find sufficient efficiency gains over the stay-out period. However, Eversource is confident that it will be able to achieve the efficiency gains required annually in its PBR proposal while maintaining its financial integrity and satisfying its obligation to provide safe and reliable service at the lowest possible costs.

The Commission should approve the Company's proposed X factor and consumer dividend as filed.

G. Capital Factor (K-Bar)

The Company proposes to use a "K-Bar" mechanism similar to the approach adopted for another Eversource operating company, NSTAR Electric, to provide supplemental revenue associated with rate base growth not accounted for by the "I-X" mechanism in its annual revenue requirement adjustment formula, with some adjustments. The proposed K-Bar formula is based on a rolling three-year historical average of capital additions, adjusted by the I-X formula.

In adopting the "K-Bar" approach, the Company is proposing a restriction on capital investments eligible for recognition through the K-Bar over the PBR term by capping the annual capital spending eligible for inclusion in the three-year rolling average. The cap will be set at ten percent above the forecasted annual capital spending included in the Company's five-year capital budget.[17] In my view, this is an additional customer benefit that will further incentivize the Company to seek out efficiencies in its capital spending.

The purpose of the K factor element in the PBR plan is to ensure that the Company has sufficient revenues to support capital infrastructure investment requirements beyond what is provided in the annual I-X adjustment while maintaining the incentives of PBR to be an efficient cost performer. The objective is to balance the genuine capital requirements of the Company against the assumed risk that the Company will over-invest or under-invest in capital over the PBR term.

A well-designed annual K-bar formula adjustment for capital requirements not recoverable under the I-X mechanism will provide a reasonable balance between providing a capital factor that is too generous and permitting the Company to fund necessary capital additions. I consider that the three-year rolling average base K-Bar amount proposed by

[17] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton.

the Company is reasonable given that the industry is in transition and capital additions are now more difficult to forecast; and recognizing that capital needs are growing to provide for grid modernization and other requirements to support the energy transition and decarbonization objectives. I note that Eversource is proposing to undertake a targeted suite of grid enhancement activities to improve the Company's service capabilities. The shorter three-year base K-Bar amount will allow the K-Bar calculation to capture more of the actual spending required to support prudent capital investment, including the targeted suite of grid enhancement activities.[18]

The Company is proposing that co-optimization of significant customer-driven investments to accommodate major, large new or expanded customer loads be recoverable when they exceed the K-Bar cap on capital spending.[19] Infrequent significant capital investments such as these may be considered "outside the normal course of business" and when they are deemed by the Commission to be prudent, a mechanism to provide for additional supplemental capital is warranted if the PBR plan does not facilitate recovery of the investment-related costs.

As explained further in *An Overview of Performance Based Regulation And its Application* (Exhibit ES-AR/MK-3), a capital tracker is the alternative method generally adopted in PBR plans to account for supplemental capital related to specific investments approved by the regulator that are not recoverable under other elements of the plan, often in conjunction with a K-Bar mechanism. However, trackers can be administratively onerous and exhibit some of the shortcomings of the current step adjustment regime. In my opinion, the Company's proposal has efficiency benefits relative to the capital tracker approach adopted in other PBR plans to provide for prudent capital investments that are outside the normal course of business and are not recoverable through other mechanisms in the proposed PBR plan.

The proposal avoids the requirement for a proceeding to approve the implementation of a tracker for the relevant forecast capital costs related to the co-optimization of significant customer-driven investments and the subsequent requirement for a proceeding to review the prudence of the actual costs and approve their inclusion in the Company's revenue requirement. Under the Company's proposal, the costs associated with the co-optimization of significant customer-driven investments will be included in the annual PBR compliance filing for recovery in the approved revenue requirement as a K-Bar adjustment. The Commission will thereby be provided with oversight of the investments and related costs as part of the annual PBR filing proceeding. As with other K-Bar related capital investments, the prudence of the co-optimization of significant customer-driven investments will be reviewed at the next base rates proceeding along with the other capital investments

[18] Ibid.

[19] Ibid.

undertaken during the PBR term. It is also noteworthy that customers are rate-protected through the proposed earnings sharing mechanism from any over-earning that might result from a mis-calculation under the capital investment cost recovery mechanisms in the PBR plan.

On balance, within the context of the overall PBR plan, Eversource's K-bar proposal, including the Company's proposal to recover the costs associated with co-optimization of significant customer-driven investments, is reasonable and should be approved.

H. Exogenous Adjustment Factor

The Company is proposing to include a Z factor provision in its annual revenue requirement adjustment formula to account for exogenous costs that would not otherwise be accounted for in the PBR plan. Exogenous costs are positive or negative cost changes resulting from events that are beyond the Company's control and not reflected in GDP-PI. The Company proposes to include any approved exogenous cost recovery in its annual PBR compliance filing.

The Company is proposing the following criteria for recovery of costs arising from an exogenous event.[20]

- The cost change is beyond the Company's control.
- The cost change arises from events outside management's control, such as accounting requirements, regulatory, judicial, or legislative directives or enactments, among other exogenous events;[21]
- The cost change is unique to the electric distribution industry as opposed to the general economy.
- The cost change exceeds a significance threshold for qualification, which the Company is proposing initially to be $1.5 million. The threshold amount will be adjusted annually by the amount of the I factor in the annual revenue requirement adjustment formula. If the threshold is reached, the Company will qualify for recovery (or refund) of the qualifying cost without deducting any amounts below the threshold.

Exogenous cost changes can be permanent in nature requiring an annual adjustment to the revenue requirement, or non-recurring. The Company proposes to reflect recurring exogenous costs as a change in base rates, while non-recurring exogenous costs will be

[20] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton

[21] The following are examples that would qualify for recovery as an Exogenous Event (whether positive or negative): (1) State Initiated Cost Change, (2) Federally Initiated Cost Change, (3) Regulatory Cost Reassignment, or (4) Externally Imposed Accounting Rule Change. The preceding list is not comprehensive but provides examples of types of events that are outside the Company's control.

collected as a Z factor amount in the relevant annual revenue requirement adjustment or as an amortized expense over future annual revenue requirement adjustments as required, depending on the magnitude of the cost adjustment.

The proposed threshold of $1.5 million equates to approximately 10 basis points of the Company's initial return on equity amount in its going-in revenue requirement. This degree of change in return on equity would have a significant effect on the Company, and potentially its customers, if left unchecked.

In my opinion, the Z factor proposal and threshold amounts provide a reasonable opportunity for the Company to recover significant costs that are not accounted for in GDP-PI and not recoverable though the I-X mechanism. It also benefits customers when exogenous events result in a significant reduction in the Company's costs. The Z factor proposal should be approved.

I. Earnings Sharing Mechanism

The Company is proposing an asymmetrical earnings sharing mechanism (ESM) that will share with customers 75.00 percent of earnings over 25-basis points above the authorized return on equity (ROE). Because the ESM is asymmetrical, customers will not be required to assist the Company in recovering any shortfall in earnings below the authorized ROE.[22]

Earnings sharing mechanisms provide an opportunity for customers to more immediately share in the benefits of a PBR plan beyond the productivity gains assumed in the X factor, rather than receiving the benefits only at the end of the PBR term when the revenue requirement is rebased. This can provide for more intergenerational equity across regulatory regimes. However, an earnings sharing mechanism may also blunt the efficiency incentives of the plan if the company's shareholders are prohibited from enjoying sufficiently the additional return accruing from its success under the plan.

The Company's earnings sharing proposal is, in my view, generous for customers relative to the ESM mechanisms normally adopted for PBR plans with a one hundred basis point deadband. The overall PBR plan should nonetheless encourage Eversource to seek out efficiency gains given the zero X factor and the other elements of the balanced PBR plan. If the Company is successful to the point that earnings sharing is triggered, then customers will more immediately receive a significant share of the benefits of that success.

J. Term and Stay-Out Period

Eversource is proposing a 4-year term for its PBR plan.[23] Given that the market for the electric utility industry is evolving and system needs are changing as discussed above, no more than a 5-year stay-out period is warranted and the proposed stay-out period will

[22] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton.

[23] Ibid.

provide the Company with ample opportunity to seek out efficiency gains while not unduly increasing risk. However, Eversource is also proposing that it be provided the opportunity to extend the stay out period for a second term, should the Company choose to do so.

K. Minimum Return on Equity Trigger

Eversource is proposing that the Commission adopt the PBR Plan, inclusive of a 4-year stay-out commitment such that PBR rate changes would occur on August 1, 2026, August 1, 2027, and August 1, 2028, and the earliest new rates could be set in the context of the Company's next base rate proceeding would be August 1, 2029.

The Company is also requesting the opportunity for the Company to propose a continuation of the PBR Plan for a term up to and including four years beyond August 1, 2029. Where the PBR Plan is allowed to be extended, the Company proposes that the earnings sharing mechanism allow PSNH to file for a base-rate adjustment in the event that its earned ROE falls below seven percent for two consecutive quarters, at which point the Company would be allowed to file for a base rate adjustment during the extended term. This proposed minimum return on equity trigger is consistent with the trigger approved by the Commission as part of the settlement agreement in Docket Number DE-09-035.[24]

It is noteworthy that the proposed trigger would not apply in the first four years of the plan, and that it does not protect the Company from downside risk. The trigger does not propose to allow the Company to recoup the earnings attrition from a prior period in the change to its permanent distribution rates. Any earnings attrition will only be accounted for on a going-forward basis. As such, customers are protected from being required to fund any unrealized earnings, consistent with the Company's commitment to assume the risk of earning a lower return on equity in its proposed ESM.

An off ramp is intended to protect the financial integrity of the Company should unforeseen circumstances arise or come to light as the term of the PBR plan unfolds which may have a material effect on either the Company or its customers and which cannot be addressed through other features of the plan.

The off ramp proposed by the Company is an important safeguard that should be approved.

L. Reliability Metrics

Eversource is proposing several reliability metrics to allow the Commission and other stakeholders to assess the Company's performance during the stay-out period.[25] Included in the reliability metrics is a set of service quality metrics designed to ensure that the Company maintains its high service quality standards during the PBR term. The Company's

[24] Direct Testimony of Douglas W. Fowley, Roberts S. Coates, Jr. and Douglas P. Horton

[25] Ibid.

proposed service quality metrics include penalties assessed against the Company that will be distributed to customers as a credit in the subsequent year. The proposed reliability metrics provide the necessary incentives to deliver reliable service and provide for customers' evolving requirements at the lowest reasonable cost. The reliability metrics should be approved as proposed.

IX. The PBR Plan Proposed by Eversource Satisfies the Objectives of a Well-designed PBR Plan

The Company's plan results in just and reasonable rates over the term and stay-out period of the plan. The Company is afforded a reasonable opportunity to recover its prudently incurred costs and earn a fair return, while annual rate increases are limited by the revenue requirement adjustment formula. The plan includes adequate safeguards to ensure the Company does not unduly benefit from nor be unduly penalized for events outside of its control.

The plan provides the Company with the latitude, flexibility, and robust incentives to find the efficiencies required to respond to the emerging demands on its distribution system. In so doing, the proposed PBR plan promotes the objectives of economic efficiency and cost control and should result in lower rates than would likely be achieved under the current regime because the plan provides more powerful efficiency incentives and shares any resulting earnings gains with customers.

The PBR plan, with its 4-year stay-out period and its proposed annual filing requirements, will result in a reduced administrative burden for the Commission and for the Company, thereby reducing the related costs that are ultimately borne by customers and freeing management to focus on achieving the objectives of the plan to provide safe, reliable, and least-cost energy service.

Because the PBR plan provides more latitude and flexibility than the current regime with respect to investment, it better addresses the need for increased capital investment, and it permits Eversource to better respond to the evolving industry environment.

The proposed reliability metrics provide the necessary incentives to ensure the Company's continued high standards of safety, service reliability, customer service. The metrics also focus Eversource on comprehensive, specific measurable results.

The PBR plan is reasonably understandable by stakeholders and should result in significant benefits for all stakeholders relative to the current settlement agreement- base regulatory regime.

Finally, the PBR plan considers the unique circumstances of the Company in New Hampshire.

As discussed throughout my testimony and as explained in Eversource's own testimony, the Company's proposed PBR plan is designed to:

- Provide strong incentives to control costs
- Provide more flexibly to address the changing operating environment
- Address the need for increased capital investment, potentially in advance of revenue growth
- Better equip the Company to satisfy its public service obligations to provide safe, reliable, least-cost service to its customers
- Safeguard its financial integrity

In my opinion, the proposed plan will position Public Service Company of New Hampshire to achieve these objectives and should be approved as filed.

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With over 30 years of experience in the regulated utilities sector, I have worked in the areas of regulation and public policy, external relations, marketing, strategy and business development, and mergers and acquisitions. I have over 20 years of corporate experience in the telecom sector, where I was Vice President, Economic Affairs at one of Canada's largest telecommunications companies. In 2020 I concluded my tenure with the Alberta Utilities Commission, where I was a Commission member for twelve years, including six years as Vice Chair and two years as Chair of the Commission. I am now a researcher, writer, and consultant in the utilities sector, advising clients on incentive regulation, rate design, facilities applications, regulatory strategy, integration of distributed energy resources into the grid, energy transitions, utility business models and regulatory renewal, among other matters.

Major Areas of Expertise

Public Utility Regulation / Policy

- As Vice Chair and then Chair of the Alberta Utilities Commission, managed the regulatory agenda and overall policy direction of the Commission, including day to day organizational, management, financial and policy decisions.
- While at the Alberta Utilities Commission, issued over 1400 decisions on performance-based regulation, revenue requirement, rate setting, facilities' cost approvals and siting, rate of return, utility acquisitions and divestitures, market design, etc.
- While at TELUS, developed and executed activities aimed at influencing the Federal Government Standing Committee on Regulations and Government. Prepared submissions and made presentations to external stakeholders, including the Legislative Committees on the Broadcasting Act and the Telecommunications Act.
- Conceived and implemented an innovative proposal to bring the telecommunications industry together with consumer groups to negotiate a settlement in lieu of an upcoming proceeding. Garnered industry and regulator support for the proposal, developed and implemented the process and framework for the negotiations, and participated as the company's chief negotiator.
- Created the Economic Affairs Department at TELUS to support strategy development in customer facing business units. As Vice President, Economic Affairs, ensured the organization's regulatory strategies aligned with corporate strategies.

Consulting

- Assisting Eversource to develop its first Performance Based Regulation filing before the New Hampshire Public Utilities Commission and providing expert testimony.
- Advised the City of Westerville Electric Division (Ohio) on matters related to its Cost-of-Service and Rate Design and providing expert testimony.
- Advised BC Hydro on its 2023 Performance Based Regulation proposal to the British Columbia Utilities Commission.
- Provided strategic advice to an Alberta distribution utility on its 2023 Performance Based Regulation application before the Alberta Utilities Commission under a confidentiality agreement.
- Assisted Fitchburg Gas and Electric to develop its first Performance Based Regulation filing before the Massachusetts Department of Public Utilities and provided expert testimony.
- Assisted BC Hydro in its Performance Based Regulation Review proceeding before the British Columbia Utilities Commission.
- Advised BC Hydro on rate design matters, including redesigning the consumer tariff, and industrial transmission tariff.
- Drafted survey report on electric vehicle charging rates in North America for BC Hydro.
- Drafted survey report on load attraction plans in North American electric utilities for BC Hydro.
- Assisted the Connecticut Public Utility Regulatory Agency in a workshop on performance-based regulation.
- Advised a client in a confidential arbitration and filed expert evidence before the arbitration tribunal.
- Assisted the Public Utilities Regulatory Agency (Connecticut) in a workshop to consider adopting a performance-based regulation plan.
- Assisted the Hawaii Public Utilities Commission in a workshop to consider its next generation performance-based regulation plan.
- Assisted the Canadian Gas Association and Canadian Electricity Association with "The Future of Utility Regulation in Canada" project.

Academia

- Over 20 years of experience teaching as an adjunct lecturer at University of Alberta and University of Calgary in business management, strategy, and planning.

Employment History

Kolesar Buchanan & Associates Ltd Current
Managing Principal / Consultant

Alberta Utilities Commission

Chair	2018 to 2020
Vice Chair	2012 to 2018
Commission Member	2008 to 2012
Freelance Consultant	2007 to 2008

TELUS Corporation

Vice President, Economic Affairs	2004 to 2007
Assistant Vice-President, Regulatory and Public Policy	2000 to 2004
Director, Regulatory	1994 to 2000
Senior Marketing and Business Development Analyst	1993 to 1994
Director, Policy & Government Affairs	1992 to 1993
Regulatory Analyst	1988 to 1992

Public Utilities Board of Alberta

Applications Officer	1985 to 1988

Alberta Government Telephones

Economic (Costing & Capital Budgeting) Analyst	1980 to 1985

Education

MBA – Managerial Economics and Finance – University of Ottawa	1979
BA (Honours) – Philosophy – University of Ottawa	1976

Publications, Testimony & Selected Presentations

Publications

- Kolesar, M. and Levin, S. (2004) “Rationalizing interconnection arrangements in competitive communications markets” in: Bohlin, E., Levin, S.L., Sung, N. & Yoon, C.H. (Ed); Global economy and digital society, London, UK Elsevier.
- Kolesar, M. and Weisman, D.L. (2003) “Accommodative competitive entry policies and telecommunications regulation” *Info*, Vol 5 No 1 pp.34-40.
- Kolesar, M.B. and Galbraith, R.W. (2000) “A services-marketing perspective on e-retailing: implications for e-retailers and directions for further research” *Internet*

Research, Vol 10, No 5, pp. 424-438.

- Glass, V., Kolesar M., Tadiff T., and Williamson, B. "Provider of Last Resort in Emerging Electricity Markets: Lessons from Telecommunications Deregulation" *The Electricity Journal*, Volume 35, Issue 1, January–February 2022, 107064.
- Kolesar M. Löbbe Sabine, et al. "Energy Communities: a North American Perspective." *Energy Communities: Customer-Centered, Market-Driven, Welfare-Enhancing ?*, Academic Press, Amsterdam, 2022.
- Kolesar M. Re-thinking, Re-packaging and Repricing the Grid and Retail Electricity in: Sioshansi, F. (Ed); The Future of Decentralized Electricity Distribution Networks, London, UK Elsevier, 2023

Testimony

- Expert testimony for City of Westerville Electric Division (Ohio)on rate design
- Expert testimony before the Massachusetts Department of Public Utilities on Performance Based Regulation for Fitchburg Gas and Electric
- Expert testimony before the British Columbia Utilities Commission on the EV charging market in North America
- Expert testimony in a confidential arbitration proceeding, 2022
- Expert testimony before the British Columbia Utilities Commission: British Columbia Hydro and Power Authority (BC Hydro) Review of BC Hydro's Performance Based Regulation Report, Project No. 1599045, November 27, 2020.
- Testimony before Canadian Radio-television and Telecommunications Commission in *Review of Price Cap Framework Public Notice CRTC 2006-5.* Subject Matter: Telecom Markets in Canada.
- Testimony before Canadian Radio-television and Telecommunications Commission in *Price Cap Review and Related Issues Public Notice CRTC 2001-37*. Subject Matter: Quality of Service.
- Testimony before the Canadian Radio-television and Telecommunications Commission in *New Media- Call for Comments Public Notice CRTC 98-2 & Public Notice CRTC 1998-82.* Subject Matter: Public Policy Implications of the Impact of New Media on the Canadian Broadcasting Industry.

Invited Presentations

- "Repackaging & Repricing the Grid & Retail Rates" GridFwd2023, Skamania Lodge, Oregon, October, 2023
- "Utility entry into the commercial EV charging market" CRRI Advanced Workshop in Regulation and Competition 34th Annual Western Conference, Hyatt Regency, Monterey, California, June, 2023
- "Rethinking the Distribution Utility Business Model" CRRI Advanced Workshop in Regulation and Competition 34th Annual Western Conference, Hyatt Regency, Monterey, California, June, 2023
- "Utility Entry into the Commercial EV Charging Market" EUCI Canadian Rate Design Conference, Vancouver, September 27-28, 2022

- Keynote Address, Rutgers Center for Research in Regulated Industries 33rd Annual Western Conference, Monterey, California. June 22-24, 2022
- Keynote Address Rutgers Center for Research in Regulated Industries 40th Annual Advanced Workshop in Regulation and Competition, Atlantic City New Jersey, June 1-3, 2022
- "Regulating for Net Zero," Electricity Canada 2022 Regulatory Forum, Discussion Panel, May, 2022
- "The More We Get Together, The Happier We'll Be": The Prospects for Western Grid Integration" Grid Days 2021, Panel Moderator, October 19, 2021.
- "Using PBR to Help Achieve Decarbonization Goals", EUCI annual rate design conference, November 16, 2021.
- "Innovative Regulatory Policies to address the four Ds", Canadian Electricity Association Regulatory Forum, June 2, 2021.
- "How will the pandemic change the electric utility industry's regulatory bargain? A Second Look", Rutgers University, Centre for Research in Regulated Industries, Webinar, July 28, 2020.
- Keynote Address, Grid Forward 2019, Seattle, Washington, October 2019.

Total Factor Productivity and the X-Factor for use in PSNH PBR Plan

Agustin J. Ros, Ph.D.

Prepared for: Public Service Company of New Hampshire
June 11, 2024

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Tables

I. Introduction

A. PSNH PBR Plan

The Public Service Company of New Hampshire d/b/a ("PSNH" or the "Company") is proposing a change in base distribution rates, along with implementation of a four-year Performance Based Ratemaking ("PBR") plan. The Company's PBR plan is a *revenue-cap* plan where the Company's revenue will be adjusted annually based upon a PBR formula.

PSNH is proposing to establish initial rates based upon a traditional, cost-of-service ("CoS")/rate-of-return ("RoR") proceeding that, when completed, results in just and reasonable rates.[1] The just and reasonable rates are the *going-in* rates of the Company's PBR plan and will be in effect during the first year of the plan. In subsequent years of the Company's PBR plan, i.e., years two, three and four, PSNH will be permitted to change rates based upon a revenue-cap PBR formula.[2]

The PBR formula has several components. First and foremost, the PBR formula relates changes in PSNH's allowed revenues to the change in inflation in the overall economy ("I") minus changes in the *differences* in the total factor productivity ("TFP") and input price growth between the electric-distribution industry and the overall economy, the latter component commonly referred to as the "X-Factor." This is the PBR formula for the X-Factor when the measure of inflation (I) is an economy-wide measure, such as the gross domestic product price index ("GDP-PI"), which is the measure of inflation that the Company is proposing in its PBR formula. Accordingly, under the PBR plan, PSNH will be given the opportunity to achieve revenues in years two, three and four of the plan based upon the formula: "I - X".

There are additional components of the Company's PBR formula reflecting key provisions of the Company's overall PBR plan, and these additional components can decrease or increase the Company' allowed revenue in years two, three and four of the PBR plan. The Company's PBR plan includes an earnings-sharing mechanism that requires the Company to share earnings with customers on a 75/25 basis (75 percent to customers and 25 percent to the Company) when the earned return on equity for distribution operations exceeds 25 basis points above the return on equity authorized in this case. That is, the earnings-sharing mechanism has a 25-basis point deadband, where earnings sharing begins after earnings exceed 25 basis points above the authorized return on equity.

[1] We use the term CoS regulation and RoR regulation interchangeably throughout this report.

[2] Specifically, PSNH filed temporary and permanent rates to be in effect from August 2024 through August 2025 and from August 2025 through August 2026, respectively. PSNH set temporary and permanent rates based upon a CoS methodology. The PBR revenue-cap plan will then determine rates for the period August 1, 2026 through July 31, 2029.

Eversource is proposing that the Commission adopt the PBR Plan, inclusive of a 4-year stay-out commitment such that PBR rate changes would occur on August 1, 2026, August 1, 2027, and August 1, 2028, and the earliest new rates could be set in the context of the Company's next base rate proceeding would be August 1, 2029.

The Company is also requesting the opportunity for the Company to propose a continuation of the PBR Plan for a term up to and including four years beyond August 1, 2029. Where the PBR Plan is allowed to be extended, the Company proposes that the earnings sharing mechanism allow PSNH to file for a base-rate adjustment in the event that its earned ROE falls below seven percent for two consecutive quarters, at which point the Company would be allowed to file for a base rate adjustment during the extended

The Company's PBR plan includes a "K-Bar" to provide supplemental revenue to support rate base growth over and above the "I – X" component of the PBR formula. The PBR plan includes an "exogenous" cost factor that can increase or decrease the Company's allowed revenues to account for cost changes that are beyond the Company's control and not reflected in the measure of inflation in the "I – X" PBR formula—*i.e.*, GDP-PI. There is also a service-quality component to the Company's PBR plan that will result in penalties if performance falls below a baseline standard.

Lastly, the Company's PBR plan includes a "stretch factor"—also referred to as a consumer dividend—that, all else equal, lowers the Company's allowed revenues in years two, three and four of the PBR plan by 15 basis points in the event inflation exceeds two per cent. The stretch factor is a direct customer benefit that shares the immediate expected benefits of the PBR plan with customers.

B. Summary of Results

The X-Factor represents the *differences* in TFP and input price growth between the electric-distribution *industry* and the overall economy. To determine the economically appropriate X-Factor to use in an "I – X" revenue-based PBR formula for an electric-distribution company, we begin by calculating the electric-industry TFP and input price growth. We have constructed an excel-based electric-industry TFP model using data from the Federal Energy Regulatory Commission ("FERC"), the Energy Information Administration ("EIA") and other sources.

TFP growth is the difference in the rate of growth of a company's output and the rate of growth of a company's inputs. We have data available for 87 electric-distribution companies in our TFP model. These 87 companies represent approximately 60% of total U.S. electric customers.[3] We calculate output and input indices for each company for each year over the period 2000 to 2022. Our TFP model shows that electric-industry TFP growth during the period 2000 to 2022 averaged **-0.26%**. The TFP model has, as intermediate calculations, the input price growth of each company. During the period 2000 to 2022, electric-industry input price growth averaged **3.39%**.

Information on economy-wide U.S. TFP growth is readily available from the U.S. Department of Labor and economy-wide U.S. input price growth can be readily calculated using economy-wide U.S. TFP growth and GDP-PI data from the U.S. Bureau of Economic Analysis. Economy-wide U.S. TFP growth during the period 2000 to 2022 averaged **0.77%**, while economy-wide U.S. input price growth averaged **3.01%**.

Putting all the components of the X-Factor together—the electric industry TFP and input price growth as well as the economy-wide U.S. TFP and input price growth—we calculate that during the period 2000 to 2022, the X-Factor averaged **-1.42%**. Therefore, a revenue-cap PBR plan for an electric-distribution company that starts with "just and reasonable" going-in rates and is subject to a PBR formula that results in annual allowed revenue changes in years two, three and four of **GDP-PI + 1.42%** results in rates that mimic the outcomes that one would observe under competition, while remaining "just and reasonable" under applicable ratemaking standards.

Although the X-Factor we calculate permits the Company to achieve revenue growth equal to GDP-PI + 1.42% while having rates remain "just and reasonable," the Company has decided to set the X-Factor at zero so that the Company will achieve revenue growth equal to GDP-PI.

In addition to the X-Factor of **-1.42%**, the Company is proposing a stretch factor (Consumer Dividend) of **15** basis points when inflation exceeds two percent. Unlike the X-Factor, there is not a commonly accepted quantitative methodology for calculating a stretch factor. Instead, regulatory judgment and case precedent play important roles in the specification of the stretch factor. A quantitative approach that has been used to assist in the selection of the stretch factor—in combination with regulatory judgment and precedence—is cost benchmarking analyses. Under a cost benchmarking analysis, the costs of the utility under the PBR plan are compared to the industry costs to determine whether the utility's costs are significantly above, below, or equal to the industry

[3] In 2022, the number of ultimate customers for the total electric industry was 160,161,776. *See* U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report," and Form EIA-861S, "Annual Electric Power Industry Report (Short Form)," https://www.eia.gov/electricity/annual/html/epa_02_01.html. The number of customers accounted for by the 87 companies in the TFP model in 2022 is 97,168,400, which is 60.7% of all electric customers in the U.S.

average costs. We have conducted cost benchmarking analyses, finding that PSNH's costs are close to the electric industry's average costs. We conclude that, based upon our cost benchmarking analyzes, PSNH is an average cost-performing utility, neither a low nor high performing electric company in terms of operating costs.

Although the Company is proposing an official stretch factor of 15 basis points when inflation exceeds two percent, the Company's stretch factor is *effectively* higher than the 15 basis points. Although the X-Factor we calculate is -1.42%, the Company has set the X-Factor at zero with some of the difference being akin to a stretch factor. Moreover, as we discuss below in Section IIB, in a revenue-cap PBR formula, the formula contains an additional component capturing the growth in customers expected during the PBR plan. Without a customer growth factor in the PBR plan, the Company may be unfairly penalized (rewarded) for customer growth (declines). It is commonly accepted that, in the absence of a customer growth factor in the revenue-cap PBR formula, any additional customer growth the Company achieves may be a customer benefit, directly akin to the stretch factor.

All of these reasons—regulatory judgment and precedent; PSNH's cost performance per the cost benchmarking analysis; and the fact that the Company is setting the X-Factor to be zero rather than the -1.42% that we calculate in our X-Factor Study—support the Company's stretch factor proposal.

We discuss the following topics in this report. In Section II, we discuss the economic reasons why PBR is utilized in some jurisdictions and focus on the incentive properties of PBR in general and compared to RoR regulation. We also show the PBR formulas for price-caps, revenue caps and revenue-per-customer caps, highlighting the components that are typically included in the PBR formula and the differences between the formulas depending on what measure the formula caps—*i.e.*, price or revenue.

In Section III, we explain the economic principles that guide PBR, and we derive the X-Factor. We emphasize the importance of the inflation measure in determining the X-Factor formula, the significance of a revenue-cap plan vs. a price-cap plan and how the TFP study is conducted and how the PBR formula differ under each. In the same section, we also discuss the theory and practice of the stretch factor and the proper role of a cost benchmarking analysis.

In Section IV, we present the TFP methodology that we use in our study, discussing our measure of output and inputs in the TFP study, with an explanation of the methodology we use to measure the capital input in the study. We also explain our treatment of customer expenses, which we include in our study, and our approach to inclusion of a share of Administrative and General ("A&G") and general plant ("common costs"), as well as the challenges and limitations presented by inclusion of common costs in an electric-distribution study.

In Section V, we present our results from our electric distribution industry TFP and X-Factor study. We explain the sample selection of 87 electric distribution companies in our study, the period considered, and the data and data sources used for our study. We then discuss the calculation of the output and input indices and present the annual and average TFP results during the period—including the input price growth of the 87 electric distribution companies—and the annual and average X-Factor during the period.

Lastly, in Section VI, we present and explain the statistical cost benchmarking analysis that we conduct to compare PSNH's costs *vis-à-vis* the electric distribution industry's costs. First, we compare PSNH's unit costs to the average unit costs of the electric distribution industry. We then conduct an econometric cost benchmarking analysis where we estimate an econometric cost model—using the same electric distribution industry data we used in our TFP and X-Factor study—and use the model to predict PSNH's costs. A comparison of PSNH's predicted costs to its actual costs is the basis of the cost benchmarking analysis.

C. Qualifications

Dr. Agustin J. Ros is a Senior Managing Director at Ankura Consulting Group ("Ankura") and Adjunct Professor at the International Business School at Brandeis University. He has over 30 years of experience in regulatory economics in energy, telecommunications, and in other public utilities. At Brandeis University he teaches a course on global regulatory and antitrust economics and is an advisor to the Board of the Boston International Arbitration Council.

Dr. Ros is an expert in TFP analysis and performance-based ratemaking as well as in cost of service. He has worked on dozens of TFP studies involving electricity, gas and telecommunications. He worked on the early TFP studies before the Federal Communications Commission and before state PUCs involving the incumbent local telephone companies. His TFP work continued internationally, working on TFP studies in Peru, Canada and Mexico. Dr. Ros was an expert nominated by the Alberta Public Utilities Commission to conduct a TFP study for the electricity and natural gas distributors in Alberta and assisted in developing the TFP methodology and the model that was used and accepted by the Commission in that proceeding. He recently led a TFP, cost benchmarking and stretch factor study on behalf of Hydro-Québec

TransÉnergie before the Régie de l'énergie. He has published academic articles on the topic of TFP and performance-based ratemaking including a recently published study in the *Journal of Regulatory Economics* on cost benchmarking in the electricity sector.

Dr. Ros has filed more than 60 expert reports and testimony before U.S. Federal District Courts, the Federal Communications Commission, the Federal Energy Regulatory Commission, the Canadian Competition Commission, the Canadian Radio and Telecommunications Commission, before U.S. and Canadian public utility commissions (including before the New Hampshire Public Utilities Commission) and the International Chamber of Commerce. Internationally he has filed expert reports in Australia, Bahamas, Barbados, Brazil, Colombia, El Salvador, Guatemala, Honduras, Indonesia, Italy, Mexico New Zealand, Peru, Singapore, Spain, and Trinidad and Tobago.

Dr. Ros has also worked as an economist at the Illinois Commerce Commission and the Federal Communications Commission. At the ICC he was Executive Assistant to the Chairman advising the Chairman on all economic and policy matters before the Commission and was selected to participate in the Federal-State partnership in Telecommunications at the FCC in 1996 where he worked on the economic rules implementing the local competition provisions of the Telecommunications Act of 1996. Dr. Ros is an expert in financial and damage analysis as well as in econometric and statistical analysis and has published his research in peer-reviewed academic and industry journals, such as the *Energy Journal*, *Energy Economics*, *Information Economics and Policy*, *Journal of Regulatory Economics*, *Review of Industrial Organization*, *Review of Network Economics*, *Telecommunications Policy*, and *Info*.

II. Performance-Based Regulation

A. Incentives Under Performance-Based Regulation

Incentive regulation, a form of PBR, is a mechanism for regulating the prices or revenues of public utilities, rather than profits, as is done under CoS/RoR regulation. PBR improves the incentives of the utility for achieving efficiencies and cost savings. It is a replacement framework for CoS/RoR regulation, which, compared to PBR, provides inferior incentives for increasing efficiency and cost savings.

A PBR plan commonly relies on constraining the allowable price—or revenue—changes for a given utility based upon the performance of a group of utilities, such as the productivity growth of a group of utilities. A typical PBR plan rewards a utility that is highly productive relative to the comparison group through higher profits, thus providing stronger incentives to achieve cost efficiencies and higher productivity growth than under CoS/RoR regulation. PBR penalizes a utility that is less productive relative to the comparison group through lower profits, which also provides stronger incentives to improve performance than under CoS/RoR regulation.

The central idea of PBR is to rely on incentives to increase efficiency while reducing regulatory costs to produce just and reasonable rates. PBR can help to improve two types of economic efficiencies:[4]

Productive efficiency: Taking customer demand as given, and meeting that demand at least cost as possible; and

Allocative efficiency: Results when prices that consumers pay for goods and services are aligned with the least-cost mix of current inputs and future cost structure and technology, thereby providing customers with the highest value range of outputs and services.

The main reason why PBR increases productive efficiencies is it loosens the link between a company's actual costs and the prices it can charge customers, with the degree to which that "loosening" occurs dependent on the type of PBR plan implemented by the regulator within applicable legal constraints. In general, productive efficiencies tend to be lower under CoS/RoR regulation due to weaker incentives to reduce costs and increase efficiency. CoS/RoR is viewed as a "cost-plus" form of regulation whereby a firm's prices are a direct function of its underlying costs. An increase in prudently allowed costs may result in the need for a rate case and higher prices for customers. At the same time, under CoS/RoR regulation a utility is required to lower revenues in the event that it lowers its costs. This results in lower incentives to minimize costs.[5]

By contrast, PBR reduces the direct interaction between a utility's realized costs and its allowed rates. If a utility can find ways to meet demand while reducing costs, thereby increasing efficiency, it will keep some or all the cost savings as additional profit. Accordingly, firms operating under a PBR plan have the incentive to pursue those cost savings.

[4] To the extent that it provides more flexibility to introduce new services and/or more attractive rate plans, PBR can also increase dynamic efficiencies.

[5] RoR regulation can provide incentives for reducing costs and increasing productive efficiency when rate case proceedings are infrequent—*i.e.*, through regulatory lag. A firm has an incentive to reduce costs between rate cases because it retains the benefits until the next rate case. The longer the time between rate cases, the greater the incentive for efficiency. However, there are limits to regulatory lag, as there is no *ex-ante* certainty on the length of the lag at the time of embarking on cost-reducing investments and activities because, at any time, the regulated firm can be called in for a rate proceeding.

The potential for superior efficiency incentives and regulatory cost savings depends on several factors. The longer the duration of the PBR plan, the greater the magnitude of efficiency-enhancing effects as the firm has greater incentives to implement longer-term efficiency plans and to keep higher profits for longer periods. Typically, PBR plans can last anywhere from as little as two years to as long as ten years, with longer plans increasing the incentive effects.

Another factor affecting the magnitude of efficiency incentives under PBR is earnings sharing. A PBR plan may include earnings sharing in which the utility returns a share of earnings to customers—through lower prices, refunds, *etc*.—when earnings are above a threshold level. A PBR plan without earnings sharing provides greater incentive effects than plans with earnings sharing, which is effectively a tax on the incremental profits realized as a result of PBR.

PBR plans can include other elements that impact the firm's efficiency incentive effects. These elements include: (1) true-up mechanisms—how efficiency gains during the plan are shared in subsequent plans; (2) off-ramps—the conditions under which the PBR plan reverts to RoR regulation; and (3) whether the plan applies to all the firm's costs or a subset, with remaining costs continued to be regulated in some fashion under RoR, as is the case when a plan contains some type of capital mechanisms.

In addition to potential gains in efficiency and cost savings, there are other potential advantages of PBR. For both the regulator and the utility, PBR can help to reduce the high regulatory and administrative costs and burdens of annual or periodic rate cases. In addition, the utility may prefer being able to exceed the allowed return on equity under PBR if they are able to operate more efficiently than expected. Customers are also likely to benefit from lower rates *than would otherwise have been the case*, as well as increased rate stability and predictability over that expected under RoR regulation.

A potential drawback of the PBR approach is that it is possible that the utility endeavors to lower costs at the expense of service quality. Regulators can address this through additional price or revenue adjustment mechanisms to reflect service quality, such as establishing service-quality metrics with symmetrical monetary incentives for performance above and below threshold levels.

B. Rate Changes Under Performance-Based Regulation

Indexed-based PBR formulas can cap the *prices* at which utilities sell their services and permit the firm to maximize profits, contingent on meeting the price cap on individual services. Alternatively, indexed-based PBR formulas can cap *revenues* instead of prices, either in the form of a cap on overall revenues, or as a cap on per-customer revenues. Indexed-based PBR formulas are usually augmented with other elements to provide additional constraints or latitude to balance the objectives of PBR, for example to ensure that the utility does not unduly benefit from, nor be unduly penalized for, events outside of its control. There are several implementation alternatives for each of these approaches. For example, less formal PBR frameworks may target only some aspects of the utility's costs—*e.g.*, certain O&M expenses or certain capital expenses—while regulating other costs through more traditional RoR means (partial indexing).[6]

The generic formula for an index based PBR price cap formula is in the form:

$$Price_t = \left(Price_{t-1} \times (1 + I_t - X)\right) - CD + Y_t + Z_t + K_t + ESM_t \qquad (1)$$

Where:

Price = the price for an individual product or service

t = the period (year)

I = an inflation factor

X = a productivity factor

CD = a consumer dividend (stretch factor)

Y = a factor for flow through adjustments

Z = a factor for exogenous adjustments (for matters outside the utility's control)

K = a factor for supplemental capital

ESM = an earnings sharing mechanism

Price-capped PBR formulas are usually adopted when the utility is expected to experience significant customer and/or service and product growth over the stay-out period. For example, when PBR was adopted for telephone companies in the 1980's and 90's, price-cap formulas were typically used in recognition of the significant growth experienced in the telecoms sector.

The generic formula for a revenue cap is in the form:

$$Revenue_t = \left(Revenue_{t-1} \times (1 + I_t - X + CG)\right) - CD + Y_t + Z_t + K_t + ESM_t \qquad (2)$$

Where:

[6] For example, Hydro-Quebec TransÉnergie's PBR formula applies only to its non-capital-related expenses.

Revenue = the total annual revenue of the utility

t = the period (year)

I = an inflation factor

X = a productivity factor

CG = a customer growth factor

CD = a consumer dividend (stretch factor)

Y = a factor for flow through adjustments

Z = a factor for exogenous adjustments (for matters outside the utilities control)

K = a factor for supplemental capital

ESM = an earnings sharing mechanism

Revenue-capped PBR formulas limit the change in the allowed overall *revenue* from one year to the next. The revenue capped PBR formula in equation (2) is nearly the same as the price capped PBR formula in equation (1), with one significant difference. The revenue capped PBR formula includes an additional element, CG, a customer growth factor, which accounts for the firm's customer growth rate. The customer growth factor applies to a revenue capped PBR formula whether or not the Company has a revenue decoupling plan. As we discuss below in Section III C, without a customer growth factor in the formula, the firm may be unfairly penalized for any net new customers in the year.

Revenue-capped PBR plans have been adopted when the utility has conservation initiatives or demand side management mechanisms, whereby achieving strong output growth is not a policy or utility objective.

Lastly, the generic formula for a revenue-per-customer cap is in the form:

$$\frac{Revenue_t}{Customer_t} = \left(\frac{Revenue_{t-1}}{Customer_{t-1}} \times (1 + I_t - X)\right) - CD + Y_t + Z_t + K_t + ESM_t \qquad (3)$$

A revenue-per-customer cap PBR formula functions much like the revenue cap discussed above. Instead of limiting the change in the allowed overall revenue from one year to the next, however, it limits the change in a utility's revenue *per customer* on a class-by-class basis. Revenue-per-customer caps are usually adopted when the average revenue-per-customer for most customer classes is expected to grow or decline substantially from one year to the next over the stay-out period. In these circumstances, a revenue-per-cap avoids revenue excesses or shortfalls. A revenue cap PBR formula with a positive or negative customer growth factor, as appropriate, will provide essentially the same revenue as a revenue-per-customer cap.

III. The X-Factor in the "I – X" PBR Formula

A. Derivation of the X-Factor

The primary mechanism by which prices or revenues are constrained in equations (1) through (3), in Section II.B, above, is the "I – X" component. In this section, we discuss the economic principles to consider in determining the X-Factor and we derive the X-Factor formula.

A primary goal of economic regulation is to regulate in a manner such that economic outcomes mimic the outcomes that one would typically observe under competition. In competitive markets, economic profits tend to be zero in the long run. This is the starting point for price and revenue cap regulation. As we demonstrate, the long run zero profit condition under competition implies that average output price equals the cost the firm pays for the inputs needed to produce a unit of that good or service, accounting for the industry's productivity—that is, the efficiency of turning inputs into outputs.

Starting from that basic assumption, the cap used in price-cap regulation is calculated to reflect what we would expect to observe in competitive markets in the long run, *i.e.,* prices are set to equal input prices minus productivity "I – X", where I represents inflation and X represents industry-wide productivity. The "I – X" formula means that average prices for capped goods/services are adjusted for inflation (I), less the expected productivity growth over the relevant term, typically representative of an industry average (X). In essence, the allowed price changes mimic changes in average unit costs. In competitive markets, both I and X are external and outside the control of the firm. Thus, the price-cap formula for the regulated firm — "I" and "X" — should likewise be external and exogenous to the regulated firm.

Below, we present the mathematical derivation of the price-cap index and the X-factor formulation following Bernstein, Hernandez, Rodriguez, and Ros, (2006).[7] We start with the assumption discussed above, that economic profits are zero in the long run, so revenues equal costs. For a generalized firm with n outputs and m inputs, with p_i and q_i

[7] Jeffrey I. Bernstein, Juan Hernandez, Jose Maria Rodriguez, and Agustin J. Ros, "X-Factor updating and total factor productivity growth: the case of Peruvian telecommunications, 1996–2003," *Journal of Regulatory Economics* (2006) 30:316–342, (Berstein *et. al*). This study builds upon the work of Jeffrey I. Bernstein and David M. Sappington, "Setting the X-Factor in Price Cap Regulation Plans," *Journal of Regulatory Economics* (1999) 16:5-26.

denoting the price and quantities of the ith output, and w_j and v_j denoting the price and quantity of the jth input, we can write:

$$0 = R - C = \sum_{i=1}^{n} p_i q_i - \sum_{j=1}^{m} w_j v_j \tag{4}$$

Totally differentiating the expression above yields the following:

$$0 = \sum_{i=1}^{n} p_i q_i \frac{dq_i}{q_i} + \sum_{i=1}^{n} p_i q_i \frac{dp_i}{p_i} - \sum_{j=1}^{m} w_j v_j \frac{dv_j}{v_j} - \sum_{j=1}^{m} w_j v_j \frac{dw_j}{w_j} \tag{5}$$

Next, we make the following definitions, with a dot over a variable x representing dx/x (a small percentage change):

$r_i = p_i q_i / R$ is the revenues share of the ith output.

$s_j = w_j v_j / C$ is the cost share of the *j*th input.

$$\dot{P} = \sum\nolimits_{i=1}^{n} r_i \dot{p}_i \tag{6}$$

$$\dot{W} = \sum\nolimits_{j=1}^{m} s_j \dot{w}_j \tag{7}$$

$$\dot{Q} = \sum\nolimits_{i=1}^{n} r_i \dot{q}_i \tag{8}$$

$$\dot{V} = \sum\nolimits_{j=1}^{m} s_j \dot{v}_j \tag{9}$$

Substituting into equation (5) above and rearranging yields:

$$\dot{P} = \dot{W} - (\dot{Q} - \dot{V}) \tag{10}$$

We note that $\dot{T} = \dot{Q} - \dot{V}$ is the regulated firm's total factor productivity (TFP) *growth* rate, that is, the growth of its outputs less the growth of its inputs. This yields:

$$\dot{P} = \dot{W} - \dot{T} \tag{11}$$

Equation (11) states that if a regulated firm's prices are set initially to ensure zero extra-normal profit, and if the firm's prices are subsequently required to change at a rate equal to the difference between its input price growth rate and its productivity growth rate, then the regulated firm will continue to earn zero extra-normal profit.

If price-cap regulation were to proceed by measuring actual changes in the regulated firm's input prices and productivity, and then by adjusting the firm's output prices accordingly, price-cap regulation would function much like rate-of-return regulation. For this reason, it is common practice to set $\dot{T}$ in equation (11) based upon *industry wide* TFP, rather than the TPF of the firm. For the same reason, it is common practice to set $\dot{W}$ in equation (11) based upon *industry wide* input prices, rather than the input prices of the firm.

B. Relationship Between the Inflation Measure and the X-Factor

How $\dot{W}$—inflation in the "I – X" formula—is set determines the X-Factor formula in a price cap plan. When $\dot{W}$ is a measure of the *industry's* input price inflation, then the *X-Factor is simply* $\dot{T}$, the *industry wide* TFP growth.[8] An industry-specific input price inflation measure captures the inflation in wages, materials, equipment, contractors, *etc.*, that, in this case, the electric distribution industry is likely to experience during the PBR plan.

Creating an industry-specific input inflation measure can be a challenge. For this reason, many price cap plans instead utilize a transparent inflation measure that is to prevail during the forthcoming price cap period. One such measure is the economy-wide GDP-PI, which measures output prices in the economy. Accordingly, when a price cap plan uses an *output* inflation measure, such as economy-wide GDP-PI, the X-factor needs to account for *differences* between economy-wide and industry-wide TFP and input price changes.

To see how, we observe that the relationship in equation (11), above, is true for both the regulated firm in question, as well as the outside economy—as long as economic profits are still zero—and we can also write:

$$\dot{P}^E = \dot{W}^E - \dot{T}^E \tag{12}$$

[8] Exclusive of a possible stretch factor/consumer dividend, which can be added to the X-Factor and is a direct benefit to consumers, acknowledging that the transition from cost-of-service regulation to price-cap regulation should lead to increased efficiencies and increased profits and that the first cut of those benefits could be passed along to consumers.

With the superscript *E* referring to the outside economy. Taking the difference between the firm-specific equation (11) and economy-wide expressions equation (12) and rearranging, we see:

$$\dot{P} = \dot{P}^E - \left[\left(\dot{W}^E - \dot{W}\right) + \left(\dot{T} - \dot{T}^E\right)\right] \tag{13}$$

Labeling the terms in the square brackets as *X*, this yields:

$$\dot{P} = \dot{P}^E - X \tag{24}$$

This expression in equation (14) provides the basic formulation of the price cap regulation when the inflation factor is an economy-wide measure of inflation, such as GDP-PI. It implies that regulated prices should be allowed to rise, "on average, at a rate equal to the rate of the output price inflation ($\dot{P}^E$) less an offset (X)."[9] This offset is the sum of "the difference in input price growth rates between the rest of the economy and the regulated firm ($\dot{W}^E - \dot{W}$)" and "the difference in total factor productivity growth rates between the regulated firm and the rest of the economy ($\dot{T} - \dot{T}^E$)."[10] The output price inflation is usually simplified to "*I*," yielding the familiar "*I – X*."

To summarize, when the inflation factor (I) in a price-cap plan is one that measures the input price inflation of the industry, then the X-factor in the "I – X" formula is the *industry wide* TFP. When an economy-wide output price inflation—such as GDP-PI—is the inflation factor (I) in a price cap plan, the X-factor in the "I – X" formula is the industry-wide *TFP differential*—between the industry and the economy—plus the industry-wide *input price differential*. Table 1, below, summarizes the relationship between the inflation measure and the X-Factor.

Table 1: Inflation Measure and the X-Factor

Inflation Measure in "I – X"	X-Factor in "I – X"
Measure of the electricity distribution industry input price inflation in wages, materials, rents, capital.	X-Factor is the TFP growth of the electric distribution industry.

9 Bernstein *et. al*., op. cit. footnote 7, p. 329.

10 *Id.*, p. 328.

Measure of the economy-wide output price inflation, such as GDP-PI.	X-Factor is the TFP growth *differential* of the electricity distribution industry and the economy *plus* the input price *differential* of the economy and the electric distribution industry.

C. Implications for Revenue-Cap Plans

There are two significant implications when the PBR plan and formula constrains *revenues* through a revenue-cap plan. The first is that it impacts how to conduct a TFP study and can require that the output measure in the TFP study be the number of customers served. We discuss this in Section IV.B.

The second implication is that the revenue-cap formula is slightly different than the price-cap formula, as we discussed in Section II.B—specifically, the revenue-cap formula contains a customer growth factor. Logically, if the regulator limits revenues instead of prices, the revenue cap should include an output growth factor. If this growth factor were not included, the revenue formula could unfairly penalize—or reward—the firm.[11]

We can derive mathematically the inclusion of the customer growth factor in the revenue cap formula based upon the equations in the previous Section. We begin by noting that revenue growth is simply the sum of the output price growth and the output quantity growth:

$$\dot{R} = \dot{P} + \dot{Q} \qquad (35)$$

Substituting (15) into (14) yields the revenue cap formula:

$$\dot{R} = \dot{P}^{E} - X + \dot{Q} \qquad (46)$$

Equation (16) says that under a PBR revenue-cap plan, revenues are permitted to grow at the rate of output inflation ($\dot{P}^{E}$) minus the X-Factor—the same X-Factor as in the price cap formula in equation (14)—*plus* the output quantity growth rate.[12]

[11] Specifically, demand growth results in revenue growth even when prices remain constant. In the absence of a customer growth factor, in the face of positive demand shocks a revenue cap formula would require the firm to lower its revenues—by lowering prices or lowering output—outcomes that are contrary to outcomes in competitive markets.

[12] The X-Factor in equation (16) is conceptually the same as the X-Factor in equation (14), except that, the selection of a revenue-cap plan affects the output measure in the TFP study, as we discuss in

D. The Stretch Factor ("Consumer Dividend")

Both the price and revenue-cap formulas in Section II. B., contain a consumer dividend factor ("CD"), also known as the stretch factor. The stretch factor is a feature in some price and revenue-cap plans adopted by regulators in electricity, natural gas, and telecommunications industries. Inclusion (exclusion) of a stretch factor in the PBR plan results in a higher (lower) X-Factor and, all else equal, lower (higher) rates.

A stretch factor is usually applied to the PBR formula in first generation PBR plans to immediately share *with consumers the efficiency gains from the PBR plan that a utility is* expected to achieve ("low hanging fruit") when first under a new incentive structure. A stretch factor is often applied to an indexed PBR plan—whether a first generation PBR plan or not—to more immediately share some of the annual productivity gains with customers throughout the stay-out period to provide for an equitable sharing of benefits. In both cases, a stretch factor reduces revenue increases annually to provide customers with a direct benefit of the PBR incentives underlying the plan.

In its first price cap proceeding for electricity and natural gas distribution companies in 2012, the Alberta Utilities Commission described the purpose of a stretch factor:

> The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.[13]

In a 2017 decision, the Massachusetts Department of Public Utilities ("MDPU") also described the stretch factor as intended to reflect expected future gains in productivity due to the move from cost-of-service regulation to incentive regulation.[14]

In an early PBR plan, the Ontario Energy Board stated the following about the stretch factor:

> It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess

Section IV.B. The customer growth factor in equation (16) applies to a revenue capped PBR formula whether or not the Company has a revenue decoupling plan.

[13] Alberta Utilities Commission Decision 2012-237, p. 100.

[14] NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy, D.P.U. 17-05 (2017) ("D.P.U. 17-05"), p. 394.

> earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the utility.[15]

In terms of how to estimate the stretch factor, the Alberta Utilities Commission stated:

> As parties pointed out, the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a definitive analytical source like the TFP study represents.[16]

This was a sentiment echoed by the MDPU. In its 2017 decision, the MDPU summarized the position of NSTAR Electric, indicating that the determination of a stretch factor is largely subjective and that there is a lack of quantitative, empirical basis for establishing its magnitude.[17]

As discussed in the companion *PBR Overview* paper, stretch factors in some recent PBR decisions for electric utilities in North America range between 0 and 0.6% (60 basis points), depending on the jurisdiction. In some cases, such as in Alberta, Canada, the stretch factor was based upon regulatory judgment and precedent and not upon a quantitative analysis.

In other cases, a cost benchmarking analysis is conducted that can be used to assist the regulator in its determination of the stretch factor. Under a cost benchmarking analysis, the costs of the utility under the PBR plan are compared to the industry costs to determine whether the utility's costs are significantly above or below the industry average costs. Under this approach, the assumption is that a company's cost performance relative to its peers indicates its ability to achieve incremental efficiency gains under the plan. A company with higher unit costs or unit cost growth relative to its peers may have more ability to cut costs further, which may be accounted for in the stretch factor. Conversely, a company with lower unit costs relative to its peers may have less capacity to cut costs. In combination with regulatory judgment and precedent, a cost-benchmarking analysis can be helpful to the regulator in setting the stretch factor.

15 Ontario Energy Board, EB-2007-0673, "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," September 17, 2008. p.19.

16 Alberta Utilities Commission Decision 2012-237, p. 104.

17 D.P.U. 17-05, p. 395.

It is important to recognize, however, the limits of a quantitative cost benchmarking analysis for determining the stretch factor, as it cannot be a complete substitute for what is ultimately an exercise based on regulatory judgment, as well as regulatory precedent. As mentioned, the central idea and assumption behind the cost benchmarking and comparison approach to the stretch factor is that a firm's current level of costs *vis-à-vis* a comparison group is a relevant factor in determining the *magnitude* of a stretch factor for its PBR plan. Moreover, the belief is that a statistical cost comparison analysis is a good and robust approach to determine whether a firm is operating at an efficient level.

These two central ideas and assumptions behind cost benchmarking have their limits. Cost benchmarking and comparison analysis attempts to estimate the costs of the target firm relative to the broader comparison group, and to base the stretch factor on whether costs for a firm are significantly lower, significantly higher or are not statistically distinguishable from the average. To the best of our knowledge, however, there is no explicit economic theory guiding the actual stretch factor that should apply for an average firm, a superior firm, or an inferior firm. The regulator will still need to apply regulatory judgment and precedent when utilizing the results of a cost-benchmarking analysis.

Furthermore, cost benchmarking analysis can utilize econometric modelling that estimates statistical cost models and compare a utility's actual costs to the costs predicted by the model, with the difference between actual and predicted being a measure of efficiency. It can be a challenge, however, to explicitly account for and control for all the factors that make one firm be far removed from the efficient cost frontier and another firm be closer to the frontier.[18] Some amount of misspecification is likely to occur in any econometric model and can be a factor in explaining a firm's performance *vis-à-vis* other firms' performance.

We have conducted a cost benchmarking analysis that we describe and discuss in Section VI. Our cost benchmarking results are to help inform the regulator and in combination with regulatory judgment and precedent.

[18] It seems that a key assumption of the cost benchmarking and comparison approach is the belief that the statistical model predicts the production possibility frontier, so that a top performer is on the frontier and thus it could make no further improvements. The production possibility frontier refers to all the combinations of output that a firm can produce if it uses all its resources and inputs efficiently. *See* Karl E. Case and Ray C. Fair, *Principles of Economics*, Sixth Edition, (Upper Saddle River, N.J.: Prentice Hall), 2002, p. 30. To the extent that data limitations preclude relevant factors from being included in an econometric cost model, departures from "average" efficiency may well represent the effect of these other factors not being controlled for, rather than failure to minimize cost.

There is an additional important point regarding the stretch factor for the PSNH PBR plan. As discussed in the previous section, and as shown in the PBR formula for a revenue cap in Section II.B., a customer growth component is included in a PBR formula for a revenue cap plan. If the PBR revenue cap formula does not include a customer growth factor, then it is generally accepted that the additional customer growth is a customer benefit, directly akin to the stretch factor.

IV. TFP Methodology

A. Concepts

Productivity is the ratio of the *output quantity* that a company produces to the *input quantity* that it purchases and utilizes to produce its output. It is a measure of how good a firm is at turning inputs purchased into outputs sold.

$$Productivity = \frac{Outputs}{Inputs} \quad (57)$$

Productivity *growth* provides a measure of performance *over time*. TFP and X-Factors in a PBR plan use productivity growth as the basis for constraining rates or revenues, as demonstrated in Section III.A above. Productivity growth is defined as:

$$Growth\ in\ Productivity_t = Output\ growth_t - Input\ growth_t \quad (68)$$

Total Factor Productivity growth is a productivity measure that comprises all a firm's inputs, while a productivity measure that uses multiple, but not necessarily all inputs, is Multi-Factor Productivity.

As is common in productivity studies, we use an indexing approach to combine multiple output and input quantities into a single output and input index. In this study, we use a chain-weighted Törnqvist-Theil indexing methodology.[19] For example, equation (19) below is the formula we use for combining the input quantities in our TFP study.

$$ln\left(\frac{Input_t}{Input_{t-1}}\right) = \sum_j \frac{1}{2} \times \left(share_{j,t} + share_{j,t-1}\right) \times ln\left(\frac{Input\ Qty\ Index_{j,t}}{Input\ Qty\ Index_{j,t-1}}\right) \quad (19)$$

Where:

[19] *See* Michael Denny, Melvyn Fuss and Leonard Waverman, "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," p. 188, in *Productivity Measurement in Regulated Industries*, edited by Thomas G. Cowing and Rodney E. Stevenson, Academic Press, 1981.

$share_{j,t}$ = cost share of input component *j* in year *t*.

$Input\ Qty\ Index_{j,t}$ = Quantity index for component *j* in year *t*.

If more than one measure of output is used in the TFP study we use a similar formula with respect to outputs, specifically:

$$ln\left(\frac{Outputs_t}{Outputs_{t-1}}\right) = \sum_j \frac{1}{2} \times \left(share_{j,t} + share_{j,t-1}\right) \times ln\left(\frac{Output\ Qty\ Index_{j,t}}{Output\ Qty\ Index_{j,t-1}}\right) \qquad (70)$$

Where:
$share_{j,t}$ = revenue or cost elasticity share of the output component for *j* in year *t*.

$Output\ Qty\ Index_{j,t}$ = Quantity index for output component *j* in year *t*.

The growth in the total/multi factor productivity index is the difference in the growth of the output and input indices, respectively.

With respect to inputs, a firm utilizes many different types of inputs, and it is common in productivity studies to categorize them into three broad categories: capital, labor, and materials, rents, and services—the latter often referred to as (“MR&S”). Labor and MR&S expenses, collectively operation and maintenance (“O&M”) expenses, are readily available from FERC Form 1 data. We obtain quantity indices for these two inputs by deflating their respective expenses by an appropriate input price index—a labor input price index and an MR&S input price index. We provide the data used and the details of this approach in Section V.C. We discuss capital in Section IV.C, below.

B. Output Measure

With respect to outputs in a TFP study, in the context of electric utilities, outputs typically are the number of customers that a utility serves, the total MWh delivered or the peak MW demand, depending on the industry studied—whether electric distribution or electric transmission—and depending on the *type* of PBR plan.

When the PBR plan is a price-cap plan—where prices are constrained in the I – X formula—appropriate measures of output to use in the TFP study are associated with the billing units that generate sales which can, in theory, include all three output concepts—customers, MWh and MW. In practice, in electricity distribution TFP studies where the PBR plan is a price-cap plan, the output measure commonly used has been MWh *or* the number of customers *or* a combination of the two output measures, if feasible.

When the PBR plan is a revenue-cap plan—whether a revenue cap or a revenue per customer cap—the appropriate measure of output to use in the TFP study is the number of customers, a fact that is mathematically derived as follows.

The relationship between revenue growth, revenue per customer growth and customer growth is given below in equation (21), where $\dot{R}$ is revenue growth, $R\dot{P}C$ is revenue per customer growth, and $\dot{C}ustomers$ is customer growth.

$$\dot{R} = R\dot{P}C + Cust\dot{o}mers \qquad (21)$$

Recognizing that under competition revenue equals costs—implying revenue and cost growths are equal—and rearranging terms in (21) results in equation (22) where $\dot{C}$ is cost growth.

$$R\dot{P}C = \dot{C} - Cust\dot{o}mers \qquad (22)$$

Further recognizing that the growth in costs is equal to the growth rate of *input prices* plus the growth rate of *input quantities* results in equation (23) where $\dot{W}$ is input price growth and $\dot{Q}$ is input quantity growth.

$$R\dot{P}C = \dot{W} + \dot{Q} - Cust\dot{o}mers \qquad (23)$$

Recognizing that $\dot{C}ustomers$ (output growth) minus $\dot{Q}$ (input growth) is TFP growth, results in equation (24), where $T\dot{F}P^{Customer}$ represents TFP growth where the unit of output measure is number of customers.

$$R\dot{P}C = \dot{W} - T\dot{F}P^{Customer} \qquad (24)$$

Equation (24) shows that for a revenue per customer cap plan, the TFP utilizes customers as the measure of output. The same conclusion applies to a revenue cap plan but with one difference. Solving for $R\dot{P}C$ in equation (21) and substituting it into equation (24) results in:

$$\dot{R} = \dot{W} - T\dot{F}P^{Customer} + Cust\dot{o}mers \qquad (25)$$

Equation (25) shows that for a revenue cap plan, TFP utilizes customers as the measure of output *and* requires that customer growth be added as part of the PBR formula. In the absence of a customer growth component in the PBR formula, the customer growth rate is absorbed into and becomes part of the Stretch Factor.

C. Capital Measure

Measuring capital quantity and capital input price is the more challenging part of a TFP study. We use the *Perpetual Inventory Method* for measuring capital in our TFP study. At any point in time there are varying vintages of capital that a company uses, some purchased recently and others that have been in use for much longer periods. It is important to measure and compare the capital stock in such a way as to account for the capital services it produces and the corresponding annual value over time. Measuring the reproduction cost of distribution plant expressed in constant dollars permits such a comparison. The *Perpetual Inventory Method* is one common method of measuring the reproduction cost of plant and equipment (capital) expressed in constant dollars. It accounts for the presence of different vintages of capital stock at any given point in time.[20]

We also use the *One-Hoss Shay Method* in our TFP study to measure capital quantity and the flow of capital services that a unit of capital provides over time. *One-Hoss Shay* assumes that the asset produces a relatively constant flow of capital services throughout its life. Under O*ne-Hoss Shay*, the key assumption is that over the life of the asset, the services that a unit of capital provides do not generally decline.[21] This means that an asset would generally yield a constant level of capital services throughout its useful life and then collapse in a heap. A light bulb and a chair are common examples. Charles R. Hulten, a well-known expert on capital, stated:

> "Of these patterns, the one hoss shay pattern commands the most intuitive appeal. Casual experience with commonly used assets suggests that most assets have pretty much the same level of efficiency regardless of their age— a one year old chair does the same job as a 20 year old chair, and so on."[22]

With respect to the capital price—*i.e.*, the equivalent of what wages are to the labor input—a challenge is that capital prices are not readily observable in the market, unlike labor where the wage is the result of labor market competition and labor demand and supply dynamics. This is especially the case for the types of assets involved in the

[20] L.R. Christensen and D.W. Jorgenson (1969), "The Measurement of U.S. Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, No. 4, December, pp. 293-320.

[21] A one-hoss shay is a light, covered carriage drawn by a horse and is immortalized in a poem by Oliver Wendell Holmes Sr. "The Deacon's Masterpiece: or the Wonderful "One-Hoss-Shay. A Logical Story."

[22] *See* Charles R. Hulten, "The Measurement of Capital," p. 124, *Fifty Years of Economic Measurement*, E.R. Berndt and J.E. Triplett (eds.), Studies in Income and Wealth, (The National Bureau of Economic Research, Chicago: The University of Chicago Press), Volume 54, 1991.

electricity distribution business.[23] Unlike commercial real estate, for example, where both the buildings and space within buildings is bought, sold, and rented, there is no readily available secondary rental market for electricity distribution assets that we can observe. Measuring the "price" of capital in a TFP study thus requires that we *impute* a "rental price" of capital and that it measures the "opportunity cost" to the firm of holding a unit of capital.[24]

These three capital concepts—*Perpetual Inventory Method*, *One-Hoss Shay*, and the *Capital Rental Price*—are interrelated. It is important to measure these capital concepts consistently, in such a way as to account for the capital services it produces and its monetary value over time.

Capital measurement is based on three integral components: annual capital cost (annual capital expenses), capital quantity (services), and capital price ("rental" rate for the capital services). These components relate to each other as follows:

$$Capital\ Cost_t = Capital\ Quantity\ Index_t \times Capital\ Price\ Index_t \tag{26}$$

Measuring the capital quantity in a TFP study requires two steps. The first is to calculate the capital quantity (or capital stock) in the *benchmark year*.[25] The second is the calculation of capital quantity for every subsequent year.

The benchmark year refers to the first year for which capital information is available. For the sample of distribution companies, the first year of readily available data from the FERC is 1988. We calculate the capital stock in the benchmark year by deflating the benchmark year plant in service by a weighted average electricity capital construction cost index, the Handy-Whitman index.[26] *One-Hoss Shay* follows the following formula for calculation of the benchmark year capital stock:

$$Benchmark\ Capital\ stock = \frac{Gross\ Plant\ in\ service_{Benchmark\ year}}{\sum_{i=1}^{s}\left(i \times \left(\frac{P_{Benchmark-s+i}}{\sum_{i=1}^{s} i}\right)\right)} \tag{27}$$

23 The annual capital price is similar to an annual rent charged for space in a building.

24 The use of a firm's capital assets for a year comes at the "opportunity cost" of not employing the capital assets—or the value of the capital—in the next best alternative. The rental price of capital is that "opportunity cost".

25 Continuing the building analogy, if rental buildings are bought, sold, and rented on a square-foot basis, the benchmark capital stock is analogous to the number of square feet in a building in the year in which reliable data became available.

26 The Handy-Whitman Index provides cost trends for different types of utility construction published by Whitman, Requardt and Associates.

Where *P* is the electricity capital construction cost index for the respective utility sample and *s* is the distribution asset life. The denominator in the formula above weighs the construction cost index going back over the asset's service life. We use 35 years for *s* in our study.

The second step in measuring the capital quantity in a TFP study is the calculation of capital quantity for every subsequent year (*i.e.*, after the benchmark year). *One-Hoss Shay* implies that a unit of capital provides the same level of capital services over the entirety of its useful life until it is retired. The formula for the capital quantity index under *One-Hoss Shay* is:

$$Captial\ Qty\ Index_t = Capital\ Qty\ Index_{t-1} + \frac{Gross\ Additions_t}{P_t} - \frac{Gross\ Retirements_t}{P_{t-s}} \qquad (28)$$

The capital quantity index is created by adding deflated gross additions and subtracting deflated gross retirements from the previous year's quantity index, where retirement assets are deflated by the index from the year when the assets came into service. Under *One-Hoss Shay*, the formula does not account for depreciation as a one-year-old unit of capital provides the same capital services as a ten-year old unit of capital.

With respect to the capital price index in equation (26)—*i.e.*, the "price" of capital, the opportunity cost/rental price of owning a unit of capital—*One-Hoss Shay* implies a certain rental price formula. With *One-Hoss Shay*, the asset provides the same amount of capital services each year over the life of the asset. Therefore, the annual payments are constant, apart from the effect of inflation in the purchase price of new assets. To justify the purchase of the new asset, the discounted sum of the annual "rental" payments—adjusted for asset inflation—would equal the purchase price.[27] Specifically, the "rental" price of capital under *One-Hoss Shay* is:

$$P_t = \left(\frac{1-k-uz}{1-u}\right) \times \frac{(r-i)}{(1+r)} \times \left[1-\left(\frac{1+i}{1+r}\right)^s\right]^{-1} \times HW_{t-1} \qquad (29)$$

[27] Equation (29) is derived from the basic principle that the purchase price of an asset is equal to the discounted cash flows from that asset.

Where: k = investment tax credit rate,[28] u = corporate profits tax rate,[29] z = present value of the depreciation deduction on new investment, r = cost of capital,[30] i = expected inflation rate over the lifetime of assets,[31] s = asset lifetime,[32] HW_{t-1} = Handy-Whitman index in the prior year.

The first term in the above formula accounts for both the tax benefit derived from owning depreciable capital assets and the income tax owed as a result. The tax benefit issue captures the idea that being able to deduct tax depreciation lowers the price of an asset—*e.g.*, if you buy something for $100, it costs less because you get some of the $100 back in lower taxes. The second term factors in the cost of capital return over time and is a measure of the foregone return, offset by appreciation—change in HW.[33] For the cost of capital, we assume the average of the cost of debt[34] and the authorized return on equity (ROE).[35] We calculate the present value of the depreciation deduction on new investment as:

$$z = \frac{2}{T \times (T+1)} \times \sum_{i=1}^{T} (T+1-i) \times \left(\frac{1}{1+R}\right)^{i} \tag{30}$$

Where: R = rate of return for discounting depreciation deductions, T = tax lifetime of asset. We use a value of 0.10 for R and a value of 23 years for T, which gives a value of 0.511 as per the above formula.[36]

28 There has been no general investment tax credit for small business in the US over this sample period of this study.

29 Internal Revenue Service, Statistics of Income Historical Table 24.

30 For the cost of capital, we assume the average of the cost of debt and the authorized return on equity (ROE).

31 Calculated using the yield on 30-year treasury bonds from US Department of the Treasury and CPI-U figures from the US Bureau of Labor Statistics.

32 We assume an asset service life of 35 years.

33 W. Erwin Diewert, “Measuring Capital,” National Bureau of Economic Research Working Paper 9526, February 2003, formula 44, p. 35.

34 The cost of debt for each company is calculated from FERC Form 1 as the ratio of interest on long-term debt to total long-term debt: Total long-term debt: FERC Form 1, page 112, line 24, Interest on long-term debt: FERC Form 1, page 117, account 427, line 62c.

35 Rates of authorized return on equity are obtained from a rate case tracker compiled by Regulatory Research Associates (RRA) from SNL. *See* “Rate Cases – Pending and Past.” For companies that do not have ROE information for a given year(s), we extend the most recently available ROE until the next available rate case. If a company has an authorized ROE of zero, we treat it as a “missing” entry and carry over the most recent available ROE.

36 The formula for the depreciation benefit is based on the sum of year depreciation and is an accelerated depreciation method. We performed sensitivities for the calculation of the present value of

D. Treatment of Customer-Related Expenses

Customer-related expenses include expenses in several FERC accounts including customer accounts (meter reading, customer records and collection), customer service and information accounts, and sales accounts. Customer-related expenses are not included in the FERC's distribution accounts, they are in separate accounts. Nevertheless, customer-related expenses are relevant for an electric distribution TFP study since they include essential activities to provide electric distribution services, such as measuring usage and billing activities. Customer account expenses can be entirely assigned and used in the distribution TFP study without the need to use an allocation factor. Accordingly, we include customer-related expenses in our TFP study.[37]

E. Treatment of Common Costs

Common costs refer to Administrative and General ("A&G") expenses such as human resources, legal, executive, and planning. Common costs also refer to General Plant, consisting of offices, furniture, computers, transport. A&G and General Plant cannot be directly assigned to different operating divisions of the electricity business—*i.e.*, distribution, transmission, and generation. In RoR proceedings, allocation factors are utilized to assign A&G and General Plant to the different electricity businesses to determine the costs to provide distribution, transmission, and generation services.

Common costs are avoidable only if the firm ceases operation and economic costing theory by itself does not provide an optimal and generally accepted methodology to allocate common costs to different operating divisions in a vertically integrated electricity firm. There is simply no economically correct way of allocating common costs to the electricity distribution business in a TFP study. Nevertheless, we have utilized typical allocation methodologies in RoR proceedings to assign a portion of A&G and General Plant to the distribution business and have included it in our TFP study to include all the types of costs that are part of the distribution revenue requirement in a typical RoR proceeding.[38]

depreciation deduction, based on the depreciation schedules published by the IRS for capital assets, US IRS Publication 946, "How to Depreciate Property," Appendix A, Table A-1. The US IRS provides depreciation tables for property on a 3-year to 20-year basis. We used 15-year and 20-year recovery periods as most appropriate for distribution and company-specific cost of capital to determine company specific depreciation deduction estimates. We did not find our TFP results particularly sensitive to this latter approach.

[37] *See* Appendix I for the customer-related FERC accounts we include in our TFP study.

[38] We examined the impact of alternative approaches such as unilaterally selecting different shares of general plant costs (*e.g.*, 50%) to recover from distribution and excluding A&G expenses. The TFP results were not particularly sensitive to these changes.

V. Electricity Distribution Industry TFP and X-Factor

A. Companies Included and Period of Study

The X-Factor in a PBR plan utilizes *the industry* TFP—in this case the electric distribution industry TFP—not the TFP of the utility whose rates/revenues are being constrained under the PBR formula. Setting an X-Factor based on the industry TFP ensures that the X-Factor is exogenous, is outside the control of the firm, and that the link between the utility's own costs and allowed prices is broken—resulting in improved incentives for efficiency. Recall this is the basis for the increased efficiency incentives under PBR *vis-à-vis* RoR regulation.

For our electricity distribution industry TFP study, we use data from the FERC and the EIA.[39] FERC regulates interstate electric transmission and natural gas and oil pipelines. As such, electric utilities are required to submit regulatory financial accounts to the FERC on an annual basis by filling out Form 1. This repository is publicly available and published by the FERC.[40] We use FERC Form 1 data for metrics on labor, MR&S, and capital. For the number of customers, we use data from the EIA. In Appendix I, we provide the metrics used in the TFP study and the corresponding data sources.

For our electric distribution industry TFP study, we use 87 U.S. electricity distribution companies. We include the list of the 87 companies in Appendix II. Our general approach for selecting a sample of electricity distribution companies is to select as many companies as possible, governed by data constraints. Productivity growth can exhibit significant volatility at the individual firm level over time and the selection of a large sample of companies can help reduce that volatility.

We use the period 2000 – 2022 for our TFP study, for a total of twenty-three years of data. The capital-intensive and "lumpy" nature—as well as the long asset lives—of electricity distribution implies that productivity growth is cyclical, can be volatile and

[39] U.S. and Canadian regulators have used FERC Form 1 data to calculate TFP in electric distribution and transmission. *See*, for example, D.P.U. 17-05. The Alberta Public Utilities Commission used U.S. distribution companies in TFP studies in 2012, 2016 and 2023 for use in setting an X-factor. *See* Alberta Utilities Commission Decision 2012-237, 2014-D01-2016 and 27388D-01-2023.

[40] Form 1 for electric utilities are available going back to 1994 on the FERC website: https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-1-electric-utility-annual. FERC releases Form 1 data in a format that is not readily usable. Additionally, a significant amount of work goes into processing the data into a clean, usable format. Some third-party vendors process the raw FERC Form 1 data and make it available for use via a subscription service. Our primary data source for this study uses the processed FERC Form 1 data released by SNL Financial, a financial analytics company, which is a part of Standard & Poor's (S&P) Global Market Intelligence.

significantly fluctuate year to year. Selecting a sufficiently long period is necessary to capture the cyclical, long-run TFP trends in the industry.

B. Output Index

For the reasons discussed in Section IV.B, we use number of customers as the measure of output in our TFP study. We use data from the EIA that captures both bundled customers and delivery customers that the distribution utility serves.[41] Since the advent of retail electricity competition in the late 1990s and early 2000s in some states, such as in New Hampshire, an electricity distribution company provides either bundled service—providing both distribution and energy services through a default service to the customer—or delivery services only to the customer. When the electricity distribution company provides the delivery services, a competitive retail electricity company provides the energy services. Both bundled and delivery only customers are relevant for our electricity distribution TFP study.

We calculate the output (customer) growth rate for each company and each year in the sample. We calculate the average output (customer) growth for a given year as an average of the output (customer) growth rate of all companies for that given year, weighed by each company's output (customer).

C. Input Index

In our study, O&M consists of the labor and the non-labor (MR&S) expenses included in the FERC's electricity *distribution* accounts.[42] For the reasons discussed in Section IV.D, we also include the labor and MR&S expenses included in the FERC's *customer-accounts*, such as customer accounts, customer service and information account, and sales account. Customer account expenses are not included in the FERC's distribution accounts, they are in separate accounts. Nevertheless, the expenses are relevant for an electric distribution TFP study since they include essential activities to provide electric distribution services, such as measuring usage and billing activities. Customer account expenses can be assigned directly and used in the distribution TFP study without the need to use an allocation factor.[43]

41 *See* Appendix I for a list of all the specific FERC accounts used in the TFP Study.

42 *Id*.

43 We also include a share of A&G expenses in our study as discussed in Section IV.E.

LABOR

The labor *quantity* index provides a measure of the labor services that utilities "consume" for distribution services every year. Every utility reports the total expenses of labor in the FERC Form 1. We include labor expenses that are in the distribution accounts, in the customer accounts, and a share of the labor expenses in the A&G account. FERC also differentiates labor expenses between operations and maintenance wage and non-wage expense. The labor expense in our TFP study is the sum of operations wages and maintenance wages.

We define the quantity index for labor as the ratio of the total wages paid and a labor price index—*i.e.*, we calculate deflated wages. For the labor price index, we utilize the Employment Cost Index (*see* Appendix I). We then define the labor quantity index as the ratio of total distribution O&M labor expenses to the labor price index.

$$Labor\ Quantity\ Index_t = \frac{Total\ Distribution\ Payroll_t}{Labor\ Price\ Index_t} \tag{31}$$

Equation (31) includes the payroll associated with the customer accounts as well as a share of the A&G payroll.

MATERIALS, RENTS, & SERVICES

Utilities in the U.S. do not report MR&S—non-wage O&M expenses. As is standard in TFP studies, we define MR&S expenses as O&M expenses *net* of labor expenses—that is, we subtract labor expenses from total distribution O&M expenses to arrive at MR&S expenses. Specifically, we define MR&S expense as:

$$MR\&S\ Expenses_t = Total\ Distribution\ O\&M_t\ - Total\ Distribution\ Payroll_t \tag{32}$$

We obtain the MR&S quantity index by deflating MR&S expenses by a price index. We use the GDP-PI as the MR&S price index. We then define the MR&S quantity index as the ratio of the total distribution MR&S expenses to the MR&S price index.

$$MR\&S\ Quantity\ index_t = \left(\frac{MR\&S\ Expenses_t}{MR\&S\ Price\ Index_t}\right) \tag{33}$$

Equation (33) includes the MR&S associated with the customer accounts, as well as a share of the A&G MR&S.

CAPITAL INDEX

As elaborated in detail in Section IV.C, we use *One-Hoss Shay* for capital quantity, flow of capital services and rental price. We use gross investment in 1988 as the benchmark year for the initial capital stock calculation.[44] We calculate the capital stock in subsequent years by adding constant dollar plant additions and subtracting constant dollar plant retirements. We use the following data to arrive at the capital quantity index for any given year: Gross distribution plant in service, distribution plant additions, distribution plant retirements, and a price index for utility construction costs.[45]

COMBINED INPUT INDEX

Once we calculate the quantity indices for each input component—labor, MR&S, and capital—we combine them using a chain-weighted Törnqvist-Theil indexing methodology to provide the growth of a single input index. The growth rate of the combined input index is:

$$ln\left(\frac{Input_t}{Input_{t-1}}\right) = \sum_j \frac{1}{2} \times \left(share_{j,t} + share_{j,t-1}\right) \times ln\left(\frac{Input\ Qty\ Index_{j,t}}{Input\ Qty\ Index_{j,t-1}}\right) \quad (84)$$

Where:
$share_{j,t}$ = cost share of input component *j* in year *t*
$Input\ Qty\ Index_{j,t}$ = Quantity index for component *j* in year *t*

The cost share for each component is the respective components' expenses as a percentage of the total input expenses. For example, we calculate the cost share for labor each year as:

$$Labor\ Cost\ Share_t = \frac{Labor\ O\&M\ Expenses_t}{Labor\ O\&M\ Expenses_t + MR\&S\ Expenses_t + Capital\ Expenses_t} \quad (95)$$

We calculate the input growth rate for a given year as a weighted average of the growth rate of the combined input index for all companies for that given year, weighted by a measure of the output quantity metrics.

Similarly, the annual growth rate for the combined *input price index* is:

44 *See* Section IV.C for the formula we use for the benchmark year as well as for subsequent year additions and retirements. We use an average service life of 35 years.

45 As discussed in Section IV.E, we include a share of general plant and follow the same capital methodology as for the distribution plant with the exception that we use an average service life of 16 years and utilize GDP-PI rather than HW for the general price index.

$$ln\left(\frac{Input\ Price_t}{Input\ Price_{t-1}}\right) = \sum_j \frac{1}{2} \times \left(share_{j,t} + share_{j,t-1}\right) \times ln\left(\frac{Input\ Price\ Index_{j,t}}{Input\ Price\ Index_{j,t-1}}\right) \quad (106)$$

Where $Input\ Price\ Index_{j,t}$ refers to the input price index for component *j* in year *t.* The combined input price index is a metric that we use in our calculation of the X-Factor in a revenue cap plan where the I in I - X is the economy-wide output price inflation.

D. TFP Growth Study Results

Table 2, below, presents the results of our electric distribution industry TFP growth study for the 2000 – 2022 period. TFP growth during the period averaged **-0.26%** with a standard deviation of 1.87%. The electric distribution industry's output growth during the period averaged **1.03%** with a relatively low standard deviation of 0.76% indicating that customer growth, the measure of output in our study, has been relatively stable during the period. The electric distribution industry's input growth during the period averaged **1.29%** with a standard deviation of 1.37%.

Table 2 also shows the electric industry input price growth during the 2000 – 2022 period, which averaged **3.39%** with a standard deviation of 3.96%. We use the electric industry input price growth during the period as one component in the calculation of the X-Factor below.

Table 2: Electric Distribution Industry TFP Growth, 2000 - 2022

Year	Growth of Output Index	Growth of Input Index	Growth of TFP Index	Growth of Input Price
2001	3.91%	-2.04%	5.94%	5.42%
2002	1.11%	0.40%	0.72%	2.12%
2003	0.58%	1.30%	-0.72%	4.64%
2004	1.19%	-1.61%	2.80%	0.07%
2005	1.39%	0.29%	1.10%	7.50%
2006	1.28%	1.33%	-0.05%	2.92%
2007	1.80%	2.03%	-0.23%	6.91%
2008	0.65%	0.56%	0.09%	10.59%
2009	0.14%	1.27%	-1.13%	7.32%
2010	0.41%	2.87%	-2.45%	0.27%
2011	0.19%	2.46%	-2.27%	4.62%
2012	0.51%	0.99%	-0.48%	8.89%
2013	0.88%	0.51%	0.37%	-1.55%
2014	0.49%	1.56%	-1.07%	2.85%
2015	0.80%	0.81%	-0.01%	5.42%
2016	0.91%	1.55%	-0.63%	2.96%
2017	0.96%	3.71%	-2.75%	-1.11%
2018	1.02%	2.76%	-1.74%	-3.56%
2019	0.93%	2.53%	-1.60%	6.11%
2020	0.99%	1.89%	-0.90%	4.74%
2021	0.99%	0.57%	0.42%	2.09%
2022	1.43%	2.57%	-1.14%	-4.63%
2001 - 2022	***1.03%***	***1.29%***	***-0.26%***	***3.39%***

E. X-Factor Results

As explained in Section III.B, when the inflation measure in the PBR formula is GDP-PI, as PSNH is proposing in this proceeding, the X-Factor formula is the TFP growth *differential* of the electric distribution industry and the economy *plus* the input price *differential* of the economy and the electric distribution industry. We show again here for convenience the X-Factor formula derived in Section III.B:

$$\dot{P} = \dot{P}^{E} - \left[\left(\dot{W}^{E} - \dot{W}\right) + (\dot{T} - \dot{T}^{E})\right]$$

Where the terms in the square brackets are the X-Factor when inflation is an economy-wide measure of inflation, GDP-PI. The formula implies that regulated prices should be allowed to rise, "on average, at a rate equal to the rate of the output price inflation ($\dot{P}^E$) less an offset (X)."[46] This offset is the sum of "the difference in input price growth rates between the rest of the economy and the regulated firm ($\dot{W}^E - \dot{W}$)" and "the difference in total factor productivity growth rates between the regulated firm and the rest of the economy ($\dot{T} - \dot{T}^E$)."[47]

The electric industry TFP and input price growth are contained in Table 2, above. Data on the economy-wide (U.S.) TFP growth is readily available from the U.S. Department of Labor and economy-wide (U.S.) input price growth can be readily calculated using economy-wide (U.S.) TFP growth and GDP-PI data from the U.S. Bureau of Economic Analysis.

Putting together all the components of the X-Factor formula, Table 3, below, presents the results of our electric distribution industry X-Factor growth study for the 2000 – 2022 period. The X-Factor for the electric distribution industry averaged **-1.42%** during the period, with a standard deviation of 4.82%. During the period, economy wide TFP growth average **0.77%** with a standard deviation of 1.23%, as compared to **-0.26%** for the electric distribution industry. Input prices in the economy grew at an average rate of **3.01%** with a standard deviation of 1.75%, compared to **3.39%** for the electric distribution industry.

The results in Table 3 indicate that a revenue-cap PBR plan for an electric-distribution company that has just and reasonable going-in rates and has a PBR formula that results in annual allowed revenue changes in years two, three and four of **GDP-PI + 1.42%,** mimics the outcomes that one would observe under competition, while remaining "just and reasonable," consistent with applicable ratemaking standards.

46 Bernstein *et. al*., op. cit. fn.7, p. 329.

47 *Id*., p. 328.

Table 3: Electric Distribution Industry X-Factor Growth, 2000 – 2022

Year [A]	Distribution TFP [B]	US TFP [C]	Distribution Input Price [D]	US Input Price [E]	X-Factor [F]
2001	5.94%	0.49%	5.42%	2.80%	2.83%
2002	0.72%	1.97%	2.12%	3.47%	0.09%
2003	-0.72%	2.35%	4.64%	4.35%	-3.35%
2004	2.80%	2.39%	0.07%	5.06%	5.40%
2005	1.10%	1.45%	7.50%	4.58%	-3.28%
2006	-0.05%	0.31%	2.92%	3.42%	0.14%
2007	-0.23%	0.18%	6.91%	2.89%	-4.43%
2008	0.09%	-0.88%	10.59%	1.00%	-8.62%
2009	-1.13%	0.34%	7.32%	1.00%	-7.79%
2010	-2.45%	2.64%	0.27%	3.84%	-1.53%
2011	-2.27%	-0.49%	4.62%	1.57%	-4.82%
2012	-0.48%	0.58%	8.89%	2.45%	-7.51%
2013	0.37%	0.64%	-1.55%	2.37%	3.64%
2014	-1.07%	0.55%	2.85%	2.29%	-2.18%
2015	-0.01%	0.87%	5.42%	1.74%	-4.56%
2016	-0.63%	-0.09%	2.96%	0.87%	-2.63%
2017	-2.75%	0.60%	-1.11%	2.42%	0.18%
2018	-1.74%	0.71%	-3.56%	3.00%	4.11%
2019	-1.60%	1.09%	6.11%	2.77%	-6.03%
2020	-0.90%	-0.59%	4.74%	0.76%	-4.29%
2021	0.42%	3.52%	2.09%	8.09%	2.90%
2022	-1.14%	-1.65%	-4.63%	5.41%	10.55%
2001 - 2022	***-0.26%***	***0.77%***	***3.39%***	***3.01%***	***-1.42%***

Sources and Notes:
[B]: Author's TFP Model.
[C]: U.S. Department of Labor, Bureau of Labor Statistics, Total Factor Productivity for the Private Business Sector, Series ID MPU4900012 (02), https://www.bls.gov/productivity/home.htm
[D]: Author's TFP Model.
[E]: The US input price growth is defined as the sum of the growths of the US TFP and the GDP-PI.
[F] = ([B] – [C]) + ([E] – [D])

VI. Stretch Factor and the Cost-Benchmarking Analysis

A. Unit Cost Analysis

The objective of a cost benchmarking analysis for PSNH is to provide evidence on PSNH's cost efficiency to assist in the selection of a stretch factor. As discussed in Section III.D, while regulatory judgment and precedent play the key roles in the selection of a stretch factor, cost-benchmarking results can be useful in that selection. Some regulators have used a firm's cost efficiency—as determined by the results of a cost benchmarking analysis—to assist in the selection of the stretch factor, with higher (lower) stretch factors for less (more) efficient firms. We conduct two statistical cost benchmarking analyses—a unit cost analysis and an econometric cost benchmarking analysis. We discuss our unit-cost analysis in this section.

We use data from our electric industry TFP study to calculate the unit costs of the different utilities in our sample, including PSNH. We then compare PSNH's unit costs to the industry average unit costs to determine whether PSNH's unit costs are above or below the industry's average unit costs. We calculate unit costs by first taking the sum of labor, MR&S and capital costs—*i.e.*, total costs—and dividing by the overall price index to arrive at *real* total costs. We then divide each company's real total costs by the company's number of customers to arrive at real unit costs. We do this for each company and each year.

The results are contained in Table 4, below. PSNH's annual unit costs during the period 2000 – 2022 averaged $332.62 with a standard deviation of $32.26.[48] The electric industry average unit cost during the same period was $323.16, with a standard deviation of $84.55. Overall, the results in Table 4 indicate that PSNH's unit costs during the period were close to the electric industry average, only 2.93% higher, indicating that based upon a unit-cost benchmarking analysis PSNH is an average cost performer.

[48] The unit costs are average costs over the entire period and are real costs, *i.e.*, total actual costs divided by a price index. In addition, the capital cost in a TFP study is not the same as the capital costs resulting from a RoR proceeding.

Table 4: Unit-Cost Comparison between PSNH and the Industry, 2000 – 2022

	Mean	Std. Dev	Min	Max
PSNH	332.62	32.26	283.73	386.94
Full Sample of Utilities	323.16	84.55	131.73	765.60
% Difference	2.93%			

Notes:
[1] Unit Cost is calculated as Real Cost (where Real Cost is Total Input Costs divided by the Input Price Index) divided by Total Customers.
[2] PSNH is not included in the summary statistics for the full sample of utilities.

B. Econometric Cost Benchmarking Analysis

For our second cost-benchmarking analysis, we estimate econometric cost models that explain the real total costs of a utility—the dependent variable—as a function of a set of independent variables that we believe affect a utility's real total costs. We use the estimated econometric model's parameters to predict PSNH's real total costs and compare PSNH's *predicted* real total costs to PSNH's *actual* real total costs. We calculate a percentage difference and summarize how PSNH fares over the period. This is a commonly accepted methodology to conduct an econometric cost benchmarking analysis, with the difference between predicted and actual costs being a measure of cost efficiency.

Econometrics is the use of statistical methods for estimating economic relationships, in our case the relationship between a company's total costs and its output and operating characteristics. Econometric analysis involves a dependent variable that is the variable that is being "explained" in the model—in our case total costs—and a set of independent variables, the variables that are the "explanatory" variables. The dependent variable is a variable that we estimate a relationship for, whose value depends on a set of external variables. The independent variables and the functional form assumed help define the relationship and form the basis on which we model the dependent variable.

For our econometric analysis, the dependent variable is the total real cost of inputs—specifically, the same total *real* cost of inputs that we discussed in the previous section in the unit cost benchmarking analysis. We then regress total real costs on two output quantity metrics as well as a time trend and a variable controlling for the percent of the utility's total plant that is distribution plant.

To estimate the econometric models, we need to utilize an econometric estimator. We utilize two different econometric estimators. We first estimate the econometric model using an ordinary least squares ("OLS") estimator. An OLS model is a commonly used estimator in econometrics and is a standard estimator to utilize when first estimating econometric models and to compare the OLS results with other estimators.

We also utilize a fixed-effects ("FE") estimator to estimate the model. The FE estimator is a commonly used estimator when the dataset is a "panel" dataset. A panel dataset contains observations on the *same* units of analysis over time. Our cost benchmarking dataset is a panel data set, as we have observations on the same 87 electric utilities over a 23-year period. Accounting for the panel nature of the dataset is important because there may be certain *unobservable* cost drivers that are specific to companies that drive their distribution activities and costs. Failure to account for these features of the dataset and treating each observation as an independent observation can lead to an "omitted variable bias" problem.

An FE estimator is particularly attractive for use in an econometric cost benchmarking analysis for the electric industry as it helps solve the omitted variable bias. This benefit of the FE estimator is particularly important and relevant in cost benchmarking of the electric industry, as discussed in the academic literature.[49] A challenge in a cost benchmarking analysis of the electric industry is attempting to ensure that the results properly reflect the types of costs that management can control, influence and that can be affected through improved incentives, such as implementation of PBR. A utility should not be penalized (rewarded) for having higher (lower) costs than the industry due to factors outside its control, such as differences in some operating conditions. An additional problem is that due to the challenges in obtaining data, econometric cost models cannot be expected to control for all operating conditions that affect a utility's costs, so that some of the important factors that affect costs may be unobservable and not included as a dependent variable in the cost model. Failure to account for these concerns can erroneously bias the cost benchmarking analysis and lead to incorrect conclusions. Use of a FE estimator helps mitigate these concerns.

Table 5 below presents results of the two econometric cost benchmarking models. The first column presents the results when the model is estimated using OLS and the

[49] *See*, for example, Agustin J. Ros, Timothy J. Tardiff and Sai Shetty, "Performance based regulation in electricity and cost benchmarking: theoretical underpinnings and application." *Journal of Regulatory Economics* (2024): 1-33.

second column presents the results when the model is estimated using FE. The models are statistically significant as reflected in the F-test statistic.[50] The two variables in the model that are statistically significant are the number of customers and the time trend.

Table 5: Econometric Cost Benchmarking Models

Variable	OLS	Fixed Effects
Total Customers	0.9431***	0.5261***
	(0.1077)	(0.1398)
Total MWh	0.0594	-0.1076
	(0.1036)	(0.1628)
% of Distribution Plant	0.2849	-0.0602
	(0.1565)	(0.0551)
Time Trend	0.0029*	0.0064***
	(0.0014)	(0.0017)
Constant	5.3556***	13.8603***
	(0.6359)	(1.8545)
Observations	2001	2001
R-squared	0.9269	0.3728
F Statistic	242.54***	47.78***

Note: Standard errors in parentheses. *** p<0.001, ** p<0.01, * p<0.05

The next step in our econometric cost benchmarking analysis is to utilize the parameters from the econometric model estimated in Table 5 to predict the total real costs for each company. This is also known as an “in-sample” estimate of costs—for each company costs are predicted for the dependent variable using the value of the independent variables for each company. We then compare the *predicted* costs to the *actual* costs to see how close or distant actual costs are to predicted, the difference is the basis for conclusions on cost efficiencies.

50 The null hypothesis of the F-test is that none of the independent variables jointly have an effect on the dependent variable, in our case that none of the independent variables help explain a utility’s total real costs. We reject this hypothesis at high levels of statistical significance.

We predict total costs for PSNH using both the OLS and the FE models from Table 5, above. We then compare PSNH's predicted costs to its actual costs as per the following formula, to provide a measure of cost performance.

$$\%\, Difference\ in\ costs = ln\left(\frac{Actual\ Costs}{Predicted\ Costs}\right) \tag{11}$$

Table 6, below, presents the results of the econometric cost benchmarking analysis. A negative value in a year indicates PSNH had lower costs than those predicted by the model and a positive value indicates that PSNH had higher costs than those predicted by the model. Over the entire period, the FE model shows that PSNH's actual costs were practically equal to the model's predicted costs, being only 0.18% above. The FE results show that PSNH's actual costs were significantly below the model's predicted costs in the earlier periods, followed by actual costs being above predicted costs in the more recent periods, with two outliers during the height of the pandemic. The OLS model, which for the reasons discussed above we place less weight on, shows PSNH's actual costs were approximately 5.5% higher than the model's predicted costs.

In summary, our two cost benchmarking analyses reach similar conclusions—PSNH is an average cost performer. Our unit cost benchmarking analysis shows that PSNH's unit costs are very close to the electric industry's average unit costs, being approximately only 3% higher. For our econometric cost benchmarking analysis, using our preferred FE model PSNH's actual costs are practically equal to PSNH's predicted costs, only 0.18% higher. Even use of the OLS estimator resulted in PSNH's actual costs being approximately 5.5% higher than its predicted costs—supporting the conclusion that PSNH is an average cost performer.

Table 6: Cost Benchmarking Results for PSNH

Year	PSNH	
	% Difference (OLS)	% Difference (Fixed Effects)
2001	-4.23%	-12.07%
2002	-2.55%	-10.24%
2003	-2.52%	-9.11%
2004	-5.00%	-7.47%
2005	-6.81%	-8.66%
2006	-6.66%	-8.93%
2007	-6.00%	-8.29%
2008	0.63%	-2.85%
2009	4.37%	-1.42%
2010	4.96%	0.59%
2011	9.20%	2.37%
2012	9.36%	2.29%
2013	12.38%	5.28%
2014	9.43%	2.26%
2015	12.92%	5.34%
2016	14.22%	6.53%
2017	15.11%	7.53%
2018	5.97%	3.30%
2019	10.87%	7.19%
2020	15.88%	11.43%
2021	17.12%	12.37%
2022	12.07%	6.47%
2001 - 2022	***5.49%***	***0.18%***

VII. Conclusions

In this report we have discussed PBR, its incentive properties, the PBR formulas used in price and revenue cap plans, and the theory and practice of the stretch factor and the proper role of a cost benchmarking analysis. The focus of this report is on the X-Factor, discussing the economic principles that guide the derivation of the X-Factor and the importance of the inflation measure in determining the X-Factor formula.

PSNH is proposing a revenue-cap PBR formula with the inflation measure being GDP-PI. Under PSNH's proposal, the economically appropriate X-Factor is the differences in the TFP and input price growth between the electric-distribution *industry* and the overall economy.

We have developed an electric industry TFP and X-Factor model. We calculate that during the period 2000 to 2022, the X-Factor averaged **-1.42%**. Therefore, a revenue-cap PBR plan for an electric-distribution company that has just and reasonable going-in rates and has a PBR formula that results in annual allowed revenue changes in years two, three and four of **GDP-PI + 1.42%** results in rates that mimic the outcomes that one would observe under competition, while remaining "just and reasonable," consistent with applicable ratemaking principles.

We have conducted cost benchmarking analyses, finding that the PSNH's costs are close to the electric industry's average costs. Our findings, in combination with regulatory judgment and precedent, assist in the establishment of a stretch factor for PSNH's PBR plan. The Company is proposing a stretch factor of 15 basis points when inflation exceeds two percent. The Company's stretch factor, however, is *effectively* higher than the 15 basis points because although the X-Factor we calculate is -1.42%, the Company has set the X-Factor at zero with some of the difference being akin to a stretch factor. Moreover, in a revenue-cap PBR formula—with or without a revenue decoupling mechanism—the formula contains an additional component capturing the growth in customers expected during the PBR plan. Without a customer growth factor in the PBR plan, the Company may be unfairly penalized (rewarded) for customer growth (declines). These reasons—regulatory judgment and precedent; PSNH's cost performance per the cost benchmarking analysis; and the fact that the Company is setting the X-Factor to be zero rather than the -1.42% that we calculate in our X-Factor Study—support the Company's stretch factor proposal.

Appendix I: Metrics and Data Sources Used in the TFP and X-Factor Study

Category	Components	Source
Output Quantity Metrics	Total Customers	EIA Form 861
	Total Electric Volume (MWh)	EIA Form 861
Labor Input Costs	Distribution, Salaries and Wages	FERC Form 1: Page 354, Line 23, Column b
	Customer Accounts, Salaries and Wages	FERC Form 1: Page 354, Line 24, Column b
	Customer Service and Information, Salaries and Wages	FERC Form 1: Page 354, Line 25, Column b
	Sales, Salaries and Wages	FERC Form 1: Page 354, Line 26, Column b
Materials Rents & Services Input Costs	Distribution, O&M	FERC Form 1: Page 322, Line 156, Column b
	Customer Accounts, O&M	FERC Form 1: Page 322, Line 159-164, Column b
	Customer Service and Information, O&M	FERC Form 1: Page 323, Line 171, Column b
	Sales, O&M	FERC Form 1: Page 323, Line 178, Column b
Capital Input Costs	Distribution, Plant in Service	FERC Form 1: Page 207, Line 75, Column g
	Distribution Plant, Additions	FERC Form 1: Page 206, Line 75, Column c
	Distribution Plant, Retirements	FERC Form 1: Page 207, Line 75, Column d
	Net Distribution Plant	S&P Capital IQ
Adminstrative and General Input Costs	Total Administrative and General Expenses, O&M	FERC Form 1: Page 323, Line 197, Column b
	Total Electric O&M Expenses	FERC Form 1: Page 323, Line 198, Column b
	Administrative and General, Salaries and Wages	FERC Form 1: Page 354, Line 27, Column b
	Administrative and General, Pensions and Benefits	FERC Form 1: Page 323, Line 187, Column b
	Total Electric Operations and Maintenance, Salaries and Wages	FERC Form 1: Page 354, Line 28, Column b
General Plant Input Costs	General Plant, Plant in Service	FERC Form 1: Page 207, Line 99, Column g
	General Plant, Additions	FERC Form 1: Page 206, Line 99, Column c
	General Plant, Retirements	FERC Form 1: Page 207, Line 99, Column d
	Total Electric Plant In Service	FERC Form 1: Page 207, Line 104, Column g
	Intangible Plant, Plant in Service	FERC Form 1: Page 205, Line 5, Column g
	Net General Plant	S&P Capital IQ
Price Indices	Employment Cost Index	U.S. Bureau of Labor Statistics, Employment Cost Index, Wages and salaries for Private industry workers in Utilities, Index
	Price Indexes for Gross Domestic Product	U.S. Bureau of Economic Analysis, Price Indexes for Gross Domestic Product
	Electric Plant Construction Price Index	Whitman, Requardt and Associates, LLP
	Corporate Profits Tax Rate	U.S. Internal Revenue Service, Statistics of Income Historical Table 24
	Cost of Debt, Total Long Term Debt	FERC Form 1: Page 112, Line 24, Column c
	Cost of Debt, Interest on Long Term Debt	FERC Form 1: Page 117, Line 62, Column c
	Return on Equity	S&P Capital IQ, Pending Rate Cases
	30 Year Bond Yields	U.S. Department of the Treasury, Daily Treasury Par Yield Curve Rates
	Consumer Price Index	U.S. Bureau of Labor Statistics, Consumer Price Index
Economy-wide TFP Estimates	U.S. Economy Input Price Growth	U.S. Bureau of Economic Analysis, Price Indexes for Gross Domestic Product
	U.S. Total factor productivity for Private Business Sector	U.S. Department of Labor, Bureau of Labor Statistics, Total factor productivity for Private Business Sector

Appendix II: Electricity Distribution Companies Used in the TFP and X-Factor Study

Alabama Power Company	MDU Resources Group Inc.
ALLETE (Minnesota Power)	Metropolitan Edison Company
Appalachian Power Company	Mississippi Power Company
Arizona Public Service Company	Monongahela Power Company
Atlantic City Electric Company	Narragansett Electric Company
Avista Corporation	Nevada Power Company
Baltimore Gas and Electric Company	New York State Electric & Gas Corporation
Black Hills Power, Inc.	Niagara Mohawk Power Corporation
Central Maine Power Company	Northern Indiana Public Service Company
Cleco Power LLC	Northern States Power Company - MN
Cleveland Electric Illuminating Company	Northern States Power Company - WI
Commonwealth Edison Company	NSTAR Electric Company
Connecticut Light and Power Company	Ohio Edison Company
Consolidated Edison Company of New York, Inc.	Oklahoma Gas and Electric Company
Consumers Energy Company	Orange and Rockland Utilities, Inc.
Dayton Power and Light Company	Pacific Gas and Electric Company
Delmarva Power & Light Company	PacifiCorp
Dominion Energy South Carolina, Inc.	PECO Energy Co.
DTE Electric Company	Pennsylvania Electric Company
Duke Energy Carolinas, LLC	Portland General Electric Company
Duke Energy Florida, LLC	Potomac Edison Company
Duke Energy Indiana, LLC	Potomac Electric Power Company
Duke Energy Kentucky, Inc.	PPL Electric Utilities Corporation
Duke Energy Ohio, Inc.	Public Service Company of Colorado
Duke Energy Progress, LLC	Public Service Company of New Hampshire
Duquesne Light Company	Public Service Company of New Mexico
El Paso Electric Company	Public Service Company of Oklahoma
Empire District Electric Company	Public Service Electric and Gas Company
Entergy Arkansas, LLC	Puget Sound Energy, Inc.
Entergy Mississippi, LLC	Rochester Gas and Electric Corporation
Entergy New Orleans, LLC	San Diego Gas & Electric Company
Evergy Kansas South, Inc.	Sierra Pacific Power Company
Evergy Metro, Inc.	Southern California Edison Company
Florida Power & Light Company	Southern Indiana Gas and Electric Company
Georgia Power Company	Southwestern Electric Power Company
Green Mountain Power Corporation	Southwestern Public Service Company
Idaho Power Company	Tampa Electric Company
Indiana Michigan Power Company	Tucson Electric Power Company
Indianapolis Power & Light Company	Union Electric Company
Jersey Central Power & Light Company	United Illuminating Company
Kentucky Utilities Company	Virginia Electric and Power Company
Louisville Gas and Electric Company	West Penn Power Company
Massachusetts Electric Company	Wisconsin Electric Power Company
	Wisconsin Public Service Corporation

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Dr. Agustin J. Ros is an expert in regulatory economics with over 30 years of experience in energy and telecommunications and in financial and damages analysis. He is Adjunct Professor at the International Business School at Brandeis University where he teaches a course on global regulatory and antitrust economics and is an advisor to the Board of the Boston International Arbitration Council.

Dr. Ros has extensive expertise in total factor productivity ("TFP") analysis and performance-based ratemaking, cost of service, demand studies, competition analysis and disputes, damages, and econometric modelling. He has worked on dozens of TFP studies involving electricity, gas and telecommunications. He worked on the early TFP studies before the Federal Communications Commission and before state PUCs involving the incumbent local telephone companies. His work continued internationally, working on TFP studies in Peru, Canada and Mexico. Dr. Ros was an expert on behalf of the Alberta Public Utilities Commission where he conducted a TFP study for the electricity and natural gas distributors in Alberta and assisted in developing the TFP methodology and the model that was used and accepted by the Commission in that proceeding. He recently led a TFP, cost benchmarking and stretch factor study on behalf of Hydro-Québec TransÉnergie before the Régie de l'énergie. He has published academic articles on the topic of TFP and performance-based ratemaking and has a recently-published article on cost benchmarking in the electricity sector in the *Journal of Regulatory Economics*.

Dr. Ros has filed more than sixty expert reports and testimony before U.S. Federal District Courts, the Federal Communications Commission, the Federal Energy Regulatory Commission, the Canadian Competition Commission, the Canadian Radio and Telecommunications Commission, before U.S. and Canadian public utility commissions and the International Chamber of Commerce. Internationally he has filed expert reports in Australia, Bahamas, Barbados, Brazil, Colombia, El Salvador, Guatemala, Honduras, Indonesia, Italy, Mexico New Zealand, Peru, Singapore, Spain, and Trinidad and Tobago.

Dr. Ros has also worked as an economist at the Illinois Commerce Commission and the Federal Communications Commission. At the ICC he was Executive Assistant to the Chairman advising the Chairman on all economic and policy matters before the Commission and was selected to participate in the Federal-State partnership in Telecommunications at the FCC in 1996 where he worked on the economic rules implementing the local competition provisions of the Telecommunications Act of 1996. Dr. Ros is an expert in financial and damage analysis as well as in econometric and statistical analysis and has published his research in peer-reviewed academic and industry journals, such as the *Energy Journal*, *Energy Economics*, *Information Economics and Policy*, *Journal of Regulatory Economics*, *Review of Industrial Organization*, *Review of Network Economics*, *Telecommunications Policy*, and *Info*.

AREAS OF EXPERTISE

Energy and Telecommunications

Performance Based Regulation

TFP, X-factor and Cost Benchmarking

EDUCATION

Ph.D. Economics, University of Illinois - Urbana Champaign	1994
M.S. Economics, University of Illinois – Urbana Champaign	1991
B.A. Economics, Rutgers University – Newark, N.J.	1989

PROFESSIONAL EXPERIENCE

Ankura Consulting Group, Senior Managing Director	2023 – present
Brattle Group, Principal	2017 – 2023

NERA Economic Consulting, Senior Managing Director	1996 – 2017
OECD, Economist	2008 – 2010
Illinois Commerce Commission	1994 – 1996

TEACHING POSITIONS

Adjunct Professor, Brandeis University, International Business School	2016 – present
Guest Lecturer, University of Anahuac, Mexico City	2010
Adjunct Instructor, Northeastern University	2000

EXPERT REPORTS, TESTIMONIES AND AFFIDAVITS

1. Report on behalf of Liberty Utilities Gas New Brunswick before the New Brunswick Board of Public Utilities, Review of Liberty's Rate Design, Revenue Decoupling and Common Practices in Natural Gas, with Sai Shetty and Purvaansh Lohiya, March 3, 2023.

2. Rebuttal Report on behalf of Plaintiff before the United States District Court Southern District of Florida Fort Pierce Division, Case No. 21-14354-CIV-CANNON in the matter of Plaintiff, Town of Indian Shores *v.* Defendant, City of Vero Beach regarding antitrust assessment of territorial market allocation agreement, October 7, 2022.

3. Expert Report on behalf of Plaintiff before the United States District Court Southern District of Florida Fort Pierce Division, Case No. 21-14354-CIV-CANNON in the matter of Plaintiff, Town of Indian Shores *v.* Defendant, City of Vero Beach regarding antitrust assessment of territorial market allocation agreement, September 6, 2022.

4. Prepared Answering Testimony on behalf of Tri-State Generation and Transmission Association, Inc., before the Federal Energy Regulatory Commission in Dockets Nos. ER20-2441-002, ER20-2442-002, EL20-68-002, ER21-426-001, ER21-682-002, ER21-768-002 (Consolidated) on just and reasonable rates and undue discrimination, July 15, 2022.

5. Rebuttal Expert Report on behalf of Defendants before the United States District Court Southern District of Florida Ft. Lauderdale Division, in the matter of Plaintiffs Café Gelato & Panini LLC d/b/a Café Gelato Panini, on behalf of itself and all others similarly situated, *v.* Defendants Simon Property Group INC., Simon Property Group, L.P., M.S. Management Associates, and the Town Center at Town Center at Boca Raton Trust, June 3, 2022.

6. Expert Report on behalf of Defendants before the United States District Court Southern District of Florida Ft. Lauderdale Division, in the matter of Plaintiffs Café Gelato & Panini LLC d/b/a Café Gelato Panini, on behalf of itself and all others similarly situated, *v.* Defendants Simon Property Group INC., Simon Property Group, L.P., M.S. Management Associates, and the Town Center at Town Center at Boca Raton Trust, May 17, 2022.

7. Expert report before the Régie de l'énergie on behalf of Hydro-Québec TransÉnergie, Response to PEG's Commentary on HQT's MRI Evidence, with Sai Shetty, November 29, 2021.

8. Expert report before the Régie de l'énergie on behalf of Hydro-Québec TransÉnergie, Total Factor Productivity and the X-factor for Hydro-Québec TransÉnergie, with Walter Graf, Sai Shetty and Maria Castaner, February 19, 2021.

9. Expert report on behalf of North Carolina Municipal Power Agency Number 1, Piedmont Municipal Power Agency, and North Carolina Electric Membership Corporation on electricity cost allocation of nuclear fleet costs in arbitration proceeding against Duke Energy Carolinas, November 13, 2020.

10. Expert report before the Canadian Radio and Telecommunications Commission, on behalf of Bragg Communications Inc. (c.o.b. Eastlink), Cogeco Communications Inc., Rogers Communications Canada Inc., Shaw Cablesystems G.P., and Videotron Ltd., Assessment of an Expert Report by the Brattle Group Regarding Telecom Order CRTC 2019-288, with Renée M. Duplantis, Dimitri Dimitropoulos and Ian Cass, March 13, 2020.

11. Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-057, on behalf of the Staff of the New Hampshire Public Utility Commission on electricity marginal cost of service studies, December 20, 2019.

12. Rebuttal Testimony before the Virginia Corporation Commission, Case No. PUR-2019-00104, on behalf of the Virginia Electric Power Company on cost allocation of utility scale solar projects, December 19, 2019.

13. Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-064, on behalf of the Staff of the New Hampshire Public Utility Commission on electricity marginal cost of service studies, December 6, 2019.

14. Expert report on behalf of the Newfoundland and Labrador Board of Commissioners of Public Utilities: Review of Existing and Proposed Network Additions Policies for Newfoundland and Labrador Hydro, with Philip Hanser and Peal Donohoo-Vallet, November 19, 2019.

15. Expert report on behalf of Bragg Communications Inc. (c.o.b. Eastlink), Cogeco Communications Inc., Rogers Communications Canada Inc., Shaw Cablesystems G.P., and Videotron Ltd., Analysis of CRTC's Final Rates for Aggregated Whoelsale High-Speed Access Services: Impact on Broadband Network Investment and Innovation, with Renée M. Duplantis, Dimitri Dimitropoulos and Ian Cass, November 13, 2019.

16. Testimony before the Virginia Corporation Commission, Case No. PUR-2019-00104, on behalf of the Virginia Electric Power Company on cost allocation of utility scale solar projects, July 1, 2019.

17. Expert report on behalf of the Newfoundland and Labrador Board of Commissioners of Public Utilities: Embedded and Marginal Cost of Service Review, with Philip Hanser, T. Bruce Tschusida, Pearl Donohoo-Vallet, and Lynn Zang, May 3, 2019.

18. Expert report on behalf of Shaw Communications before the Canadian Legislative Review Panel of the Broadcasting and Telecommunications: Analysis of BDU Contributions, ISP Taxes and Regulations in the Canadian Broadcasting and Telecommunications Industries: Economic Efficiency, Investment and Innovation, with Coleman Bazelon and Renée Duplantis, January 11, 2019.

19. Expert opinion on behalf of CFE International LLC before the U.S. Citizenship and Immigration Services and Department of Homeland Security: An Overview of the Mexican Energy Markets and Reforms, October 25, 2018.

20. Expert report on behalf of Shaw Communications before the Canadian Competition Bureau: An Analysis of Broadband Services in Canada, Competition, Regulation and Investment with Coleman Bazelon and Renée Duplantis, August 30, 2018.

21. Affidavit on behalf of CFE International LLC before the Federal Energy Regulatory Commission: market-based rate authority application on vertical and horizontal market power issues in U.S. electricity markets, with Judy Chang, June 13, 2018.

22. Expert report on behalf of the Australian Competition and Consumer Commission (ACCC), before the ACCC: International experiences in retail electricity markets, with Toby Brown, Neil Lessem, Serena Hesmondhalgh, James D. Reitzes and Haruna Fujita, June 2018

23. Expert report on behalf of Transportadora de Gas Natural de la Huasteca, S. de R.I. de C.V. before the Mexican Energy Regulatory Commission: expert opinion on issues related to the appropriate allowed rate of return for the TGNH pipeline, with Paul Carpenter and Bente Villadsen, May 23, 2018.

24. Expert report on behalf of Infraestructura Marina del Golfo, before the Mexican Energy Regulatory Commission: expert opinion on issues related to the appropriate allowed rate of return for the IMG pipeline, with Paul Carpenter and Bente Villadsen, May 23, 2018.

25. Expert report on behalf of GCI Communications before the Federal Communications Commission: rate of return, cost of service and cross-subsidy analysis of GCI's Satellite-Based Services, with William Zarakas and Nicolas E. Powers, May, 2018.

26. Expert report on behalf of GCI Communications before the Federal Communications Commission, In the Matter of Connect America Fund and Universal Service Reform, WC Docket No. 10-90 and WT Docket No. 10-208A: analysis of the FCC's Rural Health Care Program Funding and Recipients, with William Zarakas, David Kwok, and M. Elaine Cunha, September 2017.

27. Expert report on behalf of Teléfonos de Mexico before the Mexican Telecommunications Authority: measurement of total factor productivity for Teléfonos de Mexico, July, 2014.

28. Expert report on behalf of Citibank, before the Honduran Competition Commission: expert report on the competitive effects of the FICHOSA – Citibank merger, April, 2014.

29. Expert report on behalf of America Móvil before the Mexican Competition Commission: correcting the OECD's erroneous assessment of competition in the Mexican telecommunications sector, May 2013. With Professor Jerry A. Hausman.

30. Expert report on behalf of Leyde and LACTHOSA before the Honduran Competition Commission: expert report on the competitive effects of a joint venture between Leyde and LACTHOSA in the Honduran dairy sector, April 2013.

31. Expert report on behalf of Lowe's Mexico before the Mexican Competition Commission: economic analysis on market definition, market power and monopolistic practices in the market for home improvement products sold through superstores, October 2012.

32. Expert report on behalf of Comcel before the Regulatory Commission of Communications in Colombia: expert report on economic analysis of Resolution CRC 3139 2011 regarding on-net and off-net pricing and termination rates, November 9, 2011.

33. Expert report on behalf of ESSOSA and Puma before the El Salvador Competition Commission: expert report on the competition implications of assets sales in El Salvador, (with Ramsey Shehadeh) October 5, 2011.

34. Expert report on behalf of ESSOSA and Puma before the Honduran Commission for the Defense and Promotion of Competition: expert report on the competition implications of assets sales in Honduras, (with Ramsey Shehadeh) July 19, 2011.

35. Testimony before the state of Illinois on behalf of Northern Illinois Gas Company, Docket No. 11-0046, surrebuttal testimony regarding market definition, market power and public interest considerations, filed April 22, 2011.

36. Testimony before the Alberta Public Utility Commission, Proceeding 566 Electricity Rate Regulation Initiative, update, reply and PBR review study, filed February 22, 2011.

37. Testimony before the Alberta Public Utility Commission, Proceeding 566 Electricity Rate Regulation Initiative, total factor productivity study, filed December 30, 2010.

38. Testimony before the state of Illinois on behalf of Northern Illinois Gas Company, Docket No. 09-0310, rebuttal testimony regarding market definition, market power and public interest considerations, filed August 6, 2010.

39. Expert report before the Commission for the Supervision of Business Competition of the Republic of Indonesia on behalf of Singapore Telecommunications Limited and Singapore Telecom Mobile, "Competitive Assessment of the Indonesian Mobile Sector," (with William E. Taylor, Nigel Attenborough and Christian Dippon), filed October 15, 2007, rebuttal report filed January 11, 2008.

40. Expert report before the Ministry of Economic Affairs and Development on behalf of Cable and Wireless Barbados, "An Economic Assessment of Mandating Indirect Access in Barbados," (with Michael Khyefets and Loren Adler), November 14, 2007.

41. Expert report before the Supervising Agency for Private Investment in Telecommunications in Peru (OSITPEL) on behalf of Telefonica de Peru, expert report on economic efficiency considerations with respect to termination rates and the impact of capacity-based charges, (with Jose Maria Rodriguez), filed October 17, 2007.

42. Expert report before the Canadian Radio and Telecommunications Commission (Telecom Public Notice CRTC 2006-14) on behalf of Bell Aliant Regional Communications, "Telecommunications Competition in the US: An Assessment of Wholesale Regulation Policy," (with William E. Taylor), filed March 15, 2007.

43. Expert report before the New York Public Service Commission (Case 06-C-0897) on behalf of Verizon New York, "Report on Competition for Retail Business Services," (with William E. Taylor and Harold Ware), filed report August 31, 2006. Supplemental Report filed October 2, 2006.

44. Expert report before the Telecommunications Authority of Trinidad and Tobago on behalf of Telecommunications Services of Trinidad and Tobago, response to Digicel's economic analysis of Interconnections costs and rates, filed May 12, 2006 (with Timothy Tardiff).

45. Expert report before the Telecommunications Authority of Trinidad and Tobago on behalf of Telecommunications Services of Trinidad and Tobago, expert report on interconnections costs in Trinidad and Tobago, filed May 4, 2006 (with Timothy Tardiff).

46. Expert report before the Telecommunications Authority of Trinidad and Tobago on behalf of Telecommunications Services of Trinidad and Tobago, expert report on Benchmark Mobile Termination Rates, Evaluation of the Econ Report, filed February 10, 2006 (with Timothy Tardiff).

47. Expert report before the Supervising Agency for Private Investment in Telecommunications in Peru (OSITPEL) on behalf of Telefonica de Peru, expert report on OSIPTEL's imputation methodology, filed February 7, 2006 (with Jose Maria Rodriguez and Eduardo Prieto Kessler).

48. Expert report before the Comisión Federal de Telecomunicaciones de México, on behalf of Telcel, S.A., expert report measuring the cost Telcel incurs when providing interconnection services to operators, filed 22 June 2005.

49. Expert report before the Supervising Agency for Private Investment in Telecommunications in Peru (OSIPTEL) on behalf of Telefonica de Peru, final report regarding the estimation of Telefonica de Peru's total factor productivity for application in the 2004-2007 price cap regime (with José María Rodríguez Ovejero and Juan Hernández García), 21 June 2004.

50. Expert report before the Bahamas Public Utilities Commission, on behalf of the Bahamas Telecommunications Company, "Public Consultation on the Universal Service Obligation in The Bahamas," Comments filed 24 March 2004; Reply Comments filed 10 June 2004.

51. Expert report before the Canadian Radio-television and Telecommunications Commission on behalf of Aliant Telecom Inc., Bell Canada, MTS Communications Inc., Saskatchewan Telecommunications and Télébec, société en commandite, Public Notice 2003-10, "A Review of Rules and Regulations Governing Bundled Telecommunications Services." filed 12 March 2004, updated report filed 26 March 2004.

52. Expert report before the Bahamas Public Utilities Commission, on behalf of the Bahamas Telecommunications Company, "Public Consultation on Price Control of Bahamas Telecommunications Company," 19 September 2003.

53. Expert report before the Comisión Federal de Telecomunicaciones de México, on behalf of the Commission, "Telmex's 2003-2006 Price Cap Tariff Proposal," expert report in arbitration regarding the renewal of the price cap plan for Telmex (with William Taylor, Georgina Martinez, and Aniruddha Banerjee), 13 December 2002.

54. Expert report before the Honorable Arbitration Tribunal of Fairness in Guatemala, Case No. CENAC-A-01-2002, final report in arbitration regarding call termination costs in fixed and wireless networks (with José María Rodríguez Ovejero, Laurent Bensancon, and Juan Hernández García), September 2002.

55. Expert report before the Federal Communications Commission on behalf of BellSouth Corporation Docket Nos. 01-338, 96-98, 98-47 Reply Declaration (with William Taylor, Aniruddha Banerjee, and Charles Zarkadas) regarding unbundling obligations of local exchange carriers. Filed 17 July 2002.

56. Expert report before the Federal Communications Commission on behalf of Verizon Communications, Docket Nos. 01-339, 01-337, 02-33, Statement of 43 Economists on the Proper Regulatory Treatment of Broadband Internet Access Service, 3 May 2002.

57. Expert report before the New Zealand Commerce Commission on behalf of Telecom New Zealand, "Review of CostQuests' Associates Benchmarking Survey" (with William Taylor, Greg Houston, Tom Hird, Jaime D'Almeida, and Carol Osborne), May 2002.

58. Testimony before the State of Illinois on behalf of Verizon North Inc. and Verizon South Inc., Docket No. 98-0195, surrebuttal testimony regarding investigation into certain payphone issues as directed in Docket 97-0225, 16 July 2001.

59. Expert report before the Supervising Agency for Private Investment in Telecommunications in Peru (OSIPTEL) on behalf of Telefonica de Peru, final report regarding the estimation of Telefonica de Peru's total factor productivity for application in the 2001-2003 price cap regime (with Timothy Tardiff, José María Rodríguez Ovejero, and Juan Hernández García), 22 June 2001.

60. Testimony before the State of Illinois on behalf of Verizon North Inc. and Verizon South Inc., Docket No. 98-0195, rebuttal testimony regarding investigation into certain payphone issues as directed in Docket 97-0225, 20 April 2001.

61. Expert report before the New Zealand Commerce Commission, on behalf of Telecom New Zealand, "Costs of Telecommunications Competition Policies," final report exploring the indirect economic costs of changing competition policy to a more regulatory approach (with Harold Ware, Timothy Tardiff, and Nigel Attenborough), May 2000.

62. Testimony before the State of Illinois on behalf of GTE North Incorporated and GTE South Incorporated, Docket No. 98-0195, direct testimony regarding investigation into certain payphone issues as directed in Docket No. 97-0225, 21 December 1999.

63. Expert report before the Federal Communications Commission on behalf of US West, An Economic and Policy Analysis of Efficient Inter-Carrier Compensation Mechanisms for ISP-Bound Traffic, 12 November 1999.

64. Expert report before the Pennsylvania Public Utility Commission on behalf of Bell Atlantic Pennsylvania, Promised Fulfilled: Bell Atlantic-Pennsylvania's Infrastructure Development (with William Taylor, Charles Zarkadas, and Jaime D'Almeida), 15 January 1999.

65. Testimony before the State of Illinois on behalf of Illinois Gas Transmission Company, Docket No 98-0510, rebuttal testimony regarding certification of Illinois Gas Transmission Company as a Common Carrier by Pipeline and approval of rates and accounting, and for cancellation of the Certificate of Illini Carrier, LP, 11 January 1999.

66. Expert report before the Spanish Regulatory Commission on behalf of Telefónica, final report "Assessment of the methodology used by Telefónica in the calculation of the prices included in the interconnection reference offer and comparison with BT's interconnection prices" (with Nigel Attenborough, David Robinson, Yogesh Sharma, and José María Rodríguez Ovejero), October 1998.

67. Expert report before the Italian Regulatory Commission on behalf of Telecom Italia, final report "Volume Discounts: A Report for Telecom Italia" (with Nigel Attenborough, Andrea Coscelli, and Andrea Lofaro), October 1998.

68. Expert report before the Federal Communications Commission on behalf of Bell Atlantic, Docket Nos. 96-262, 94-1, 91-213, 96-263, "An Analysis of the Effects of Exchange Access Reform on Demand Stimulation" (with Charles Zarkadas), 27 April 1997.

RECENT CONSULTING ENGAGEMENTS

Consulting work on behalf of a major electricity and natural gas provider: Due diligence review and analysis of a liquified natural gas contract.

Consulting work on behalf of the Colombian regulator of energy and gas (CREG): Recommendations for a Tariff and Capacity Model for Natural Gas Transportation in Colombia, November 30, 2021.

Consulting work on behalf of the Colombian regulator of energy and gas (CREG): Report entitled "Review of International Experience Regarding the Regulation and Remuneration of Natural Gas Transportation and Recommendations for Colombia," November 12,.

Consulting work on behalf of the Colombian regulator of energy and gas (CREG): Report entitled "Market Diagnostic of the Colombian Natural Gas Transportation Market," October 16, 2021.

Consulting work on behalf of CPS Energy and the Rate Advisory Committee involving electricity and gas cost of service, rate design, energy efficiency and energy burden analysis, ongoing.

Consulting work on behalf of a private-equity firm interested in purchasing solar distributed generation assets: Regulatory policy considerations, main determinants of demand and forecasts involving distributed solar energy, 2020.

Consulting work on behalf of Consumers Energy, class cost of service for residential NEM customers, January 2020.

Consulting work on behalf of a large Mid-western electricity provider in the U.S.: Analysis of the costs to serve secondary and primary NEM and standby customers, 2019.

Consulting work on behalf of a municipal electricity provider in the U.S.: Rate Design Principles and Rate Review for electricity and water services, 2019.

Consulting report on behalf of large South American oil and gas company: Evaluation of proposal in relation to the regulation of wholesale petroleum prices, (Evaluación de las propuestas en relación con la regulación de los precios de reconocimiento), November 13, 2019.

Consulting work on behalf of a major electricity distribution company in the U.S.: cost study and competitive pricing principles of advanced metering services, 2018-2019.

Consulting work on behalf of a Canadian electricity provider: benchmarking analysis of generation utilities in transmission and regulatory practices with respective to generation procurement practices, distributed energy resources and customer-specific pricing practices, 2018.

Consulting work on behalf of a U.S. generation and transmission electricity cooperative: embedded and marginal cost of service studies to support rate reform initiative, 2018.

Consulting work on behalf of a major electricity distribution provider in the U.S.: develop a locational distribution marginal cost-based cost of service study to support the value of distributed energy resource proceedings, 2017 - 2018.

Consulting report on behalf of major foreign electricity and gas distribution company: Rules and regulations applicable to the competitive U.S. retail electricity providers in the U.S. and Canada: A regulatory assessment, November 2017.

Consulting report on behalf of major foreign electricity and gas distribution company: Rules and regulations applicable to the competitive U.S. retail natural gas providers in the U.S. and Canada: A regulatory assessment, November 2017.

Consulting work on behalf of the Cities of Garland, Mesquite, Plano, and Richardson appealing the decision by North Texas Municipal Water District affecting wholesale water rates, Texas PUC Docket No. 46662 and SOAH Docket No. 473-17-4964.WS: economic analysis of whether wholesale water rate charged by the District adversely affects the public interest and rate design issues., 2017 – 2018.

Consulting work on behalf of a major electricity distribution company in the U.S.: cost study and competitive pricing principles of advanced metering services, 2015 - 2016.

Consulting report for the Mexican National Center for the Control of Natural Gas: Electricity demand forecast for the National Mexican Electricity System for the period 2017-2030. December 2016. With Veronica Irastorza and Elvira Creel.

Consulting report for the Mexican Secretariat of Communications and Transport: "Econometric demand study of fixed and mobile broadband and telephony services and Pay-TV services using discrete choice analysis." January 2016. With Kenneth Train and Douglas Umaña.

Consulting report for the Mexican Secretariat of Energy, CFE horizontal generation split analysis: recommended number of CFE gencos. September 2015. With Hamish Fraser and Willis Geffert.
Consulting report for the Mexican Secretariat of Energy, CFE horizontal generation split analysis: Recommended optimal portfolio mix for the CFE gencos. September 2015. With Hamish Fraser and Willis Geffert.

Consulting report for the Mexican Secretariat of Energy, CFE horizontal generation split analysis: Identification of relevant markets within the Mexican wholesale electricity markets. August 2015. With Hamish Fraser and Willis Geffert.

Consulting report for the Mexican Secretariat of Energy: Vesting contract criteria and methodology report. July 2015. With Hamish Fraser, Gene Meehan and Kurt Strunk.

RECENT PRESENTATIONS

Presentation before Rutgers University Center for Research in Regulated Industries Western Conference: "Residential Rooftop Solar Demand and the Impact of NEM Compensation and Electricity Prices," June 23, 2022.

Presentation before Rutgers University Center for Research in Regulated Industries Western Conference: "PBR: What, Why and What Have You Done for Me Lately?" June 22, 2022.

Presentation before Rutgers University Center for Research in Regulated Industries Eastern Conference: "Residential Rooftop Solar Demand and the Impact of NEM Compensation and Electricity Prices," June 2, 2022.

Webinar Presentation, Cross-Border Energy Update: Recent Government Policy Changes and the Future of Power Projects in Mexico, June 10, 2020.

Presentation before the National Association of Regulatory Utility Commissioners (NARUC): Cost of Service Allocation in a New Era, February 9, 2020.

Presentation before Rutgers University's Center for Research in Regulated Industries, Advanced Workshop: "Empirical Assessment of the Demand for Residential Solar Distributed Generation and the Impact of Electricity Rate Design Reform, January 17, 2020.

Presentation before the Harvard Electricity Policy Group: Rate Design and Low Income Consumers June 12, 2019.

Presentation before Rutgers University Center for Research in Regulated Industries Eastern Conference: "Does Electricity Competition Work for Residential Customers?" May 30, 2019.
Presentation before Rutgers University's Center for Research in Regulated Industries, Advanced Workshop: "Residential Electricity Competition at a Crossroads," February 15, 2019.

Presentation before the EEI Electric Rates Advanced Course, "Introduction to Embedded Cost of Service," with Phil Q Hanser, July 2018.

Presentation before the EEI Electric Rates Advanced Course, "Introduction to Marginal Cost of Service," with Phil Q Hanser, July 2018.

Presentation before the Public Collaborative for the Puerto Rico Electricity System, "Introduction to Utility Regulation," with Karl McDermott, July 19, 2018.

Presentations before the Public Collaborative for the Puerto Rico Electricity System, "Introduction to Electricity System Planning," with Karl McDermott, July 19, 2018.

Presentation before the Public Collaborative for the Puerto Rico Electricity System, "Ownership Structure, Contracting Process and Wholesale Markets," with Karl McDermott, July 19, 2018.

Presentation before Rutgers University Center for Research in Regulated Industries Eastern Conference: "Marginal cost of service: electricity distribution locational marginal costs, with Phillip Q Hanser and T. Bruce Tsuchida, June 8, 2018.

Presentation before the World Forum on Energy Regulation, Cancun Mexico: "Rate design helping facilitate change in electricity markets," March 2018.

Presentation before Rutgers University's Center for Research in Regulated Industries, Advanced Workshop: "Utility of the future and cost of service: challenges and opportunities," January 2018.

Presentation before Rutgers University's Center for Research in Regulated Industries, 36th Annual Eastern Conference: "The evolving electricity distribution network – technological, competitive and regulatory implications." May 2017.

Presentation before Rutgers University's Center for Research in Regulated Industries, Advanced Workshop: "Costing and pricing of electricity smart grid service offerings and competitive implications." January 2017.

Presentation before Rutgers University's Center for Research in Regulated Industries, 35th Annual Eastern Conference: "Determinants of total factor productivity in the U.S. electricity sector and the effects of performance-based regulation." May 2016.

Presentation before Rutgers University's Center for Research in Regulated Industries, Advanced Workshop: "merger theory and practice in the U.S. electricity sector." January 2016.

PUBLICATIONS

1. Performance Based Regulation in Electricity and Cost Benchmarking: Theoretical Underpinnings and Application," with Timothy J. Tardiff and Sai Shetty, *Journal of Regulatory Economics*, published online 18 March 2024.

2. "Natural Gas Restrictions in the US: Examining the State of Play, Policy Objectives, Legal Developments, and Antitrust Implications," with Kelly Lear Nordby and Adam Berns, *Infrastructure,* ABA Infrastructure and Regulated Industries Sections, Vol. 63, No 1, Fall 2023.

3. "Determinants of fixed and mobile broadband demand in Mexico using discrete choice exercises and logit and conditional logit models," *Information Economics and Policy*, 64 (2023).

4. "Residential Rooftop Solar Demand and the Impact of NEM Compensation and Electricity Prices," with Sai Shetty, *Energy Economics* 118 (2023).

5. "Does electricity competition work for residential consumers? Evidence from demand models for default and competitive electricity services." *The Journal of Regulatory Economics* 58:1-32 (2020).

6. "Economic framework for compensating distributed energy resources: Theory and practice." (with Romkaew Broehm and Philip Hanser), *The Electricity Journal* 31(8): 14-22 (2018).

7. "The future of the electric grid and its regulation: Some considerations," *The Electricity Journal* 31(2): 18-25 (2018).

8. "An Econometric Assessment of Electricity Demand in the United States using Utility-Specific Panel Data and the Impact of Retail Competition on Prices." *The Energy Journal* 38(4): 73-99 (2017).

9. "An Econometric Assessment of Telecommunications Prices and Consumer Surplus in Mexico using Panel Data." (with Jerry A. Hausman), *Journal of Regulatory Economics*, vol. 43:284-304 (2013).

10. "Corrección de la Evaluación Errónea de la OCDE Acerca de la Competencia en el Sector de las telecomunicaciones en México." (con Jerry Hausman), *El Trimestre Economico* (2013).

11. "The Impact of Asymmetric Mobile Regulation in Colombia." (with Douglas Umana), *Info*, vol. 15 No. 3:54-65 (2013).

12. "Correcting the OECD's Erroneous Assessment of Telecommunications Competition in Mexico." (with Jerry A. Hausman), *CPI Antitrust Chronicle* June 2012.

13. "North American Performance-Base Regulation for the 21st Century." (with Jeff D. Makholm and Stephen Collins), *Electricity Journal* vol. 25, Issue 4, May 2012.

14. "The Determinants of Pricing in the Mexican Domestic Airline Sector: The Impact of Competition and Airport Congestion." *Review of Industrial Organization* vol. 38:1 (2011), pp 43-60.

15. "Anticipating Merger Guidelines from Mexico's Commission on Competition." (with Elizabeth M. Bailey), *International Antitrust Bulletin* vol. 4, (2010).

16. "X-factor Updating and Total Factor Productivity Growth: The Case of Peruvian Telecommunications, 1996-2003." (with Jeffrey I. Bernstein, Juan Hernandez and Jose Maria Rodriguez), *Journal of Regulatory Economics*, vol. 30:3 (2006), pp 316-342.

17. "Crecimiento de la demanda por servicios de comunicación móviles. Mitos y realidades (International Mobile Demand Growth: Myths and Reality)" (with Aniruddha Banerjee), *AHCIET Móvil* (September 2005).

18. "Concepto de costes básicos para la modelización entelecomunicaciones (Basic Economic Cost Concepts for Telecommunications Cost Modeling), Perspectivas en Telecomunicaciones (Perspectives in Telecommunications) (July 2005).

19. "Drivers of Demand Growth for Mobile Telecommunications Services: Evidence from International Panel Data." (with Aniruddha Banerjee), in Global Economy and Digital Society, Elsevier (2004).

20. "Patterns in Global Fixed and Mobile Telecommunications Development: A Cluster Analysis." (with Aniruddha Banerjee), *Telecommunications Policy*, vol. 28 (2004), pp. 107-132.

21. "The Impact of the Regulatory Process and Price Cap Regulation in Latin American Telecommunications Markets." *Review of Network Economics*, vol. 2 (2003), pp. 270-286.

22. "Does Employee Ownership Motivate Workers? Worker Effort, Shirking and Horizontal Monitoring in ESOP." The Determinants of the Incidence and the Effects of Participatory Organizations, Advances in the Economic Analysis of Participatory and Labor Management, edited by Takao Kato and Jeffrey Pliskin, Elsevier Science, vol. 7 (2003).

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KOLESAR BUCHANAN & ASSOCIATES LIMITED

An Overview of Performance Based Regulation

And its Application

Mark Kolesar

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Ankura Consulting Group

Prepared for Public Service Company of New Hampshire

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I. Introduction

Kolesar Buchanan & Associates Ltd. (KB&A) has been retained by Public Service Company of New Hampshire d/b/a Eversource Energy (PSNH) to provide an overview of Indexed Performance-Based Regulation including a survey of its application in various jurisdictions. The study team consists of Mr. Mark Kolesar of KB&A and Dr. Agustin J. Ros of Ankura Consulting Group (Ankura). The study team's report follows. The footnotes are an integral part of this report and should be read in full.

II. Qualifications of the Study Team

Mr. Mark Kolesar is Managing Principal at Kolesar Buchanan & Associates Ltd. He has more than 30 years of experience in the regulated utilities sector in the areas of regulation and public policy, external relations, marketing, strategy and business development, and mergers and acquisitions, including over 20 years of corporate experience in the telecom sector where Mr. Kolesar was Vice President, Economic Affairs at TELUS. Mr. Kolesar was a member of the Alberta Utilities Commission (AUC) for twelve years, including six years as Vice Chair and two years as Chair of the Commission. He is now a researcher, author and consultant in utility regulation and policy development, and a frequent participant in webinars and conferences in Canada and the U.S. His principal areas of expertise are regulatory policy, the theory and implementation of PBR, rate design, facilities approvals, rate of return, and the impact of distributed energy resources on regulatory frameworks.

Specific to this study, Mr. Kolesar was instrumental in the adoption of PBR in Alberta, while a member of the AUC. During his AUC tenure he adjudicated numerous PBR applications for two gas distribution utilities, four electric distribution utilities and one electric transmission utility. He has subsequently advised several utilities and regulators in matters related to PBR.

Dr. Agustin J. Ros is Senior Managing Director at Ankura and Adjunct Professor at Brandeis University, International School of Business. He has more than 30 years of experience in regulatory economics in electricity, natural gas, and telecommunications, with a focus on performance-based ratemaking. As an adjunct professor at Brandeis University Dr. Ros teaches a course on global regulatory economics and forms of regulating public utilities, including alternative forms of regulation such as PBR.

Specific to this study, Dr. Ros has been employed as an economist at the Illinois Commerce Commission (ICC), and the Federal Communications Commission (FCC) where he worked on numerous PBR assignments including one of the first PBR plans adopted in the country for Illinois Bell Telephone. His work in PBR continued at NERA where he worked for over a decade on dozens of cases throughout the U.S. and internationally involving all aspects of PBR, including establishing PBR goals, index-revenue formulas including calculations of the "X-factor" in I-X price formulas, establishing earning sharing mechanisms ("ESM") and performance incentive mechanisms ("PIMs"). He has published academic, peer-reviewed articles on PBR's impact on rates, estimating total factor productivity ("TFP"), setting of the X-factor, and cost-benchmarking.

III. Purpose of the Study

PSNH is proposing to file its first Performance-Based Rate Making (PBR) proposal with the New Hampshire Public Utilities Commission (NHPUC) in 2024. In support of that application, this study is intended to provide a comprehensive overview of PBR and its application in various representative jurisdictions nationally and internationally, including an explanation of the common elements that may make up a PBR plan.

IV. Scope and Layout of the Study Report

This study provides an overview of Indexed Performance Based Rate Setting Plans as applied to electric utilities across North America and elsewhere, including a discussion of the economic principles and technical application of the elements commonly included in PBR plans.

The study report:

- defines Performance-based Regulation (PBR) and provides an overview of Cost-of-Service Regulation (COSR) and PBR within the broader context of incentive regulation.
- discusses how PBR works and sets out the objectives of the design of a PBR plan.
- provides an overview of the generic formulas for capped indexed PBR plans and discusses their application.
- explains each element of a capped indexed PBR plan, with a survey of each element's application in recent PBR plans.
- Provides empirical research on the effect of PBR plans on utility performance

V. What is Performance-Based Regulation?

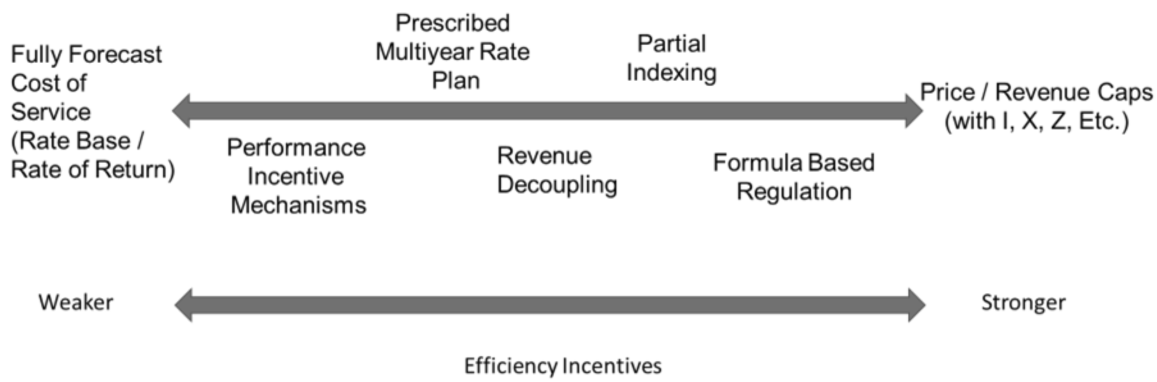
Economic regulation of utilities is an exercise in applied economics. The underlying objective of regulatory regimes is, or should be, to incentivize behavior among both the utility and its customers to achieve certain public policy outcomes, including preventing monopoly profits and the establishment of just and reasonable rates. The regulation of utility rates creates incentives that stakeholders respond to, whether intentional or not.[1] Sound regulation is intentional regulation that considers the incentives it creates.

It is instructive to consider performance-based regulation within the broader context of incentive regulation. Incentive regulation generally refers to a broad range of tools that provide incentives to utilities, including differing levels of cost efficiency incentives. Regulators may draw upon different tools depending on the goals of the regulatory regime. These tools include various performance incentive mechanisms, multi-year rate plans, revenue decoupling mechanisms, and index-based price or revenue

[1] Stakeholders in this context refers to any person or entity affected by a regulatory regime or with an interest in the implications of the regime, including the utility and its shareholders, employees, customers, legislators, suppliers, competitors, and market entrants, among others.

caps, among others. Figure 1 presents an illustration of how these tools form a continuum between Cost-of-Service Regulation (COSR) and index-based PBR.

Figure 1 Incentive Regulation[2]



Certain elements in the incentive regulation "menu" may be adopted to achieve specific public policy objectives within a COSR or PBR regime.[3] For example, the Commonwealth of Massachusetts Department of Public Utilities[4] adopted revenue decoupling to encourage certain public policy outcomes:

> This is a necessary evolution of Department ratemaking practices – it will help us address some of the profound impacts of increases in the costs of natural gas and electricity on the Commonwealth's residents and businesses. It will also provide distribution companies with better financial incentives to pursue a cleaner, more efficient energy future consistent with the recently enacted legislation, Chapter 169 of the Acts of 2008, An Act Relative To Green Communities ("Green Communities Act"). Today's Order paves the way for the aggressive expansion of demand resources (i.e., energy efficiency, demand response, combined heat and power, and renewable generation) in Massachusetts in a manner that fully maintains and enhances fundamental and long-standing Department precedent on ratemaking principles and consumer protections for all consumers of electricity and natural gas in the Commonwealth.

[2] This figure is an extension of that proposed by Dr. Dennis Weisman in "A Report on the Theory and Practice of Performance-Based Regulation." SSRN, 2021, papers.ssrn.com/sol3/papers.cfm?abstract_id=3765691.

[3] Not all elements in the continuum are directly related to efficiency incentives. Revenue decoupling facilitates the utility adoption of public policy objectives that may reduce revenue without reducing costs and is often paired with efficiency incentives.

[4] D.P.U. 07-50-A, July 16, 2008, page 1

When the objective of the regulator is to provide the utility with efficiency incentives, then it is necessary to consider the effect of every element or combination of elements in a proposed regulatory regime on the resulting efficiency incentives. [5]

VI. Incentives in COSR and PBR

At a high level, different incentives are created at the opposite ends of the continuum of alternatives available to a regulator interested in incentivising utility efficiency. The regulated utility with an incentive to maximize profits can be expected to respond differently at either end of the continuum. Dr. Dennis Weisman notes that:

> The textbook model of COSR with no regulatory lag contemplates instantaneous rate reductions that serve to normalize excess returns. This regulatory regime lies at the far left on this continuum indicating extremely weak (low-powered) incentives. In contrast, long-term PBR (price/revenue caps) with no earnings sharing or rebasing lies at the far right on this continuum indicating extremely strong (high-powered) incentives.[6]

A. COSR

Moving beyond the textbook model and considering COSR models more generally, COSR plans are commonly of limited duration and usually do not have a fixed stay-out period. Where a COSR plan does not include a defined stay-out period, the utility will come in with a rate application when experiencing significant earnings attrition or the regulator may call the utility in when it has a belief that the utility is significantly over-earning, which brings the COSR plan to a close. Rates may be adjusted periodically in a COSR plan to extend the stay-out period through rate adjustment mechanisms such as fuel adjustment clauses, but ordinarily not based on an indexed formula. As discussed further below, the longer the stay out period, the greater are both the incentives and the opportunities for the utility to seek out efficiencies. A shorter stay-out period increases regulatory burden for both the regulator and the utility because the utility will file rate applications more frequently.

There are several forms of COSR along the continuum, including multi-year rate plans and formula-based rate plans. Multi-Year Rate Plans span several years, however, unlike PBR they do not rely on an indexed formula to determine future rate increases. Annual rate changes may be established at the commencement of the plan, which is typically two or three years in length. When there is no rate change during the multi-year plan, then nominal rates are effectively capped which implies that inflation-adjusted rates decline.[7] Formula-based rate plans allow for annual rate adjustments between full rate cases, often based on the difference between a utility’s achieved return on equity and the return approved at the commencement of the plan. Annual rate adjustments generally follow a review of one

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[5] See Weisman, Dennis. “A Report on the Theory and Practice of Performance-Based Regulation.” SSRN, 2021, papers.ssrn.com/sol3/papers.cfm?abstract_id=3765691., Page 1.

[6] Ibid.

[7] Indeed, when this is the case, a multi-year rate plan effectively has an “X-factor” equal to the rate of inflation. We discuss the X-factor further below.

or more elements of the utility's revenue requirement. The Step Adjustment Methodology in New Hampshire is a form this type of COSR.

Regardless of the stay-out period, COSR regimes establish a projected revenue requirement deemed necessary to satisfy the service obligations of the utility at the level of quality established by the regulator for a future period and then approve rates intended to recover that revenue requirement. The projected revenue requirement may be established based on a future test year forecast, usually at most a one-year forecast, or an historical test year with necessary adjustments to determine the forward-looking revenue requirement. In New Hampshire and Massachusetts, the precedent for setting base distribution rates through a base rate case proceeding has been to rely on an historical test year adjusted for known and measurable changes.

There are some fundamental challenges faced by the utility, its regulator and interested parties in establishing a projected revenue requirement.[8] Perhaps the most significant challenge arises from informational asymmetry. The utility has access to more information and understands its business better than the regulator or interested parties, which creates challenges in assessing the reasonableness of the utility's proposed revenue requirement. Commissions are generally quite capable of fully understanding and assessing the reasonableness of rates application, having developed an institutional knowledge base over time. However, the challenge for the utility, the regulator and other parties resides in the sheer volume and complexity of the information on the record of a revenue requirement proceeding.

The process for setting base distribution rates generally involves a line-by-line analysis of the utility's costs, including those related to administrative expenses; operations and maintenance expenses; opening rate base and the related deprecation, taxes and return; projected capital additions for both capital maintenance and incremental capital investments necessary to replace aging infrastructure and to satisfy expected load growth, and the concomitant depreciation, taxes and return; the utility's capitalization policies; any cost allocations and the related allocation methodologies; the calculation of necessary working capital; the embedded cost of debt and additions to debt; the allowed return on equity investment, and the allowed debt to equity ratio. In addition, the analysis usually considers the requirement for and effects of various reserve accounts, deferral accounts and flow-through cost accounts.

None of this is to say that COSR should not be adopted. There may be very good reasons to implement a COSR regime. COSR may exhibit more high-powered efficiency incentives than PBR, in certain circumstances, if the efficiency incentive power of the regulatory lag can be formalized in some manner.[9] COSR may be a good alternative when certain conditions are present in the utility's market, precisely

[8] These same challenges may occur under COSR and under PBR when establishing the going-in base rates at the commencement of a PBR plan, as discussed further below. However, an advantage of a PBR plan is that this exercise is only undertaken at the beginning of the regime, and perhaps again at the beginning of a new regime, when the rates and utility cost are re-linked (rebased).

[9] See, Weisman, Dennis. "TRADEOFFS IN THE POWER OF REGULATORY REGIMES" https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4441445

because it does not break the link between costs and revenues. Given the lumpiness of capital additions in most utilities, when a utility is forecasting significant load growth, a PBR plan may struggle to adequately align the cost of capital additions required to serve increased load with the projected revenue provided by the PBR formula and the increase in billing determinants. The potential misalignment of revenues and costs may be more severe when the utility's billing determinants are stable, but it has aging infrastructure that requires replacement, resulting in significant capital additions to serve existing customers. An additional challenge may arise when a utility is required to invest in capital additions to facilitate certain new public policy objectives, the costs of which are not generally present in the historical data. For example, when electrification objectives may not result in timely increases in expected load, earnings attrition may result. Although a PBR regime may include factors to account for capital additions, these may be less effective than COSR in adequately recognizing the effect of capital requirements on utility costs.

Once the projected revenue requirement is established by the regulator, base rates are approved to recover the revenue requirement in each of the years that are the subject of the COSR regulatory regime, and the utility is set on a "revenue trajectory" for the duration of that regime. Barring any sufficiently significant events that might compel the regulator to bring the utility in for a subsequent review, or that might compel the utility to apply for a subsequent review, the base rates are not altered.

Because the annual revenue requirement that underlies the approved base rates in each of the years in the utility's current regulatory regime was based on a projection, it is certain that the actual utility costs in any year will be different than projected. The utility will face various deviations from both the projected revenues (due to fluctuating billing determinants) and costs in each year with which it must contend, as the various elements that made up the projected revenue requirement may vary either positively or negatively over time. In these circumstances, the utility will seek to adjust its behavior as necessary to recover its costs and continue to earn its regulated return. Hence, the utility will be compelled to seek efficiency improvements to overcome certain unanticipated revenue or cost "shocks" over time.

In addition, as discussed further below, a profit maximizing regulated utility even under COSR will be compelled to stay out (not come in for a rate case) and seek productivity[10] improvements beyond those necessary to simply recover from reductions in projected revenues or increases in costs sufficient to earn its allowed return. The incentive to achieve increased profits through efficiency gains is an objective of the economic regulation of utilities because customers ultimately benefit from any sustainable long run

[10] Productivity and efficiency are used interchangeably throughout this testimony. Productivity is the ratio of outputs produced to inputs involved in the process of production. The X factor in PBR is generally based on a productivity study. Efficiency, on the other hand, is the ratio of the actual output to standard output, in a unit of time. If efficiency improves (i.e., output increases) then fewer resources (labour, capital, etc.) are consumed per unit of output and productivity increases.

efficiency gains the utility achieves when they are reflected in base rates in a subsequent regulatory period.[11]

B. PBR

Pure PBR, as the term was coined by Dr. Weisman,[12] caps rates or revenues over a stay-out period that exceeds the period typically adopted for COSR regimes. Pure PBR excludes earnings sharing and rebasing at the end of the plan and prior to the beginning of a new plan, but includes other elements generally found in a PBR regime (e.g., Y, Z, K factors) which will be explained further in other sections of this study. As discussed elsewhere in this study, there are few examples of pure PBR, as defined here. Most PBR plans in the electricity sector include an earnings sharing mechanism and prescribe rebasing at the end of the stay-out period.

It is noteworthy that despite potential assumptions to the contrary, the process of approving and implementing a PBR regime is often no less time consuming, nor does it often require significantly less of an evidentiary record than that required under COSR to establish a revenue requirement and set rates. Both PBR and COSR require a significant amount of judgment on the part of the regulator. However, once the stay-out period begins there is usually significantly less regulatory burden than under a COSR regime because the stay-out period is longer.

The fundamental advantage of a PBR regime is that it adjusts the utility's cost of service and resulting rates annually based on an index, thereby allowing for a longer stay-out period and, accordingly, a greater incentive for the utility to seek out efficiencies. There is essentially a notional revenue requirement underlying the indexed revenue for each year of the PBR plan that assumes that the utility sector's costs will change as predicted by the inflation (I) factor and the level of productivity dictated by the X factor in the PBR formula. The industry's costs and the utility's notional revenue requirement become the benchmark for the utility and provide it with the incentives to surpass the benchmark and earn additional profits.

The level of productivity dictated by the X factor in the PBR formula is based on the average productivity growth achievable in the relevant utility sector. The expected productivity in the X factor of the PBR formula obliges the utility to seek out productivity improvements sufficient to earn its allowed return, while the longer stay-out period over which the regulatory regime is in place encourages a profit maximizing utility to seek additional productivity improvements that might only unfold over the longer term so as to exceed its allowed return.

[11] Under COSR, the regulator may be legislatively prohibited from allowing earnings to exceed the allowed return, as it would then imply rates are not just and reasonable. However, to the extent that earnings beyond the allowed return are a by-product of regulatory lag, the "over-earning" is tolerated, and any productivity improvements are accounted for in a subsequent regulatory period to the benefit of customers.

[12] See, Weisman, Dennis. "A Report on the Theory and Practice of Performance-Based Regulation." SSRN, 2021, papers.ssrn.com/sol3/papers.cfm?abstract_id=3765691., Page 1

As with COSR, once the PBR formula is established and the other elements of the PBR plan are approved by the regulator and set into motion, the utility is set on a "revenue trajectory" for the duration of the PBR regime—a revenue trajectory governed by the PBR formula. And, as with COSR, the utility will face various fluctuations, both positive and negative, in revenues and costs each year with which it must contend under the constraints of the cap. Some of these variances will reduce revenues or increase costs. Again, the utility will adjust its behavior and seek productivity improvements to overcome certain unanticipated revenue or cost "shocks" over time to recover its costs and continue to earn its regulated return. And, as with COSR, a regulated profit maximizing utility under PBR will be compelled to seek productivity improvements beyond those necessary to simply recover from reductions in projected revenues or increases in costs sufficient to earn its allowed return. The regulated profit maximizing utility will be incentivized to achieve increased profits through efficiency gains beyond those demanded by the PBR formula. Customers will benefit from any sustainable long run efficiency gains the utility achieves when they are reflected in base rates in a subsequent regulatory period, or more immediately if earnings sharing or a consumer dividend are included in the PBR plan.

It is worth noting that price cap and revenue cap PBR regimes do not depart from the principles underlying COSR that have been the foundation of utility regulation since Bonbright established the principles of public utility regulation in 1961.[13] The utility is afforded the same opportunity to recover its prudently incurred costs and earn a fair return. Rates under both COSR and PBR are just and reasonable and set to recover a prudent revenue requirement under both COSR and PBR. The fundamental difference in approach under PBR is the longer stay-out period and rates that are adjusted annually based on a formula rather than a projection. These are the elements from which the superior efficiency incentives of PBR are derived. Eventually, the rates and revenue requirement of the utility are re-based to ensure the benefits of PBR are fully shared with customers and to safeguard the on-going financial integrity of the utility. However, the time between rate setting proceedings can be significantly longer under PBR than COSR, thereby reducing regulatory burden.

VII. The Profit Motive is the Driver in Incentive Regulation

When the regulator's objective is to incentivize a utility to find and implement efficiency gains, the regulatory regime can be designed to optimize the profit maximizing incentive of the utility. Every element of the regime should be considered relative to the positive aspect of the incentive to maximize profitability while guarding against the negative aspects of the profit maximizing incentive—i.e., the potential to earn monopoly profits—all within the context of other non-efficiency-related objectives of the regulator.

As discussed above, under both PBR and COSR, a regulated profit maximizing utility will be compelled to seek productivity improvements beyond those necessary to simply recover from reductions in projected revenues or increases in costs sufficient to earn its allowed return. The regulated profit maximizing utility will seek a return beyond the allowed return approved by the regulator. To be clear, the "allowed return"

[13] Bonbright, B, 1961. Principles of Public Utility Rates

on investment is somewhat of a misnomer. It is the regulated return approved as part of the revenue requirement, pursuant to the fair return standard, and upon which base rates were set, but the utility is not prohibited from earning a return more than the allowed return. Indeed, utilities often respond to this incentive and seek productivity improvements under both PBR and COSR, thereby emulating to some extent the results expected in a competitive market, and in so doing retain at least some of the return above the allowed return. This utility behavior is accepted under normal circumstances pursuant to the regulatory bargain on the assumption that, at the end of the current regulatory regime, customers will benefit because the productivity improvements achieved in the current regime will be accounted for in the subsequent regime and passed on to consumers in future rates.[14]

PBR regimes are generally adopted with the specific objective of incentivizing efficiency gains because, if appropriately designed, they more strongly tap into the profit maximizing incentive of the utility. Under PBR, a regulated profit maximizing utility will be more strongly compelled to seek productivity improvements beyond those necessary to simply adjust to deviations in projected revenues and costs to earn its allowed return because the utility is able to retain at least some of the return above the allowed return over a longer stay-out period,[15] and because the cap on rates or revenues assumes a minimum level of productivity that the utility is required to achieve to earn its allowed return. However, in most circumstances, the sharing with consumers of the productivity improvements anticipated in a PBR plan is reflected in a consumer dividend (stretch factor) that compels the utility to share the "first cut" of the productivity gains. As a result, consumers benefit annually because utility revenue increases are constrained by the cap and again at the end of the PBR plan when the productivity gains achieved in the current regime are accounted for in a subsequent regime and passed on to consumers in future rates.

Of course, the efficiency objective must be balanced with other regulatory objectives when designing a PBR plan. This is why the design of PBR plans is not static and evolves over time. Regulators must respond to consumer and societal expectations, the evolution of utility markets, changing policy objectives and legislative requirements, and the outcomes of any prior PBR regimes. There are numerous tools at the disposal of a PBR plan designer that are discussed in detail in this study. These include the choice of inflation and productivity factors, flow-through adjustments, exogenous adjustments, capital funding mechanisms, earnings carry-over mechanisms, earnings sharing mechanisms, re-openers, off-ramps, the choice of a price cap or revenue cap, term length, stay-out period, quality monitoring mechanisms, performance incentive mechanisms, and revenue decoupling, among others. The choice of elements making up a PBR plan, all of which are explained in detail in the remainder of this report, must work in harmony to achieve the objectives of the plan while balancing regulatory, legislative, public policy and utility shareholder obligations. A well-designed PBR plan provides a reasonable balance

[14] As noted above, under COSR, the regulator may be legislatively prohibited from allowing earnings to exceed the allowed return, as it would then imply rates are not just and reasonable. However, to the extent that earnings beyond the allowed return are a by-product of regulatory lag, the "over-earning" is tolerated, and any productivity improvements are accounted for in a subsequent regulatory period to the benefit of customers.

[15] Indeed, the multiplier effect of the time value of money increases any incremental earnings exponentially the longer the stay-out period.

among the many objectives of the regulator and the obligations of the utility under the regulatory bargain.

Washington State, North Carolina, New York, Rhode Island, Illinois, Oregon, Nevada, Colorado, New Mexico, Ohio, Minnesota, Michigan, Pennsylvania, Maryland, Virginia and the District of Columbia are at various stages of stakeholder engagement to consider the adoption of PBR.

VIII. How does PBR Work?

The central idea of PBR is to rely on incentives to increase efficiency while reducing regulatory costs to produce just and reasonable rates. PBR can help to improve three types of efficiencies:

Productive efficiency: Taking customer demand as given, the utility satisfies that demand at the least cost possible and operates as close as possible to the frontier of the "production possibility set", which characterizes a firm operating at the most efficient level possible.

Allocative efficiency: Considering that customer demand for outputs and services can change based on their price, the utility provides the highest value range of outputs and services, given the least-cost mix of current inputs and future cost structure and technology.

Dynamic efficiency: The utility finds the optimal rate of innovation and investment to improve production processes, satisfy evolving consumer demand and reduce long-run average cost. [16]

Depending on the type of PBR plan, the main reason why PBR increases efficiency is it breaks the link between a company's actual costs and the prices it can charge customers. In general, productive efficiencies tend to be lower under cost-of-service regulation due to weaker incentives to reduce costs and increase efficiency. Several elements of PBR promote increased incentives to lower costs and improve performance. COSR is a "cost-plus" form of regulation whereby a firm's prices are linked to its underlying costs. An increase in prudently allowed costs results in higher prices. This results in lower incentives to minimize costs.[17] PBR reduces the link between realized costs and allowed rates. If a utility can find ways to meet demand while reducing costs, thereby increasing efficiency, it will keep some or all the cost savings as additional profit. Thus, firms operating under a PBR plan have the incentive to do so. In contrast, a utility under COSR is required to lower revenues if it lowered its costs. If the efficiency improvement under COSR relates to capital, the firm's profits may go down because the firm may have less capital (rate base) on which to earn a rate-of-return. As a result, under PBR customers are likely to benefit from lower rates *than would otherwise have been the case*, as well as increased rate stability and predictability over what would be expected under COSR.

[16] To the extent that it provides more flexibility to introduce new services and/or more attractive rate plans, PBR can also increase dynamic efficiencies.
[17] Cost-of-service regulation can provide incentives for reducing costs and increasing productive efficiency when rate case proceedings are infrequent—*i.e.*, through regulatory lag. A firm has an incentive to reduce costs between rate cases because it retains the benefits until the next rate cases. The longer the time between rate cases, the greater the incentive effects.

The potential for superior efficiency incentives and regulatory cost savings depends in part on the duration of a PBR plan. As mentioned earlier, in general, the longer the duration of the PBR plan, the greater the magnitude of the incentive effect because the utility has a longer period to seek out efficiency gains, some of which may not be fully realized over a shorter period, and the utility can keep any greater returns generated for a longer period. Typically, PBR plans can last anywhere from as little as two years to as long as ten years. Because PBR plans facilitate a longer stay out period, PBR can help to reduce the high regulatory and administrative costs and burdens of annual or periodic rate cases for both the regulator and the utility.

In addition to a PBR plan's duration, a key determinant of the strength of the incentives of the plan is whether the plan incorporates an earnings sharing mechanism. A PBR plan without earnings sharing provides greater incentive effects than plans with earnings sharing, which is effectively a tax on the incremental profits subject to sharing. However, as explained later in this report, earnings sharing mechanisms can serve as a vehicle to share benefits more readily with customers and, depending on their construction, an earnings sharing mechanism can also more equitably share risk.

IX. Objectives in the Design of a PBR Plan

Any regulated utility rate setting regime should seek to achieve the following objectives.

- Produce just and reasonable rates.
- Emulate the incentives of a competitive market to the greatest extent possible.
- Provide a reasonable opportunity for the utility to recover its prudently incurred costs and earn a fair return.
- Ensure the utility does not unduly benefit from nor be unduly penalized for events outside of its control.
- Be understandable by stakeholders.
- Avoid regulatory burden and ideally streamline regulation.
- Make parties better off relative to other regulatory alternatives, so that all stakeholders, including the utility and its customers, share in the benefits of the regime.
- Consider the unique circumstances of the utility.

The choice of a regulatory regime, the elements that make it up, and the weight ascribed to each objective by the regulator will determine the extent to which these objectives can be achieved. A PBR plan should seek to achieve these objectives by aligning each objective with the efficiency incentives of the plan to the extent possible. Clearly there will be trade-offs among the objectives. However, as mentioned above, the choice of elements making up a PBR plan can work in harmony to achieve the objectives of a sound regulatory regime if they provide a reasonable balance among the many objectives of the regulator and the obligations of the utility under the regulatory bargain, while more strongly focusing the utility on the achievement of efficiency gains. Each of these objectives is discussed in more detail below.

A. Produce just and reasonable rates

The cornerstone of public utility regulation is to ensure that the rates that consumers pay for utility service are just and reasonable and do not reflect rates one would observe for an unregulated monopolist. COSR leads to just and reasonable rates as a result of directly *regulating the profits* the utility can earn through the setting of rates that are tied directly to the utility's costs, which include a fair return on capital. PBR, by contrast, results in just and reasonable rates by directly *regulating the rates* the utility can charge through the setting of rates one would observe in competitive markets through the I-X formula, irrespective of the actual profits the utility earns.

B. Emulate the incentives of a competitive market

Although COSR may provide some cost minimizing incentives through the regulatory lag because the profit maximizing utility will try to earn a return beyond the allowed return by seeking efficiencies, a well-designed PBR plan can provide stronger incentives and thereby better emulate a competitive market. This is because PBR better incentivises the utility to invest in product and process innovation to increase efficiencies rather than focus on the optimal alignment of prices with underlying costs to align its base rates with its approved revenue requirement annually. A corollary to this is that PBR better focuses the utility on the achievement of dynamic efficiency gains by optimizing its investment over time in capital, cost reducing innovation, and service innovation. [18]

C. Reasonable opportunity to recover prudently incurred costs and earn a fair return.

It is a cornerstone of the regulatory bargain that the utility should be provided a reasonable opportunity to recover its prudently incurred costs and earn a fair return. The legislated mandates of regulators generally require the regulator to ensure the entities it regulates have that reasonable opportunity to recover their prudently incurred costs and earn a fair return, thus resulting in just and reasonable rates. Both COSR and PBR regimes provide for this outcome. The firm under PBR may see more variation in annual returns over the term of the regime but the utility under PBR is afforded the opportunity to earn returns beyond the allowed return for a longer period than the firm under COSR. It is important to note that the regulatory bargain does not guarantee a return, nor does it guarantee that equivalent returns will be forthcoming every year over the term of the regime.

D. Utility should not benefit from nor be penalized for events outside its control

COSR regimes generally deal with significant events outside the utility's control by bringing the regime to a close and commencing a new revenue requirement proceeding. However, some matters such as fuel

[18] Weisman, Dennis. "A Report on the Theory and Practice of Performance-Based Regulation." SSRN, 2021, papers.ssrn.com/sol3/papers.cfm?abstract_id=3765691., Page 12.

adjustment clauses or storm cost recovery may be dealt with as an element of the COSR regime or in a separate proceeding with a subsequent adjustment to the previously approved revenue requirement.

The stay-out provision in a PBR plan does not allow for (or at least strongly discourages) the utility from coming in with a fresh application, even in the face of significant events outside of its control. PBR plans therefore include provisions for adjustments stemming from significant exogenous events such as exogenous adjustment factors, re-openers, flow-through elements; all of which will be discussed in this study. One of the challenges in the development of a PBR plan is determining the degree to which events are indeed outside the control of the utility and the magnitude required to trigger consideration by the regulator.

E. Be understandable to stakeholders

Some critics of PBR claim that it is abstruse. This criticism is likely exaggerated. The economic regulation of utility rates is an esoteric exercise under both COSR and PBR. The challenge for many stakeholders is that COSR is an accounting exercise, while PBR is an exercise in applied economics. Neither approach is easily understood by the uninitiated, and PBR is sometimes not easily understood by those who have been immersed only in COSR. However, although total factor productivity and benchmarking studies are complex, the fundamentals of PBR are quite easily understood, as will be explained throughout this report. A utility can help stakeholders to understand its proposed PBR framework by providing a clear explanation of the mechanics of PBR, explaining how it achieves the regulator’s objectives, and engaging in workshops and information sessions.[19]

F. Avoid regulatory burden and streamline regulation

The stay-out provision in a PBR plan is intended to reduce regulatory burden by reducing the number of proceedings that would ordinarily be required under COSR and to provide a longer period over which the firm can focus on efficiency gains. However, at the outset of a PBR plan, regulatory burden may not be immediately reduced substantially and may, in some instances, increase the number of proceedings relative to COSR for a period of time. However, a well-designed PBR plan can and should reduce regulatory burden over time and streamline the regulatory process by building in self-adjusting mechanisms such as the I-X formula, streamlining monitoring and limiting the number of annual filings.

G. Make parties better off so that all stakeholders share in the benefits

The stay-out provision coupled with the annual revenue adjustment formula in a PBR plan provide consumers with the benefit of more predictable ex ante rates over a longer period. In addition, some elements of a PBR plan, such as an earnings sharing mechanism, allow for a more immediate sharing of

[19] If you can’t explain what you are doing in simple English, you are probably doing it wrong. (Alfred Kahn).

benefits between the utility and its customers. The available evidence[20] supports the contention that utilities under a PBR regime either reduce their rates on average over the PBR term or increase rates on average at a slower pace than would be expected under COSR. The effect of PBR on utility performance is discussed in a later section of this study.

H. Consider the unique circumstances of the utility

Circumstances among utilities may differ significantly based on relative size, geographic and demographic characteristics, load profile (the mix of residential, commercial, and industrial load), capital replacement cycles, and the effect of policy and legislative obligations, among others. Any regulatory regime must be attuned to the unique circumstances of the regulated utility to ensure that the firm will be provided the opportunity to recover its prudently incurred costs and earn a fair return. A "one size fits all" approach to regulation will not achieve this objective. When the elements of a PBR plan work together to adapt the plan to a utility's circumstances, the utility may be better incentivized and enabled to achieve the expected efficiency gains and other policy objectives. Alternatively, if a regulatory regime does not adequately address the unique circumstances of a utility, it may be unduly constrained in its ability to recover its prudent costs and earn its fair return, let alone achieve efficiency gains to the benefit of both the firm and its customers. In such circumstances, the utility may be compelled to engage in short term unsustainable cost cutting measures that must be recaptured in a subsequent regulatory period.

X. Sharing the Benefits and Risks of PBR

One of the fundamental principles of PBR is that customers share in the benefits of incentive regulation. These benefits may include a slower pace of rate increases and more rate stability than under COSR, assuming a longer stay-out period. Consumers also benefit when the productivity gains achieved in the current regime are accounted for in a subsequent regime and passed on to consumers in potentially lower rates. Under PBR, if earnings fall below the allowed return the utility must absorb the decline in earnings because it cannot obtain rate relief during the stay-out period. As a result, the financial risks to the firm under PBR may be material. This raises the question of how both the benefits and risks of a PBR plan can be shared equitably between utility customers and shareholders, also recognizing that the regulator has an obligation under the regulatory bargain to not knowingly impair the financial integrity of the firms it regulates.

One approach to the equitable sharing of risk is to adjust the utility's allowed return to account for the assumed increase in risk under PBR, usually when the going-in revenue requirement and base rates are set. In any event, the fair return standard dictates that if the risk to return characteristics of the utility under PBR are altered, the allowed return for going-in rates should be adjusted accordingly. In addition,

[20] Crowley, Nick, and Mark Meitzen. "Measuring the Price Impact of Price-Cap Regulation among Canadian Electricity Distribution Utilities." Utilities Policy, vol. 72, 2021, p. 101275., https://doi.org/10.1016/j.jup.2021.101275. Also see: Alberta Utilities Commission Decision 26356-D01-2021 Evaluation of Performance-Based Regulation on Alberta (June 30, 2021)

certain elements of a well designed PBR plan can be adopted to reduce the utility's risk exposure and to ensure that any earnings attrition is not so severe that the financial integrity of the firm is in peril. These PBR elements include Z factors, re-openers, and earnings (and risk) sharing mechanisms (all of which are explained later in this report) that are intended to equitably share both the benefits and risks of PBR between customers and shareholders.

XI. Generic Revenue and Price Cap Formulas under Incentive Regulation

PBR formulas directly regulate the prices or revenues of utilities, rather than their profits, with the goal of improving the incentives for achieving efficiencies and cost savings. Indexed PBR formulas constrain the allowable price (or revenue) increases for the utility to the level expected for a comparable group of utilities based on the expected productivity growth of the comparable group of utilities. In this way, a typical PBR plan rewards a utility that is highly productive relative to the comparison group through higher profits, thus providing stronger incentives to achieve cost efficiencies than ordinarily provided under COSR. In contrast, a typical PBR plan penalizes a utility that is less productive relative to the comparison group through lower profits, thus providing stronger incentives to improve performance than ordinarily provided under COSR.

Indexed PBR formulas can cap the *prices* at which utilities sell their services and permit the firm to maximize its profits, contingent on meeting the price cap on individual services. Alternatively, indexed PBR formulas can cap *revenues* instead of prices, either in the form of a cap on overall revenues, or as a cap on per customer revenues. Indexed PBR formulas are usually augmented with other elements to provide additional constraints or additional latitude to balance the objectives of PBR discussed above, for example to ensure that the utility does not unduly benefit from nor be unduly penalized for events outside of its control. There are several implementation alternatives for each of these approaches. For example, less formal PBR frameworks may target only some aspects of the utility's costs—*e.g.*, certain O&M expenses or certain capital expenses—while regulating other costs through more traditional COSR means (partial indexing).[21]

The generic formula for a price cap is in the form:

$$Price_t = (Price_{t-1} \times (1 + I_t - X)) - CD + Y_t + Z_t + K_t + ESM_t$$

Where:

Price = the price for an individual product or service

t = the period (year)

I = an inflation factor

[21] Hydro-Quebec TransÉnergie's PBR formula applies only to its non-capital-related expenses.

X = a productivity factor

CD = a consumer dividend (stretch factor)

Y = a factor for flow through adjustments

Z = a factor for exogenous adjustments (for matters outside the utility's control)

K = a factor for supplemental capital

ESM = an earnings sharing mechanism

Price capped PBR formulas are usually adopted when the utility is expected to experience significant customer and/or service and product growth over the stay-out period. For example, when PBR was adopted for telephone companies in the 1980's and 90's price cap formulas were typically used in recognition of the significant growth experienced in the telecoms sector.

The generic formula for a revenue cap is in the form:

$$Revenue_t = (Revenue_{t-1} \times (1 + I_t - X + CG)) - CD + Y_t + Z_t + K_t + ESM_t$$

Where:

Revenue = the total annual revenue of the utility

t = the period (year)

I = an inflation factor

X = a productivity factor

CG = a customer growth factor

CD = a consumer dividend (stretch factor)

Y = a factor for flow through adjustments

Z = a factor for exogenous adjustments (for matters outside the utilities control)

K = a factor for supplemental capital

ESM = an earnings sharing mechanism

Revenue capped PBR formulas limit the change in the allowed overall revenue from one year to the next and have been adopted when the utility has conservation initiatives, demand side management mechanism, or when the utility may be expected to undertake a rate redesign during the stay-out period.

The generic formula for a revenue per customer cap is in the form:

$$\frac{\mathrm{Revenue}_t}{\mathrm{Customer}_t} = \left(\frac{\mathrm{Revenue}_{t-1}}{\mathrm{Customer}_{t-1}} \mathrm{x}\ (1 + \mathrm{I}_t - \mathrm{X})\right) - \mathrm{CD} + \mathrm{Yt} + \mathrm{Z}_t + \mathrm{K}_t + \mathrm{ESM}_t$$

Where:

Revenue = the total annual of the utility

Customer = the total annual number of customers

t = the period (usually the year)

I = an inflation factor

X = a productivity factor

CD = a consumer dividend (stretch factor)

Y = a factor for flow through adjustments

Z = a factor for exogenous adjustments (for matters outside the utilities control)

K = a factor for supplemental capital

ESM = an earnings sharing mechanism

A revenue-per-customer cap PBR formula functions much like the revenue cap discussed above. However, instead of limiting the change in the allowed overall revenue from one year to the next, it limits the change in a company's revenue per customer on a class-by-class basis. Revenue-per-customer caps are usually adopted when the average revenue-per-customer for most customer classes is expected to grow or decline substantially from one year to the next over the stay-out period. In these circumstances, a revenue-per-cap avoids revenue excesses or shortfalls. However, a revenue cap PBR formula with a positive or negative growth factor, as appropriate, will provide essentially the same revenue as a revenue-per-customer cap.

XII. Price Caps or Revenue Caps

Revenue-per-customer caps have been applied almost exclusively to gas distribution utilities, recognizing that per customer usage has been declining annually in most jurisdictions due to demand side management and energy efficiency measures. Currently in the U.S. PBR plans for electric distribution utilities and the vertically integrated utilities in Hawaii[22] are all revenue cap plans. The United Kingdom's electric distribution and transmission utilities operated under a price cap from the early 1990s until

[22] The nomenclature of the plan adopted by the Hawaii PUC differs somewhat. The plan includes an Annual Revenue Adjustment in the form ARA = (I - X) + Z – CD, which restricts changes in total annual revenue for each of the Hawaii Electric Company subsidiaries.

2013. The price cap plans in the United Kingdom were replaced by a revenue cap mechanism in 2014. Distribution utilities in New Zealand and Australia are all rate regulated under revenue cap plans.

Canadian PBR rate setting plans have for the most part been price cap plans. Alberta has adopted price caps in three consecutive PBR decisions for its electric distribution utilities.[23] Ontario is unique in its approach. Given the significant number of regulated electric utilities of various sizes in the province, the Ontario Energy Board offers a menu of three alternatives to utilities, two of which have annual adjustment mechanisms in the form of a price cap index, while the third is a forecast-based COSR regime. Utilities are permitted to apply for any one of the three rate adjustment plans.[24]

Table 1 below provides an overview of the PBR plan types in North America, the UK, Australia, and New Zealand.

Table 1: Survey of PBR Plan Types for Electric Companies

Jurisdiction	Company(ies)	Service Type	PBR Plan Type
Massachusetts	Eversource	Distribution	Revenue Cap
Massachusetts	National Grid	Distribution	Revenue Cap
Hawaii	Hawaii Electric Companies (3)	Vertically Integrated	Revenue Cap
Alberta	Distribution Companies (4)	Distribution	Price Cap
Ontario	Distribution Companies (61)	Distribution	Menu with Price Cap Options
Quebec	Hydro-Quebec TransÉnergie	Transmission	O&M Revenue Cap
United Kingdom	Distribution Companies (6)	Distribution	Revenue Cap
Australia	Distribution Companies (17)	Distribution	Revenue Cap
New Zealand	Distribution Companies (13)	Distribution	Revenue Cap

XIII. Going-in Base Rates/Revenues

Each of the PBR formula types discussed above commences from a base year revenue requirement that dictates the going-in prices or overall revenue (at year t) to which the PBR formula is initially applied. The objective in calculating the base year amount(s) is to ensure that the going-in rates are just and reasonable and not reflective of monopoly profits, as the I-X formula produces just and reasonable rates

[23] Prior to adopting PBR plans in 2013 (Decision 2012-237), the Alberta Utilities Commission approved an indexed formula-based plan that capped prices for ENMAX Distribution and capped the revenue for ENMAX Transmission. (Decision 2009-035)

[24] There are some notable exceptions in Ontario. Hydro One distribution and Hydro One Transmission, with 97% of transmission assets in Ontario, both operate under a revenue cap. See, "Application for electricity transmission revenue requirement beginning January 1, 2019, and related matters," Hydro One Sault Ste. Marie, LP. Decision and Order EB-2018-0218. June 20, 2019.

only to the extent that the going-in rates are just and reasonable. There are two broad approaches that regulators have employed to establish base year revenue requirements.

The first approach is to select an historical representative year, usually the year prior to the first year of the PBR plan, without adjustments for specific items such as non-recuring expenses. For example, the base year revenues for the Hawaii PBR plans were the existing allowed revenues on the last date before the PBR tariff became effective. In some cases, if the revenue requirement is to be rebased between two PBR regimes, there is a gap year between PBR terms for which a revenue requirement is established that becomes the base year revenue requirement for the subsequent PBR regime. The Alberta Utilities Commission approved rates for 2023 on a forecast COSR basis, ostensibly accounting for the efficiency gains in the prior PBR period. The approved 2023 rates served as the base rates for the price cap PBR regime commencing in 2024.

The second approach, which is now common in most U.S. PBR plans, is to select an historical representative year, adjusted for specific investments or other expenses depending on whether those adjustments are representative of the revenue requirement expected in at least the first year of the subsequent PBR plan. For example, in the 2017 PBR decision for Eversource, the Massachusetts Department of Public Utilities (DPU) used an historic test year adjusted for known and measurable changes to establish the base year revenue requirement and base rates. The DPU determined that certain investments were to be included or excluded from base revenues, depending on whether those investments were deemed representative of future investments during the subsequent PBR term.[25]

One notable exception was adopted by the Alberta Utilities Commission for the 2018 to 2022 PBR regime.[26] The going in rates were established based on a notional 2017 revenue requirement using actual costs and capital additions. The utilities were directed to file an application to determine a notional 2017 revenue requirement to be used to determine the going-in rates for the 2018 PBR plans, using actual pre-2017 capital-related costs to develop a notional 2017 revenue requirement, adjusted as required for anomalies.[27] O&M costs for the notional 2017 revenue requirement were based on the lowest O&M cost year during the preceding PBR term, restated to 2017 dollars, with adjustments as necessary to reflect material anomalies specific to that year.[28]

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[25] Massachusetts Department of Public Utilities, *Order Establishing Eversource's Revenue Requirement,* Docket D.P.U. 17-05, November 30, 2017, 4-5

[26] Decision 20414-D01-2016

[27] Anomalies were not well defined in the decision, but were intended to adjust actual pre-2017 costs for known and measurable changes.

[28] Again, anomalies are not well defined in the decision and follow-up proceedings invited applications to approve anomalies for each utility. In Decision 24325-D01-2020 the Commission rescinded the five criteria set out in Decision 22394-D01-2018 that must all be met to qualify as an anomaly for rebasing purposes and provided clarification regarding the concept of an anomaly adjustment for the purposes of rebasing. Subsequently, in Decision 25422-D01-2020 the Commission considered anomaly applications from the utilities. Only one application for an anomaly was accepted: a capital retirement anomaly for ENMAX.

Figure 2 below shows the approach to determining base rates in each in each state in the United States.

Figure 2: Approach to Determining Base Rates in the U.S. [29]

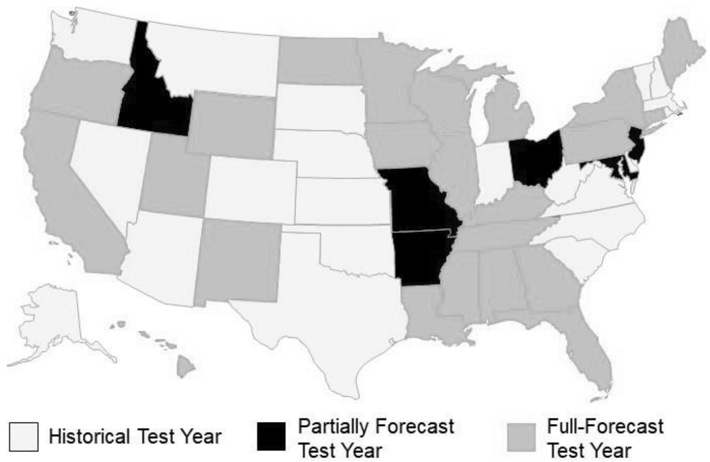

Table 2 below sets out an overview of the base year methodologies adopted for indexed PBR plans in North America.

[29] Source: *Guidehouse*

Table 2: Survey of Base Year Methodologies in Recent North American Indexed PBR Plans

Jurisdiction	Company(ies)	Base Year	Methodology
Massachusetts	Eversource	2020	Historic test year adjusted for known and measurable changes
Massachusetts	National Grid	2019	Historic test year adjusted for known and measurable changes
Hawaii	Hawaii Electric Companies (3)	2020	Going in revenues are the allowed revenues on the last date before the PBR tariff becomes effective
Alberta	Distribution Companies (4)	2023	Approved 2023 rebased COSR rates serve as the base rates when PBR tariff becomes effective[30]
Ontario	Distribution Companies (61)	Varies[31]	Going-in rates set on a revenue requirement derived from future test year or historic year[32]
Quebec	Hydro-Quebec TransÉnergie	2019	Historic base year with non-recurring expenditures excluded

XIV. Stay-Out Period

An important feature of indexed PBR plans is the stay-out period (term) of the plan. In most PBR plans, the utility agrees to a stay-out period during which it undertakes not to return with an application to adjust its rates or reset the parameters of the PBR plan. The stay-out period should be long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues are substantially out of alignment with costs. A stay-out period that exceeds the normal duration of time between COSR rate cases is one of the elements of a PBR plan that incentivises the utility to seek out greater efficiencies. This is because the utility is required to live under the constraints of the annual cap

[30] The Alberta utilities operate under a price cap, rather than a revenue cap, so going-in utility prices, not revenues, are set for the base year.

[31] Because the Ontario energy Board regulates 61 companies with a menu approach, as discussed above, the base years vary across companies and dependent on the regulatory alternative.

[32] For the Ontario utilities that operate under a price cap, rather than a revenue cap, going-in utility prices, not revenues, are set for the base year. Base rates are set through a cost-of-service process for the first year. In those cases where a utility operates under a revenue cap (e.g. Hydro One Transmission) going in revenues are set for the base year.

and because the utility is permitted to keep a portion of any earnings beyond the allowed return for the duration of the stay-out period.

The stay-out period in the majority of PBR plans is five years. However, in some cases the stay out period is longer than five years. For example, NSTAR Gas in Massachusetts is currently operating under a ten-year stay-out period.[33] Table 3 below sets out an overview of PBR stay-out periods for electric companies.

Table 3: Survey of PBR Plan Stay-Out Periods for Electric Companies

Jurisdiction	Company(ies)	Service Type	Stay-Out Period
Massachusetts	Eversource	Distribution	5 years
Massachusetts	National Grid	Distribution	10 years
Hawaii	Hawaii Electric Companies (3)	Vertically Integrated	5 years
Alberta	Distribution Companies (4)	Distribution	5 years
Ontario	Distribution Companies (61)	Distribution	Minimum 5 years
Quebec	Hydro-Quebec TransÉnergie	Transmission	4 years
United Kingdom	Distribution Companies (6)	Distribution	5 years
Australia	Distribution Companies (17)	Distribution	5 years
New Zealand	Distribution Companies (13)	Distribution	5 years

XV. Inflation Factor

An indexed PBR formula is designed to produce rates that reflect the rate of inflation in input prices faced by the utility from year to year during the term of the plan, less an adjustment for expected productivity. The inflation factor captures the changes in utility input prices driven by macro-economic forces beyond the utility's control. There are two approaches generally used to develop an inflation index in PBR plans.

The first approach is to use a measure of economy-wide *output* price inflation. Output price measures reflect the prices of goods and services purchased by consumers. The Gross Domestic Product Price Index (GDP-PI) is commonly used as a measure of output price inflation for PBR plans in the United States.

The second approach uses a measure of industry *input* price inflation. An input price measure of inflation captures the prices of the specific inputs purchased by the utility. Canadian PBR plans generally use an input inflation measure that combines labor and non-labor price indexes into a weighted average to

[33] Massachusetts Department of Public Utilities, Petition of NSTAR Gas Company doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Mechanism, D.P.U. 19-120, October 30, 2020, 65.

account for changes in the price of labor, materials, and other inputs. For example, the PBR plans in Alberta have generally used a measure of inflation in the form: [34]

I_t = 55% x AWE_t-1 + 45% x CPI_{t-1},

where:

I_t = Inflation factor for the following year.

AWE_{t-1} = Alberta average weekly earnings index for the previous July through June period.

CPI_{t-1} = Alberta consumer price index for the previous July through June period

The Ontario Energy Board used a similar input price measure; however, the non-labor component of inflation is captured by the province's GDP implicit price index ("GDP-IPI").

Table 4 below sets out an overview of the inflation measures adopted in several jurisdictions.

Table 4: Survey of PBR Inflation Index Factors for Electric Companies

Jurisdiction	Company(ies)	Input / Output	Measure
Quebec	Hydro-Quebec TransEnergie	Input	Composite of Labour Earnings and CPI
Alberta	Alberta Distribution Companies (4)	Input	Weighted Average Labour Earnings and CPI
Ontario	Ontario Distribution Companies (61)	Input	Weighted Average Labour Earnings and GDP-IPI
Massachusetts	National Grid	Output	GDPPI
Massachusetts	Unitil (pending)	Output	GDPPI
Connecticut	Eversource (pending)	Output	GDPPI
Hawaii	Hawaiian Electric Companies (3)	Output	GDPPI
United Kingdom	UK Distribution Companies (6)	Input	CPI Incl Housing Costs (CPIH)[35]
New Zealand	NZ Distribution Companies (17)	Input	CPI
Australia	AUS Distribution Companies (13)	Input	CPI

[34] The relative weights between labor and materials vary between companies and PBR plans.

[35] Originally, the index was CPI, but was subsequently changed to CPIH because it was deemed to be a more relevant measure.

XVI. The Relationship Between I and X

As discussed above, the inflation factor may be a measure of economy-wide output inflation, such as GDP-PI as commonly used in U.S. revenue or price caps. Alternatively, the inflation factor may be an industry-specific input measure of inflation meant to track changes in industry labor and non-labor costs. As explained in the next section of this report, the productivity factor (X) is derived from a total factor productivity calculation that measures productivity growth in the relevant utility sector. The inflation factor ("I") in a revenue/price cap has an important implication for how the TFP results are used to derive an economically appropriate X-Factor.

When the inflation measure used to calculate the inflation factor in the PBR formula is industry specific, then the X factor is equal to the Total Factor Productivity growth for the relevant industry:

$$\text{X-Factor} = \text{TFP growth}_{\text{Industry}}$$

However, when the inflation factor in the PBR formula is a measure of economy-wide output inflation, such as GDP-PI, then the derivation of the X factor is adjusted because the X-Factor formula is a function of the inflation measure used in the price/revenue cap. When the inflation index is an economy-wide measure of inflation the X-Factor is calculated as follows:

$$\text{X-Factor} = (\text{TFP growth}_{\text{Industry}} - \text{TFP growth}_{\text{Economy}}) + (\text{Input Price growth}_{\text{Economy}} - \text{Input Price growth}_{\text{Industry}})$$

XVII. Derivation of the Empirical X Factor

A primary goal of economic regulation is to regulate so that economic outcomes mimic the outcomes that would be observed in a competitive market. In competitive markets, economic profits[36] tend to zero in the long run. This is the starting point for price cap regulation. The long run zero profit condition under competition implies that average output price equals the cost the firm pays for the inputs needed to produce a unit of that good or service, accounting for the firm's productivity; in other words, the efficiency of turning inputs into outputs.

Starting from that basic assumption, the cap used in price cap regulation is calculated to reflect what one would expect to observe in competitive markets in the long run. Output prices are set to equal input prices minus productivity (I-X in the price cap formula), where I represents inflation and X represents industry-wide productivity growth. The I-X formula means that average prices for capped goods/services are adjusted for inflation (I), less the expected productivity growth over the relevant period, typically representative of an industry average (X). In essence, the allowed price changes mimic changes in average unit costs. In competitive markets, both I and X are external and outside the control of the firm. Thus, the price cap formula for the regulated firms should likewise be external and exogenous to the regulated firm.

[36] Economic profit is a financial metric that considers both explicit costs and opportunity costs to provide a more comprehensive view of a business's profitability. Economic profit = revenues – (explicit costs + opportunity costs).

XVIII. Calculating Industry Average Productivity Growth

Industry average productivity growth is estimated in a total factor productivity (TFP) study. TFP is simply the ratio of total outputs to total inputs in the production process of the firm. Total factor productivity growth is therefore the difference between the growth in outputs and the growth in inputs over time, calculated based on a year over year index of output and input growth.

TFP growth = (output growth) minus (input growth)

The output growth measure for an electric distribution company may be MWh, MW, or customers calculated as an index of the annual change in the applicable output measure for each company in a large sample of comparable companies. When revenues are capped in a PBR plan, the usual practice has been to use the number of customers as the output measure. When prices are capped in a PBR plan, MWh has generally been used as the measure of output, however in some instances the number of customers has also been used. The decision as to whether MWh or the number of customers, or a weighted average of the two, is used as an output measure for price cap plans is usually determined based on the relative weight ascribed to demand and usage charges in the rate structure of the company.

The input growth measure for an electric distribution company is the weighted average of the annual change in labor, materials, rents and services,[37] and capital calculated as an index for each input for each company in the large sample of comparable companies, weighted by each input's relative share of total costs for the company.

An assumption must be made about the usefulness of capital assets as a productive input over their lives (referred to as capital service). TFP theory and practice identify three different capital service methodologies that model how capital services may decay (lose their productive efficacy) over time. The three models are one-hoss shay[38] which assumes no decay over time; geometric decay which assumes more decay occurs in the early years than in later years; and hyperbolic decay which assumes more decay occurs in the later years than in the early years. There is no *a-priori* theoretical guidance as to the impact that the choice of capital services methodology has on TFP or X-Factor growth results.

With respect to non-capital expenses, in a distribution utility TFP study, practitioners debate whether customer accounts expenses should be included. The norm in TFP studies for distribution utility TFP studies has been to include customer accounts expenses because they can be causally assigned to the distribution and retail business. On the other hand, including general and administrative expenses and general plant has much less theoretical support for inclusion in a distribution utility TFP study because there is not an economically correct methodology for allocating these expenses to the distribution and

[37] Rents and services include non-wage O&M expenses.

[38] The term One Hoss Shay derives from a poem by Oliver Wendell Holmes about a carriage that served its owner daily over its life. In economics, the term is used to describe a model of depreciation in which a durable product delivers the same services throughout its lifetime before failing, with zero salvage value.

retail business. Accordingly, whether these expense categories should be included in the input growth measure for an electric distribution company is a matter of debate.

Data sources for the components of input growth and output growth in TFP studies are generally derived from publicly available data bases. Table 5 below sets out an overview of some common data sources employed in TFP studies.

Table 5: Common Data Sources for Electric Company TFP Studies

Category	Components	Source
Input Costs	Labour Materials and Services (M&S) Capital	FERC Form 1 (SNL Financial & Raw FERC Form 1 files) Energy Information Administration (Form EIA- 860)
Output Quantities	MWh MW Customers	FERC Form 1 (SNL Financial & Raw FERC Form 1 files)
Price Index	Labour Price Index Wage Levels Capital Price Index M&S Price Index Depreciation Rate Cost of Debt Return on Equity	Employment Cost Index – US BLS Occupational Employment Statistics – US BLS Whitman, Requardt, Associates, LLP US Bureau of Economic Analysis (BEA) US BEA FERC Form 1 (SNL Financial) Regulatory Research Associates

The results of recent TFP studies are set out in Table 6 below. However, it should be noted that the results of TFP studies cannot be compared across jurisdictions because of differences in the measure of inflation, the type of utility and whether the TFP study relates to a price cap or revenue cap PBR plan. Nonetheless, the results of recent studies provide an indication of the range of expected productivity growth in the electric utility sector.

Table 6: Results of Recent TFP Studies for Electric Distribution Utility PBR Proceedings

Jurisdiction	TFP Growth	Period	Output Measure
Alberta 2023 (Distribution)	**0.002% (NERA)**	**1972-2021**	**MWh**
	0.08% (PEG)	**2007-2021**	**Customer**
	-1.084% (Christensen)	**2007-2021**	**MWh**
	Commission Decision: Range between -0.28% and -0.51%		
MA 2022 (Distribution)	**0.06% (Christensen)**	**2006-2020**	**Customer**

Although a TFP study using a sample of peer companies is typically used to determine the X factor, other methods can be employed. For example, the firm's own input and output data can theoretically be used to derive a company-specific productivity growth estimate if the utility was unaware that its historical performance would be used to determine productivity growth for a future PBR plan. This would only be applicable in a first generation PBR plan. Alternatively, the Kahn Method calculates a productivity growth estimate based on financial data as opposed to the outputs measured in TFP growth studies.[39] This method has been employed in the price cap regulation of U.S. oil pipelines, as well as periodically elsewhere.

XIX. Determining the X Factor

The TFP study discussed above provides an empirical estimate of the historical rate of productivity growth in the relevant industry, in this case electric distribution utilities. Setting the X Factor equal to expected industry productivity growth provides incentives for productivity gains and cost mitigation by the regulated firm. However, although the X factor should ideally align with the empirical evidence on productivity growth, the X factor set by a regulator for a PBR plan may depart from the TFP-derived productivity growth estimate to achieve certain objectives under the plan. For example, in recent PBR plans in Massachusetts and Alberta, the X Factor was set at zero to provide for a large consumer dividend (stretch factor) despite evidence that average industry productivity growth is negative. There is a balance to be struck when setting an X Factor that strays from the empirical evidence on productivity growth to preserve both the practical and the theoretical foundations of incentive regulation to the greatest possible extent while satisfying other objectives of the regulator.

Table 7 below sets out an overview of recent X Factors, excluding any explicit consumer dividend (stretch factor), for PBR plans and the methodology used by the regulator in several jurisdictions. As discussed further below, when the X factor is set at zero, despite evidence that average industry productivity growth is negative, the result is an implicit consumer dividend equivalent to the amount of the negative empirical X factor that was calculated in the relevant TFP study.

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[39] The U.S. Federal Energy Regulatory Commission ("FERC") uses the "Kahn X-factor" methodology for setting the maximum allowed tariffs for U.S. oil pipelines. The Kahn methodology derives the X-factor residually by comparing an economy-wide inflation measure—the Producer Price Index for Finished Goods ("PPI")—to the growth in oil pipeline costs. The FERC has been regulating U.S. oil pipeline tariffs under the Kahn X-factor methodology since 1995; see Revisions to Oil Pipeline Regulations Pursuant to Energy Policy Act of 1992, Order No. 561-A, July 28, 1994, Docket No. RM93-11-001, 18 CFR 341, 18 CFR 342, 18 CFR 343, 59 FR 40243.

Table 7: X Factors in Recent PBR Decisions for Electric Utilities

Jurisdiction	Company(ies)	Year	X Factor	Methodology
Quebec	Hydro-Quebec TransEnergie	2023	0.57%	Kahn Method + TFP Studies + Regulator Judgement
Alberta	Distribution Companies (4)	2023	0.1 %	TFP Study + Regulator Judgement
Ontario	Ontario Distribution Companies (61)	N/A	0 %	TFP Studies
Hawaii	Hawaiian Electric Companies (3)	2021	0%	Kahn Method + Regulator Judgement
Massachusetts	Eversource	2022	0%	TFP Study + Regulator Judgement
Massachusetts	National Grid	2021	-1.72%	TFP Study
New Zealand	NZ Distribution Companies (17)	2020	0%	Regulator Judgement

XX. Consumer Dividend (Stretch Factor)

A consumer dividend in indexed PBR plans, also known as a "stretch factor," is intended to do two things. First, a stretch factor is usually applied to the PBR formula in first generation PBR plans to immediately share *with consumers the efficiency gains from the PBR plan that a utility is* expected to achieve ("low hanging fruit") when first under a new incentive structure. Second, a consumer dividend is often applied to an indexed PBR plan (whether a first generation PBR plan or not) to more immediately share some of the annual productivity gains with customers throughout the stay-out period to provide for an equitable sharing of benefits. In both cases, a consumer dividend reduces revenue increases annually to provide customers with some rate relief.

The consumer dividend may be established by regulatory judgement and precedents in other jurisdictions, as well as with reference to a cost benchmarking study that compares the utility's unit costs with the unit costs of a group of peer companies. In the latter approach, the assumption is that a company's cost performance relative to its peers indicates its ability to achieve incremental efficiency gains under the plan. A company with higher unit costs or unit cost growth relative to its peers may have more ability to cut costs further, which may be accounted for in the consumer dividend. Conversely, a company with lower unit costs relative to its peers may have less capacity to cut costs. In this scenario, a stretch factor may be potentially problematic if the resulting annual revenue falls below the needs of the company. Therefore, when a stretch factor is informed by a benchmarking study the magnitude of the stretch factor should be related to the company's relative excess unit costs. In some cases, however, the consumer dividend is informed by judgment on the part of the regulator, rather than quantitative analysis.[40]

[40] In the first PBR plans approved by the Alberta Utilities Commission, the stretch factor has been based on regulator judgment.

In some jurisdictions stretch factors are typically included as a component of the X factor. The X factor is adjusted upward to provide for the stretch factor, and an explicit consumer dividend is excluded from the PBR formula. Recently, several capped PBR plans have approved an X factor of zero percent, as noted in Table 9, and as discussed above. When the X factor is set at zero, despite evidence that average industry productivity growth is negative, the result is an implicit consumer dividend equivalent to the amount of the negative empirical X factor that was calculated in the relevant TFP study. In a few cases, the regulator has included an additional explicit consumer dividend in the PBR formula, even when the X factor has been set at zero. However, as discussed above, it is important to consider the capacity of the utility to achieve incremental efficiency gains under the plan when determining a consumer dividend that is both achievable and equitable for both consumers and the company.

Table 8 below sets out an overview of the consumer dividend in capped PBR plans in several jurisdictions.

Table 8: Consumer Dividends (Stretch Factors) in Recent PBR Decisions for Electric Utilities

Jurisdiction	Company(ies)	Year	X Factor	Consumer Dividend / Stretch Factor
Quebec	Hydro-Quebec TransEnergie	2023	0.57%	Zero
Alberta	Distribution Companies (4)	2023	0.1 %	Integrated into X factor, implicit stretch factor equal to negative empirical X factor plus explicit consumer dividend of 0.3 %
Ontario	Ontario Distribution Companies (61)	N/A	0%	0.0% to 0.6%
Hawaii	Hawaiian Electric Companies (3)	2021	0%	Stretch = ARA Revenues compounded by 0.22% annually + $22.16 Million [41]
Massachusetts	Eversource	2022	0%	Consumer Dividend = 25 Basis points when inflation >2%
Massachusetts	National Grid	2021	-1.72%	Stretch = 0.4%. 0% of Stretch when inflation <1%. 50% of Stretch if 1% < inflation < 2%. 100% of Stretch when 2% > inflation

[41] The consumer dividend is made up of a 0.22% annual compounding factor applied to the Annual Revenue Adjustment plus an additional $22.16 million, representing HECO's prior commitment to return $25 million in annual savings because of a management audit conducted in HECO's last general rate case, determined on a cash basis, and averaged over the multi-year rate plan.

XXI. Determining a Growth Factor

As explained earlier, PBR formulas that cap overall revenue should theoretically include a customer growth factor to adjust for incremental (decremental) revenues from new (lost) customers that would otherwise not be accounted for, thereby either over- or under-funding the utility. The customer growth factor in the formula is usually expressed as an annual percentage that reflects the change in customer accounts, MW or MWh depending on the output measure in an accompanying TFP study to adjust total revenue as a percentage change in the same manner as the inflation factor. However, there are variations to this approach. In some cases, the growth factor is applied to O&M revenues only, and then escalated by the inflation factor. Also, although the growth factor may be based on the actual growth in the prior period, average growth over several preceding years or forecast growth may also be used.

In a few recent revenue capped PBR plans, the growth factor has been excluded from the formula. This has the effect of increasing the consumer dividend (stretch factor) by the amount of the growth factor (assuming incremental growth is forecasted). In other words, in the absence of a growth factor, the utility is required to absorb the increased costs associated with any output growth. The additional costs are excluded from the adjustment in rates.

Table 9 below sets out an overview of the growth factors in Revenue capped PBR plans in several jurisdictions.

Table 9: Survey of Growth Factors in Recent Revenue Capped PBR Plans

Jurisdiction	**Company(ies)**	**Service Type**	**Growth Factor**
Massachusetts	Eversource	Distribution	Excluded
Quebec	Hydro-Quebec TransEnergie	Transmission	Included to account for operating expenses associated with capital investment
Massachusetts	National Grid	Distribution	Excluded
Hawaii	Hawaii Electric Companies (3)	Vertically Integrated	Excluded

XXII. Y (Flow Through) Factor

The purpose of Y factors is to allow the utility under PBR to recover *recurring* annual costs that are outside of management's control and therefore, not rightfully constrained by the I-X mechanism in the PBR formula. This is because these costs cannot be managed though efficiency measures, precisely because they are outside of management control. Y factor-related costs are therefore often recovered from customers directly in rates or in some cases refunded to them. Occasionally, PBR plans do not use the term "Y factor" when referring to flow-through costs, but they still include provisions for such costs, sometimes in the form of a tracker, as discussed further below.

Generally, costs must satisfy the following criteria to be considered for Y factor treatment.[42]

- The costs must be attributable to events outside management control.
- The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
- The costs should not have a significant influence on the inflation factor in the PBR formulas.
- The costs must be prudently incurred.
- All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

Revenue capped PBR sometimes exclude a Y factor because the costs to be recovered, although outside of management control, have been accounted for in the going in base rates and are not expected to fluctuate significantly over the PBR stay-out period. However, consistent with the last of the criteria above, when such costs are expected to vary significantly over the stay-out period, the PBR plan may include a Y factor to account specifically for that cost. For example, Hydro-Quebec TransEnergie's revenue capped PBR plan includes a Y factor that specifies retirement costs given their expected unpredictability and variability.

Table 10 below sets out examples of the Y factor elements for several PBR plans.

[42] These specific criteria were adopted by the Alberta Utilities Commission in AUC Decision 2012-237 and have been adopted in much the same form for PBR plans in other jurisdictions.

Table 10: Y Factor elements in Recent PBR Decisions for Electric Utilities

Jurisdiction	Company(ies)	Year	Y Factor Elements
Quebec	Hydro-Quebec TransEnergie	2023	Retirement costs specifically and other costs that satisfy the Y factor criteria subject to a $2.5M materiality threshold
Alberta	Distribution Companies (4)	2023	System operator fees, farm transmission costs, costs arising from Commission directives, tax changes, municipal fees, load balancing deferral accounts, and production abandonment costs
Hawaii	Hawaiian Electric Companies (3)	2021	Costs pertaining to energy costs and purchased power, pension costs, demand-side management costs, renewable energy infrastructure program costs
Massachusetts	Eversource	2022	No Y Factor
Massachusetts	National Grid	2021	No Y factor

XXIII. Z (Exogenous Adjustment) Factor

A Z factor in indexed capped PBR plans allows for the recovery of costs related to *one-time* exogenous events, including force majeure ("act of god") events. The Z factor adjusts utility revenues to account for the significant financial impact (either positive or negative) of a one-time event that is outside of management control and for which the company has no other reasonable opportunity to recover the related costs through another element of the PBR formula.

The criteria for a Z factor are much the same across PBR plans, with some variation. The criteria are generally as follows:[43]

- The impact must be attributable to some event outside management's control
- The impact of the event must be material. It must have a significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income in the normal course of business
- The impact of the event should not have a significant influence on the inflation factor in the PBR formula

[43] These specific criteria were adopted by the Alberta Utilities Commission in AUC Decision 2009-035and have been adopted in much the same form for PBR plans in other jurisdictions.

- All costs claimed as an exogenous adjustment must be prudently incurred.

Z factor adjustments are usually subject to a materiality threshold in recognition of the second criterion above. And, in some PBR plans the categories of allowable Z factor applications are specified. For example, in Massachusetts these include, but are not limited to, incremental costs resulting from changes in tax laws that uniquely affect the industry, accounting changes unique to the industry, and regulatory, judicial, or legislative changes uniquely affecting the industry.[44]

Table 11 below sets out examples of the Z factor elements and thresholds for several recent PBR plans.

Table 11: Z Factor Thresholds in Recent PBR Decisions for Electric Utilities

Jurisdiction	Specified Elements	Year	Z Factor Threshold
Quebec	Unspecified	2023	$2.5 Million
Alberta	Unspecified	2023	The dollar value of a 40-basis point change in ROE on an after-tax basis calculated on each company's equity used to determine the revenue requirement on which going-in rates were established, escalated by I-X annually
Hawaii	Unspecified	2021	$4 Million
Massachusetts	Changes in tax laws, accounting changes, regulatory, judicial, or legislative changes	2022	$5 Million adjusted annually by GDP-PI

XXIV. K (Supplemental Capital) Factor

It is sometimes noted that PBR helps reduce the "Averch-Johnson effect" of utilities potentially "over-investing" in capital to increase the regulated rate base and thus the allowed profits under cost-of-service regulation.[45] In part this is because the effect relies on several theoretical conditions related to COSR.[46]

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[44] Massachusetts Department of Public Utilities, D.P.U. 17-05

[45] Harvey Averch and Leland L. Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-1069.

[46] The Averch-Johnson effect relies on several theoretical conditions. It assumes that firms are subject to rate-of-return regulation (COSR) and that the allowed return is greater than the required return on capital. The incentive to increase the level of capital beyond what is needed for economically efficient production involves several assumptions about future allowed returns and the future cost of capital; assumptions that may not be realized.

However, the utility under PBR has little if any bias towards capital investment because the company will be restricted in its ability to recover in rates the additional depreciation and return accruing from an over-investment in capital. If a capital investment does not result in immediate ongoing cost efficiencies or increased revenue from load growth, the utility has little incentive under PBR to make the investment. Nonetheless, the most difficult area to determine for an indexed capped PBR plan is the parameter(s) for capital additions during the PBR term.

Capital additions can be difficult to forecast, can vary significantly among companies depending on demand growth and replacement cycles, and may be significantly influenced by legislative and public policy demands on a utility. Although utilities have considerable flexibility in dealing with the timing of their capital programs and can accommodate changes in circumstances, if the capital available to a utility under a PBR plan is unduly restricted, the utility may be constrained in finding sustainable long term productivity gains to the detriment of consumers.

PBR plans have recognized that supplementary capital may be required to provide for additional capital needs not adequately funded by the I-X mechanism. Supplemental capital mechanisms are intended to provide the utility with sufficient capital to satisfy its obligations to provide safe and reliable service, while constrained by the (I-X) mechanism under PBR plans. The objective is to balance the genuine capital requirements of the firm against the assumed risk that the firm will over-invest or under-invest in capital over the PBR term. Supplemental capital may be required when a utility is likely to experience significant load growth over the stay-out period or when it has aging infrastructure that requires replacement, resulting in significant capital additions to serve existing customers. A PBR plan may struggle to adequately align the costs of capital additions with the projected revenue provided by the PBR formula. And when a utility is required to invest in capital additions to facilitate certain public policy objectives, for example electrification objectives that may not result in timely increases in expected load and revenue, earnings attrition may result.

Although capital supplement mechanisms are increasingly common in PBR plans, the approach to supplemental capital factors varies significantly across jurisdictions. However, these approaches fall into two broad categories, capital trackers and indexed capital adjustment mechanisms usually referred to as K-Bar.[47]

Capital trackers are essentially an annual proceeding that focuses on the approval of specific, often targeted, capital additions. The generic form of capital tracker permits the utility to file an application annually for approval to undertake certain capital investments. The criteria for the investments are usually established in advance. Once the capital investments are approved, the utility undertakes them

[47] David Sappington and Dennis Weisman proposed the original concept of a K-Bar factor to ensure any additional forecasted capital expenditures not recovered through the I–X formula (and not due to exogenous events) are included in revenue. Unlike other forms of K-bar, the utility forecasts its controllable capital needs over the term of the PBR plan and the incremental amount of the forecast expenditures that are not expected to be recovered through the I–X formula are recovered through a supplemental capital (F) factor. See David E.M. Sappington and Dennis L. Weisman, “Assessing the Treatment of Capital Expenditures in Performance-Based Regulation Plans”, September 1, 2015, p. 32.

and there is then a subsequent prudence review before the capital related costs are approved for recovery in rates.

For example, the Hawaii PBR plans include an Exceptional Project Recovery Mechanism (EPRM) that provides rate relief for extraordinary projects on a case-by-case basis. The EPRM is a reconciled cost recovery mechanism filed for specified projects. It provides for recovery of allowed revenues for the net costs of approved projects placed in service during the PBR stay-out period. Unlike most capital trackers, the EPRM is applicable to O&M expenses and program costs, not just capital expenditures. The Hawaii cost trackers allow for the recovery of costs pertaining to energy costs and purchased power, pension costs, demand-side management costs, and renewable energy infrastructure program costs; some of which might otherwise be recovered by way of a Y factor.

The Ontario Energy Board PBR plans include two supplemental capital cost recovery mechanisms in the form of specified capital trackers. The incremental capital module ("ICM") allows electric utilities to collect revenues for extraordinary and unanticipated capital spending requirements that are outside the normal course of business.[48] The advanced capital module ("ACM") allows electric utilities to collect revenues related to longer term capital projects subject to prior approval.[49] The ICM and ACM trackers provide for cost recovery when the capital investments go into service, rather than waiting until the next time rates are rebased at the end of a PBR term. At the end of the PBR term, the costs are included in rate base in the next generation PBR going-in base rates.

K-Bar was originally adopted by the Alberta Utilities Commission in its second generation PBR plan.[50] Under this approach, the I-X formula escalates the historical average costs for specified capital additions to form the basis of future approved capital recovery for supplemental capital. Recoverable capital expenditures are obtained from the differential between the utility's escalated historical capital needs and what each utility will collect for the K-bar-related capital under the I-X formula, to avoid double counting. The Commission set out the parameters for the calculation of the 2018 base K-bar factor as the average annual capital additions for 2013 to 2016 for each company. Base K-bar was then inflation-adjusted for the period 2019 through 2022 as follows, with possible adjustments for certain retirements.

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

[49] Ontario Energy Board, *New Policy Options for the Funding of Capital Investments,* EB-2014-0219, September 8, 2014.

[50] Decision 20414-D01-2016

$\text{K-bar}_t = \text{K-bar}_{t-1} + \text{base K-bar} \times (1 + (I_t - X)) * (1 + (I_{t-1} - X))$

Where:

K-bar_t = K-bar factor for current year

K-bar_{t-1} = K-bar from the previous year

Base K-bar = 2018 base K-bar

I_t = inflation factor for current year

I_{t-1} = inflation factor from the previous year

X = productivity factor

$(1 + (I_{t-1} - X)) \ldots = (1 + (I_t - X))$ multipliers for all previous years

This K-Bar approach was adopted in 2023 for Eversource in Massachusetts under its second generation PBR framework.[51] Similar to the approach adopted in Alberta, the Massachusetts K-Bar approach uses a five year fixed historical average to calculate the base K-Bar amount. In addition, the Massachusetts Department of Public Utilities imposed an annual capital spending constraint of up to ten percent relative to the annual capital spending forecasted by Eversource Electric, with any costs over the ten percent cap excluded from the K-bar calculation.

In some cases, both a capital tracker mechanism and a K-Bar mechanism are included in a PBR plan to provide for supplemental capital. The Alberta Utilities Commission, in its second and third generation PBR plans, adopted both a capital tracker and K-bar mechanism by dividing supplemental capital into two categories: Type 1 and Type 2 capital. For Type 1 capital the Commission approved capital trackers for a narrowly defined category of capital. Type 1 capital is defined as capital that does not meet the criteria for a Z factor adjustment but is not a type of capital that the distribution utilities have deployed in the past, for example capital required to comply new government programs. Type 2 capital was subject to the K-bar methodology.

Table 12 below sets out examples of the Supplemental Capital Mechanisms (K Factors) in Recent PBR plans.

[51] Massachusetts Department of Public Utilities, D.P.U. 22-22.

Table 12: K Factors in Recent PBR Decisions for Electric Utilities

Jurisdiction	Year	K Factor
Alberta	2023	Type 1 Capital: capital tracker with narrowly defined criteria recovered in a capita tracker. Type 2 Capital prescribed in a K-Bar mechanism with a fixed five-year average base K-bar amount.
Ontario	N/A	ICM capital tracker recovers costs extraordinary and unanticipated capital spending requirements that are outside the normal course of business ACM capital tracker recovers costs related to longer term capital projects subject to prior approval
Hawaii	2021	Exceptional Project Recovery Mechanism (EPRM): a capital tracker for extraordinary projects on a case-by-case basis. EPRM is applicable to O&M expenses and program costs, as well as capital expenditures
Massachusetts	2022	K-Bar with rolling average five-year base K-Bar amount and a ten percent annual cap

XXV. Earnings Sharing Mechanisms (ESM)

An earnings sharing mechanism (ESM) shares the surplus or deficit relative to a utility's allowed return on equity with customers. When a utility exceeds the prescribed ROE, customers and the utility share the excess earnings according to a prescribed formula. In some (symmetrical) ESM's, when a utility's earnings are below the allowed ROE, customers and the utility share the earnings deficit according to a prescribed formula. The ESM usually includes a deadband around the allowed ROE below or above which the sharing is triggered. The deadband is usually based on a pre-determined number of basis points above or below the authorized ROE, within which no sharing occurs.

Symmetrical ESMs are deigned to equitably share both the risks and benefits of PBR between shareholders and customers of the utility. Asymmetrical ESMs, which only share profits when the utility's ROE exceeds a specified deadband amount, share only the benefits of PBR with customers while allocating most of the risk to utility shareholders.

The inclusion or exclusion of an ESM generally has no impact on the determination of most other PBR elements (e.g., the inflation factor, the X factor, the Z factor), however they dampen the efficiency incentives because the utility does not retain all of the increased profits resulting from its efficiency gains.

Table 13 below sets out examples of the ESMs for several PBR plans.

Table 13: ESM in Recent PBR Decisions for Electric Utilities

Jurisdiction	Year	K Factor
Alberta	2023	Asymmetrical ESM with a deadband of 200 basis points above approved ROE Between 200 basis points and 400 basis points above the approved ROE utility retains 60% and customers receive 40% Above 400 basis points above the approved ROE utility retains 20% and customers receive 80%
Hawaii	2021	Symmetrical ESM with no sharing if ROE is between 300 basis points above and below approved ROE Up to 150 basis points outside the deadband in either direction customers and utility share gains or losses 50/50 Over 150 basis points outside the deadband, in either direction customers and utility share gains and losses 90/10
Massachusetts	2022	Asymmetrical ESM with a deadband of 200 basis points above the approved ROE Over 200 basis customers and utility share gains 75/25

XXVI. Re-openers / Off-ramps

A reopener as an element of a PBR plan provides an important safeguard. A re-opener addresses specific problems with the design or operation of a PBR plan that may arise or come to light as the term of the PBR plan unfolds, and which may have a material impact on either the company or its customers which cannot be addressed through other features of the plan. An advantage of a reopener is that it may allow the stay-out provision and the PBR plan to continue with modifications as necessary, without bringing the PBR plan to an end. In some cases, a PBR plan may include the provision for an off-ramp, which allows the utility to apply to terminate the plan altogether when its financial integrity is imperiled. An off ramp may also be triggered if a change of control is enacted as a result of a merger or acquisition that may require the plan to be terminated to facilitate the transaction.

In most cases, a re-opener or off-ramp is triggered when a utility's ROE exceeds or falls below a pre-determined number of basis points relative to the allowed ROE. The triggering event usually commences a review of the PBR plan automatically. In some cases, for example in Quebec and Ontario, the utility is required to file an application for a review within a set timeframe after utility's financial statements demonstrate that the triggering event has occurred. In Alberta the review is triggered only if an interested party, which may include a consumer advocate, files an application with the Commission.

In the ensuing regulatory proceeding, all parties may submit evidence and an opinion on potential adjustments to components of the PBR plan or to suggest termination of the plan altogether. The regulator then issues a decision directing modifications to the plan, continuation of the plan with no changes, or termination of the plan (an off-ramp). The decision may also require a refund of "over-earned amounts" to customers or a recovery of "under-earned amounts" to the utility.

Table 14 below sets out examples of the re-opener provisions for recent PBR plans.

Table 14: Re-Opener Provisions in Recent PBR Decisions for Electric Utilities

Jurisdiction	**Year**	**Re-opener**
Alberta	2023	Re-opener triggered on application from any interested party or on the Commission's own motion. Re-opener may be triggered when ROE exceeds allowed ROE by 300 basis points for 2 consecutive years or by 500 basis points in one year. With the adoption of an ESM in 2023, the reopener when ROE exceeds 300 basis points in two consecutive years was eliminated
Hawaii	2021	A Re-Opener investigation will be triggered if Hawai'i Electric's credit rating outlook indicates a potential credit downgrade below investment-grade status or if its ROE exceeds 450 basis points above or below the allowed ROE
Massachusetts	2022	No re-opener provision

In practice, re-openers are rarely triggered. Only three re-openers for an electric utility have been adjudicated, all in Alberta. ENMAX transmission's under-earning triggered a re-opener of its FBR plan.[52] The AUC initiated a proceeding to consider whether the FBR plan for transmission was flawed and required adjustment or the company under-performed, and the under-earning should be to the account of shareholders. The matter was resolved by way of a negotiated settlement that shared the recovery of the shortfall between consumers and ENMAX Transmission. In 2018, the AUC initiated a proceeding at the urging of consumer groups to re-open the plan for the *ATCO utilities. Decision 23604-D01-2019: AUC-Initiated Review Under the Reopener Provision of the 2013-2017 Performance-Based Regulation Plan for the ATCO Utilities, Proceeding 23604, February 27, 2019* determined that "there is no evidentiary basis to conclude that the earnings achieved by the ATCO Utilities above the Commission's generically approved ROE were the result of a problem with the design or operation of the ATCO Utilities' 2013-2017 PBR

[52] FBR was the acronym for the formula-based regulation plan approved in AUC Decision 2009-035 that approved an indexed price cap plans to ENMAX's distribution and transmission entities.

plans." More recently, also in Alberta, proceeding 28300, *AUC-Initiated Review under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Gas and ATCO Electric* is on-going.

XXVII. Performance Incentive Metrics (PIMs)

Performance incentive metrics provide a monetary reward to a utility for achieving specific outcomes.

These incentives are usually one of four types:

• **Share of net benefits:** Electric companies earn a percentage of the savings from their efficiency programs

• **Savings-based incentive:** Electric companies earn a reward for meeting a pre-established goal

• **Multifactor incentive:** Electric companies earn a reward for meeting a set of multiple pre-established savings-based goals

• **ROE:** Electric companies can include energy efficiency program spending in rates

Figure 3 below shows PIMS by state in the US.

Figure 3: PIMS by state as of 2019[53]

PIMS are not often included in PBR plans largely because the targeted outcomes are often indistinguishable from the overall public service obligations of the utility. Specifically, the Massachusetts

[53] Source: Guidehouse

Department of Public Utilities rejected the PIMs proposed by National Grid (electric) because, among other things, they were substantially encompassed within the utility's public service obligations.[54]

However, the Hawaii PBR plans include a significant number of PIMS designed to incentivize the utilities to accelerate the achievement of certain high priority public policy objectives, including Renewable Portfolio Standards and Distributed Energy Resource Asset Effectiveness, Customer Engagement, Interconnection Experience, Cost Control, Affordability, Grid Investment Efficiency, and GHG Reduction. As mentioned above, the numerous metrics monitored by the Hawaii PUC are largely related to PIMS.

XXVIII. Performance Metrics

Most regulated utilities in North America report performance metrics, whether they operate under PBR or COSR. Performance metric monitoring is usually required in a PBR plan to ensure that quality does not decline in favor of higher returns. However, there is little evidence in the academic literature of a relationship between PBR and reduced service quality, likely because a utility that is subject to regulatory scrutiny, regardless of the form of regulation, is loath to engage in practices that risk losing the regulator's trust.[55]

Typical metrics include customer service metrics, such as call center answer time and customer satisfaction measures. System average interruption duration indexes ("SAIDI") and system average interruption frequency indexes ("SAIFI") are almost universally monitored to provide a measure of the utility's reliability. Certain performance metrics may also be required to monitor the extent to which the utility is meeting public policy goals, such as connections to renewable generation. The Hawaii PBR Plan has 63 performance metrics, of which forty were enacted with the transition to PBR. In its most recent PBR decision, the Alberta Utilities Commission directed the utilities to report metrics as part of the annual review process designed to ostensibly monitor PBR efficiencies.[56]

Monitoring performance metrics comes with a cost that is ultimately borne by customers. Metrics must be designed to align with the capacity of the utility to report on the metric at a reasonable cost. The cost of monitoring a poorly designed metric may outweigh the benefit of the information provided. In most cases, it is unlikely that a PBR plan will benefit from the addition of metrics beyond those already in place prior to the implementation of the plan.

Table 15 below sets out an overview of the performance metrics for recent PBR plans.

[54] Massachusetts Department of Public Utilities, *Final Order,* Docket 18-150

[55] In the words of Joseph Hall, "A reputation once broken may possibly be repaired, but the world will always keep their eyes on the spot where the crack was."

[56] Decision 27388-D01-2023

Table 15: Performance Metrics in Recent PBR Decisions for Electric Utilities

Jurisdiction	Year	Performance Metrics
Alberta	2023	Performance metrics were carried over from COSR and two PBR specific metrics were adopted: controllable operations and maintenance (O&M) per customer total cost per customer, broken out by O&M and capital additions separately.
Hawaii	2021	Metrics are generally aligned with PIMS and include among others, metrics related to: Affordability Capital Formation Cost Control Grid Investment Efficiency Interconnection Experience Resilience DER Asset Effectiveness Customer Engagement Customer Equity SAIDI/SAIFI
Massachusetts	2022	Various service quality metrics and penalties plus additional performance metrics in three broad: (1) improvements to customer service/engagement (2) reductions in system peak (3) strategic planning for climate adaptation

XXIX. Efficiency Carry-Over Mechanisms (ECM)

An efficiency carry-over mechanism allows the utility to retain a portion of productivity gains achieved up to the end of the stay-out period for a period of time after the end of the PBR term. The purpose of the ECM is to avoid "gaming" by the utility in the last year of the stay-out period to enhance the base rates going into the subsequent PBR regime. The potential for this adverse incentive arises when rebasing between PBR generations appropriates the achieved productivity gains to the benefit of customers when a cost-based revenue requirement is established at the commencement of the next regulatory regime.

ECMs are uncommon in PBR plans in North America. The revenue cap plans currently in Massachusetts and Hawaii do not have defined ECMs. PBR plans in Alberta have included an earnings Carry Over

Mechanism (ECM) to strengthen incentives in the later years of the PBR term and to discourage "gaming" regarding the timing of capital projects. The ECMs allowed a company to carry over up to 0.5 percent of earnings above the allowed ROE achieved in the last year of the PBR term (stay-out period) in its revenue for the first two years of the subsequent PBR term.[57] In its most recent PBR plans, the Alberta Utilities Commission eliminated the ECM.

XXX. Annual Filing Requirements

Utilities operating under PBR submit annual filings. The primary purpose of an annual filing under PBR is for to set rates for the forthcoming year, including updates to I, Y, Z and ESM factors. However, the annual review may also include other requirements such as reporting on performance metrics. Annual filings are generally kept to a minimum to encourage regulatory efficiency and reduce regulatory burden for the regulator and the utilities.

XXXI. Revenue Decoupling and PBR plans

Policies and programs to promote energy efficiency such as conservation and demand side management usually result in decreased energy sales for utilities. Declining energy sales may lead to the utility's fixed costs not being fully recovered because traditional utility rate designs recover fixed costs primarily through volumetric charges. Without rates that recover most fixed costs through demand charges, a decrease in energy sales due to energy efficiency measures may result in earnings attrition for the utility. In these circumstances, utilities have little financial incentive to promote energy efficiency.

Revenue decoupling is intended to make utilities indifferent to declining energy sales resulting from efficiency measures by adjusting revenue to recover any shortfall related to energy efficiency initiatives up to the level of the revenue requirement approved by the regulator. In simple terms, decoupling periodically compares the authorized revenue and the actual revenue for the relevant period and then any revenue differential is recovered from, or credited to, customers in rates in the subsequent period.[58]

Decoupling mechanisms have been implemented in 33 U.S. states and the District of Columbia as of 2023.[59] However, with the advent of policies to encourage strategic electrification in many states, the need for revenue decoupling is beginning to be reconsidered. For example, the Massachusetts Department of Public Utilities recently determined that it must discontinue full revenue decoupling for electric distribution companies to ensure that they "embrace increasing clean electric load."[60]

To date, Massachusetts is the only jurisdiction with revenue decoupling in conjunction with PBR plans. Revenue capped PBR plans such as the plans in Massachusetts are compatible with revenue decoupling

[57] AUC Decision 2012-237

[58] The revenue differential may not be allocated equally to all rate classes.

[59] von Loessl, V. and Wetzel, H. (2022) 'Revenue decoupling, energy demand, and Energy Efficiency: Empirical evidence from the U.S. electricity sector', *Utilities Policy*, 79, p. 101416. doi:10.1016/j.jup.2022.101416.

[60] D.P.U. 21-120 through D.P.U. 21-129, pages 231-232

because the revenue differential is easily recovered from, or credited to, customers in rates, up to the level of the capped revenues. In addition, the ability to meet the revenue cap by reducing sales makes a revenue cap plan compatible with conservation, energy efficiency and demand side management policies. Although it is possible to design revenue decoupling mechanisms that are compatible with a price capped PBR plan, revenue decoupling is not generally adopted in conjunction with price capped plans.[61]

Because price capped PBR plans allow the utility to sell as much energy as possible at the prices dictated by the price cap, price capped PBR plans may be preferred in conjunction with strategic electrification policies because they facilitate further electrification and increased load. There is some debate, however, as to whether revenue decoupling may still be required in conjunction with strategic electrification policies if utility customers increasingly adopt self-supply and battery storage alternatives to grid supplied energy.[62]

XXXII. The Effect of PBR on Utility Performance

Assessing the success of any regulatory plan is difficult because quantitative analysis of their achievement is hampered by the absence of a counterfactual control group of companies under an alternative form of regulation experiencing the same conditions over the same period. There are, however, some statistically valid peer-reviewed academic studies of the results of PBR plans that have evaluated the effect of PBR on utility performance.

A study of the price impact of PBR plans in Canada by Crowley and Meitzen[63] compared rate increase outcomes among a control group of firms regulated under the traditional COSR method against rate outcomes under price caps in Alberta during the 2013-2018 period and in Ontario from 2005 to 2018. The study concluded that three Alberta distribution utilities increased rates at an average annual rate of 8.70% from 2004 to 2012 under COSR, while the same three utilities decreased rates at an average annual rate of 2.46% from 2013 to 2018 while under PBR. However, a more enlightening analysis in this study compared the effect of PBR on rates in Alberta under PBR to the performance of a counterfactual control group of utilities under COSR, revealing that:

> Since the Alberta Public Utility Commission enacted the price caps outlined in its 2012 Rate Regulation Initiative, distribution rates under that initiative have declined an

[61] The authors are not aware of any price capped PBR plans in conjunction with revenue decoupling.

[62] As utilities reinforce the grid to support the obligation to provide more grid-supplied energy in response to strategic electrification polices, the expected revenue from increased load may be offset by customer self-supply and storage alternatives. In this circumstance these countervailing forces may negatively affect utility earnings. A continuation of revenue decoupling may be warranted under such circumstances until utility costs, revenues and earnings stabilize to the point where decoupling is not longer needed.

[63] Crowley, Nick and Mark Meitzen. "Measuring the Price Impact of Price-Cap Regulation among Canadian Electricity Distribution Utilities." Utilities Policy, vol. 72, 2021, p. 101275., https://doi.org/10.1016/j.jup.2021.101275.

> average of 2.46 percent annually while utilities under ROR during the same period increased at an annual rate of 4.04 percent.[64]

This 6.51 percent differential was demonstrated to be statistically significant.

The same analysis for Ontario demonstrated that "during an average year in the study period, Ontario utilities increased rates 1.14 percentage points less than utilities under traditional ROR" with this difference being statistically significant when tested over the period 2014 through 2018.[65]

The study also cites numerous other analyses of PBR going back to 1998 that support the general conclusion that PBR is a superior form of regulation that constrains rate increases to the benefit of customers.

A more recent study by Lowry et. al[66] examined the effect of the indexed multi-year (PBR) rate plans in Alberta, concluding that:

> Our research on the productivity trends of Alberta power distributors supports the hypothesis that MRPs can materially slow utility cost growth by strengthening incentives. The O&M, capital, and multifactor productivity trends of ENMAX all materially exceeded the average trends of the other three distributors in the six years before PBR1.[67] During PBR1,[68] the O&M productivity growth of the other three distributors accelerated greatly while their capital productivity growth did not. In PBR2[69] the O&M productivity growth of these distributors was slower on average than during PBR1 but tended to be materially faster than in the years before PBR. The capital productivity growth of all four distributors tended to accelerate markedly during PBR2.[70]

The Alberta Utilities Commission undertook its own review of PBR in Alberta for the years 2013 to 2022.[71] The Commission reported that PBR has incented the Alberta utilities to find efficiencies in

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[64] Crowley, Nick and Mark Meitzen. "Measuring the Price Impact of Price-Cap Regulation among Canadian Electricity Distribution Utilities." Utilities Policy, vol. 72, 2021, p. 101275., page 6.

[65] Crowley, Nick and Mark Meitzen. "Measuring the Price Impact of Price-Cap Regulation among Canadian Electricity Distribution Utilities." Utilities Policy, vol. 72, 2021, p. 101275., page 7.

[66] Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta." *The Electricity Journal*, 3 July 2023, www.sciencedirect.com/science/article/pii/S1040619023000556.

[67] ENMAX was under a Formula Based Regulation plan governed by an (I-X) mechanism from 2009 to 2013.

[68] PBR1 refers to the PBR plan in effect from 2013 to 2017 discussed in Unitil-MK-1 at pages 27 to 33.

[69] PBR2 refers to the PBR plan in effect from 2018 to 2022 discussed in Exhibit Unitil-MK-1 at pages 33 to 37.

[70] Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta." The Electricity Journal, 3 July 2023, page 7.

[71] Decision 26356-D01-2021

service delivery;[72] that the companies were responding to the incentives of the PBR plans while maintaining service quality,[73] and that customers experienced lower rates under PBR than would be expected under COSR and some sharing of savings occurred during rebasing for the 2018-2022 PBR plans.[74]

Further evidence of the effect of PBR on utility performance is apparent in the recent benchmarking studies that demonstrate that the utilities under PBR have lower costs relative to peer companies under COSR. In proceeding DPU 23-80 before the Commonwealth of Massachusetts Department of Public Utilities, Exhibit Unitil-NAC-1, Appendix II shows that the two electric distribution companies currently operating under revenue caps, NSTAR Electric and National Grid (Massachusetts Electric Company) have performed favorably in terms of total cost growth over recent years. NSTAR Electric ranks first among Northeastern utilities, while National Grid ranks seventh out of 18 companies. Focusing strictly on O&M costs, both NSTAR Electric and National Grid have experienced lower O&M costs per customer than the national and Northeast samples during the PBR period between 2017 and 2021.

[72] Decision 26356-D01-2021 paragraphs 11 and 27.

[73] Decision 26356-D01-2021 paragraph 17.

[74] Decision 26356-D01-2021 (June 30, 2021) paragraph 79.

XXXIII. Reference Materials

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