Performance-Based Regulation: Basic Features and Possible Applications to Virginia's Electric Utilities

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Performance-based ratemaking ("PBR") and other alternatives to traditional cost of service ratemaking ("COSR") that are collectively called "Altreg" have evolved from concerns about how COSR performs under modern operating conditions. COSR entails rate cases that reset a utility's base rates periodically to reflect the prudently incurred cost of service. A rate of return can be earned on utility ownership of capital. Especially under challenging business conditions, rate cases are so held frequently such that regulatory cost is high, prudence reviews may be less thorough, and there is less time for utilities to profit from cost containment efforts before the benefits are passed to customers. Cost containment incentives weaken, and excessive capital expenditures ("capex") are a particular concern.

In recent decades, concerns about other dimensions of utility performance have further complicated ratemaking. Most notable is concern about the impact that energy utilities have on the environment. Another growing concern is the affordability of service to low-income customers.

Altreg options such as formula rates and expansive use of capital cost trackers can reduce regulatory cost. However, they do not strengthen and can even weaken utility incentives for cost containment and environmental stewardship.

Performance-Based Ratemaking

PBR approaches to Altreg strengthen utility incentives to perform well. Some approaches can also streamline ratemaking. Four well-established PBR approaches are discussed in this report.

- **Relaxation of the link between utility revenue and system use** can weaken the "throughput" incentive that discourages utilities from embracing demand-side management ("DSM") and distributed energy resources ("DERs"). Revenue decoupling is a popular means of accomplishing this relaxation in states that want to encourage DSM and DERs.
- **Metrics and performance incentive mechanisms ("PIMs")** can help ensure that performance in specific areas, that could be neglected, is tracked and encouraged. Reliability, customer service quality, and energy efficiency programs have been a popular focus of PIMs for some time. PIMs have recently been used to strengthen incentives for policy goals such as peak load management and the quality of service to DER customers.
- **Targeted incentives for underused practices** directly encourage practices that utilities tend to underuse because they discourage utility capex or reduce costs that are external to a utility's finances or subject to tracker treatment. A common example is tracker/rider treatment of DSM expenses. Tracker treatment has also been used in some states for utility costs of accommodating DERs and beneficial electrification. In addition to tracker treatment, targeted incentives for underused practices may also include management fees and pilot programs that encourage these practices.

- **A multiyear rate plan ("MRP")** entails a multiyear general rate review moratorium. Between rate reviews, the utility's revenue corresponding to many costs is escalated using an attrition relief mechanism that is not linked, like a cost tracker or formula rate, to the utility's actual cost during the plan. Predetermined revenue stairsteps, indexing, and hybrid approaches have been used to accomplish this. Ratemaking is streamlined, freeing resources in the regulatory community to address other issues. Cost containment incentives are strengthened. MRPs can be combined with integrated resource planning and the other three forms of PBR.

Application to Virginia

Cost Containment Incentives and Regulatory Cost

Under Virginia's current ratemaking system, the foreseeable future would involve frequent rate reviews, a sharing of earnings variances, and extensive use of cost trackers. We believe that this system entails unusually weak cost containment incentives. Moreover, the cost of routine rate adjustments is high at a time when Virginia faces many other complicated ratemaking issues such as rate designs, compensation for DER power surpluses, and integrated resource and delivery system planning. Multiyear rate plans may produce better results and are an option meriting careful consideration in Virginia's PBR study. However, MRPs must be designed carefully to ensure that customers share in plan benefits.

A full true up of the revenue requirement to a utility's cost is common at the start of an MRP. There are options for other plan provisions that make sense for vertically integrated electric utilities like those in Virginia. In the southeast U.S., MRPs are used to regulate vertically integrated electric utilities in North Carolina, Georgia, and Florida. An MRP was recently used in West Virginia for Appalachian Power.

MRPs have been the favored approach to ratemaking for utilities embracing the energy transition. For example, electric utilities in several states and countries that are leading the energy transition usually operate under MRPs including those in California, Hawaii, Massachusetts, New York, Australia, and Great Britain.

Revenue Decoupling

Revenue decoupling also merits serious consideration in the PBR study, as most of the reasons that decoupling is adopted in other jurisdictions exist in Virginia.

- Virginia's energy costs are projected to rise significantly in the coming years. Decoupling eliminates the utility's throughput incentive to increase energy sales, thereby reducing the incentive to oppose DSM and DERs.
- In an era of imminent capacity expansion, there is presently a great need for innovative rate designs that encourage peak load reductions. For example, decoupling can encourage pervasive use of time-sensitive rates by reducing the utility's risk of recovering some of the cost of base rate inputs in the peak-period charge.

Metrics and PIMs

Virginia's commission is currently considering standards and protocols on performance metrics and PIMs in another proceeding. Here is a brief summary of PEG's views on the matter.

- Virginia could benefit from the development of metrics and PIMs to measure and incentivize utility performance in targeted areas. The SCC has commendably developed a draft scorecard, metrics, and PIMs that reflect the comments of diverse parties. Finalization of metrics and PIMs is challenging and will take some time and effort. However, this effort should not sidetrack consideration of other PBR reforms as well.
- Our analysis suggests that a PIM is needed for DER customer service quality. A PIM for peak load management also merits consideration. PIMs for beneficial electrification are used in some jurisdictions where decoupling applies to these loads.
- Greater use of statistical benchmarking should be considered. Alternatives to simple unit cost and average rate metrics such as econometric cost modelling show promise and are used in several North American jurisdictions. Interutility benchmarking is also feasible for reliability metrics such as "blue sky" SAIDI and SAIFI.

Targeted Incentives for Underused Practices

Targeted incentives for underused practices are already employed in Virginia in the form of the tracking of DSM program costs. Thought should be paid to expanding the role of such incentives going forward. Management fees are a possible alternative to PIMs for encouraging peak load management, especially when the peak load containment is undertaken by third parties. Another area where targeted incentives for underused practices could be applied is the accommodation of DERs. Tracking costs of accommodating beneficial electrification also merits consideration if decoupling applies to these services.

Role of Cost Trackers

Cost trackers are a useful tool in electric utility ratemaking but should be used cautiously. Like measures to stimulate the economy during a recession, it is possible to use "too much of a good thing". We believe that too much of the Virginia utilities' capex is currently accorded tracker treatment. There is an art to limiting use of trackers chiefly to areas where cost is especially large and volatile, uncertain, or the use of the associated inputs merits encouragement.

1. Introduction

In 2024, the Virginia General Assembly approved House Joint Resolution 30 and Senate Joint Resolution 47, directing Virginia's State Corporation Commission ("SCC" or "the Commission"), in collaboration with the Department of Energy ("Virginia Energy"), to study the potential of performance-based ratemaking ("PBR") and other alternatives to traditional ratemaking to modernize regulation of the Commonwealth's investor-owned electric utilities.[1] The SCC is directed to "propose reforms to the current regulatory framework" in a report to regulators that is due next fall. Virginia Energy has been tasked with managing a stakeholder process that will inform the SCC study.

The resolution states that modernization may encompass.

- tracking and achieving improved performance in affordability, reliability, customer service, and resiliency;
- enhancing cost-containment incentives;
- streamlining planning and resource procurement to secure competitive prices for energy infrastructure;
- harmonizing financial incentives created through ratemaking with the Commonwealth's energy policy goals;
- eliminating disincentives for utilities to deploy third-party and customer-owned generation, energy efficiency savings, and peak-load reduction; and
- making progress toward the Commonwealth's decarbonization goals.

Specific PBR tools that the SCC study must address include but are not limited to multiyear rate plans, revenue decoupling, fossil fuel cost sharing mechanisms, and performance incentive mechanisms, scorecards and metrics. The resolution requires the Commission to consider a range of performance areas in its study of PBR and alternative regulatory tools, including reliability and resiliency; affordability for customers; emergency response and safety; cost-efficient utility investments and operations; customer service; savings maximization from energy efficiency and exceedance of statutorily required savings levels; peak-demand reductions; integration of distributed energy resources, including the quality and timeliness of interconnection of customer-owned and third-party-owned resources; environmental justice and equity; beneficial electrification, including in the transportation and buildings sectors; maximization of available federal funding; and decarbonization of the Commonwealth's electricity sector.

Pacific Economics Group Research LLC ("PEG") has for decades been a leading North American consultancy on PBR. Our personnel have been active in the field since the late 1980s. Our work for a mix of regulators, government agencies, consumer and environmental groups, utilities, and trade associations has given our practice a reputation for objectivity and dedication to good regulation. Clean Virginia has retained PEG to prepare an independent report on PBR and its possible application to

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[1] Virginia House of Delegates, 2024. House Joint Resolution No. 30.

Virginia's investor-owned electric utilities. This report will help inform Virginia Energy's PBR stakeholder process.

Our report begins with a brief overview of utility regulation and tools that are available to regulators, followed by a discussion of the traditional cost of service approach to ratemaking and its suitability for addressing modern business conditions. We then consider salient alternative approaches to ratemaking that include PBR approaches. The report concludes with a review of Virginia's current regulatory system and some preliminary comments on possible PBR reforms. Appendix 1 provides a glossary of terms that are used in the paper, while Appendix 2 provides brief summaries of the attrition relief mechanisms and other provisions of the MRPs of several utilities, and Appendix 3 discusses our credentials.

2. An Introduction to Electric Utility Regulation

An electric utility is an enterprise empowered by a government to provide electric services such as generation, transmission, and distribution in markets with restricted competition. This set-up enables the utility to realize economies of scale and avoids market tumult in the provision of essential services. In return for this opportunity, the utility must submit to extensive government regulation of its operations. Regulation can help protect customers from the abuse of market power and ensure that the utility is reasonably remunerated for its operations. This arrangement between government and the utility is called the regulatory compact.

Various tools are available to regulate electric utilities. These can be usefully grouped into three broad categories:

- Structural Approaches
- Command and Control Approaches
- Rate and Service Regulation

2.1 Structural Approaches

Policymakers influence power industry performance through their decisions concerning the structure of markets that utilities might serve. Utilities may be granted a service monopoly to some markets, but in other markets, competition may be permitted along with utility service, or utility participation may be discouraged or prohibited. For example, utilities may be compelled to buy all of their power from suppliers rather than generating it themselves, or to refrain from offering behind-the-meter heating, ventilation, and space heating services that compete with local businesses. Utilities may be required to outsource some of their functions and/or to use competitive bidding to obtain some inputs.

2.2 Command and Control Approaches

Policymakers have many opportunities to mandate what utilities do. For example, they may choose to impose a renewable portfolio standard ("RPS") and/or an energy efficiency resource standard ("EERS").

2.3 Rate and Service Regulation

Public utility commissions are typically charged with regulating the terms on which utility services are offered. Commissions may rule on the services offered as well as on the rates the utilities charge their customers. Commissions should aim to ensure that utilities operate efficiently and reliably, charging rates that are fair for the services that customers want.

Competitive Market Paradigm

Good utility regulation is sometimes characterized as simulating the outcomes of well-functioning competitive markets.[2] Prices of products in such markets reflect the costs of typical firms, not those of individual suppliers. Prices in these markets are sensitive to product quality. For a competitive market to be well functioning, suppliers would also ideally pay for most of the collateral costs of their operations and be compensated for collateral benefits, so that there are few externalities.

Suppliers in competitive markets are incentivized to contain their costs. These suppliers do not generally favor capital cost over operation and maintenance ("O&M") expenses. In a competitive market, replacement of older or poorly performing assets is motivated chiefly by a desire to preserve service quality and avoid rising O&M expenses. Major tasks in the supply chain may be outsourced, including many that are capital-intensive.

Competition between suppliers passes most of the benefits of industry performance gains to customers in the long run. Superior returns may be earned by good performers, while inferior returns may be earned by bad performers.

Cost of Regulation

In choosing an approach to ratemaking, cost to regulators is an important consideration. Regulatory cost matters more to the extent that

- funds for ratemaking are limited;
- the size of the utility industry is large;
- the commission must regulate numerous utilities; and
- there are many complicated generic issues such as rate designs to consider.

[2] See, for example, New York Public Service Commission, "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework," Order issued May 19, 2016 in New York Public Service Commission Case 14-M-0101, p. 64.

3. Traditional Utility Ratemaking and Notable Alternatives

In this section of the report, we consider the traditional North American cost of service ratemaking ("COSR") and some notable alternative forms of ratemaking ("Altreg") that are used today. We first discuss the way that utilities are compensated for their services under COSR. Next, we provide a critique of COSR that questions its ability to produce good results under modern business conditions. We then introduce Altreg options that include PBR.

3.1 COSR

Under traditional ratemaking[3], regulated rates for utility services (also called tariffs) are determined using a process that has the following features.

- A base revenue requirement is established in occasional rate cases. This revenue requirement should reflect the costs that the utility has recently, is currently, or is expected to soon incur for capital, labor, materials, and services. Costs are usually subject to prudence reviews that may result in disallowances.
- This revenue requirement is allocated between tariffed services. Base rates are then designed for each service that are expected to recover the costs allocated to it.
- Utilities are typically free to file rate cases as needed to obtain relief from financial attrition.
- On top of the rates approved during rate cases, the costs of energy commodities that the utility purchases are typically "tracked" by balancing accounts and are eligible for quick recovery from ratepayers through surcharges (also called riders) approved via expedited commission review. These are typically "two-way" trackers, where any money resulting from the utility spending less than predicted is returned to customers, and any deficit resulting from the utility spending more than predicted may be recoverable from customers.
- Rate designs are expressly approved by the utility commission and may reflect a wide range of considerations that include cost causation, affordability, and appropriate price signals to inform customer usage decisions. U.S. regulators have traditionally favored rate designs with usage [e.g., volumetric (per kilowatt hour) or demand (per kilowatt)] charges that recover both a sizable share of the utility costs that are fixed in the short run and the costs of energy commodities, which are inherently variable.

3.2 Critique

Traditional COSR developed in the early and middle 20th century to organize and regulate the service provided by the first public utilities. At the time and in ensuing years, COSR fulfilled several functions of utility regulation. The monopoly status of the utility permitted economies of scale. Under

[3] The section discusses traditional ratemaking and not the approach to ratemaking that is currently used in Virginia.

this system, the regulator limits utility earnings to a risk-adjusted rate of return and contains utility operating risk. This allowed for a rapid expansion of capital assets necessary to develop the early stages of the electricity industry in America. However, as systems grew in complexity and a wider set of technologies and multiple business models in the electricity sector became available, traditional COSR is not as well equipped to respond to the needs and technological possibilities of the energy sector.

The classic critique of COSR puts heavy weight on the asymmetry of information between the utility and other members of the regulatory community.[4] It is challenging even for the managers of a utility to understand whether its operations are efficient and how they can be made more efficient. The rest of the regulatory community generally has far less of an understanding. Additionally, utility efforts to influence decisions of regulators regarding rates tend to be better financed than those of other parties, giving them an advantage over other stakeholders in ratemaking proceedings. It is challenging under these circumstances to determine with certainty that a utility proposal should be rejected. Further, competent oversight of utility operations is costly.

Faced with limited budgets, regulators understandably try to contain the cost of ratemaking on their way to producing reasonable decisions. Some of these measures have adverse consequences. For example, regulators may choose to limit the scope and thoroughness of their prudence reviews, which often has the result of limiting the size of any prudence disallowances. This weakens the utility's cost containment incentives.

Another common measure regulators take to contain the cost of ratemaking is to give tracker treatment to more costs. In states where rate cases do not operate on a set schedule, this can reduce the frequency of general rate cases, thereby reducing regulatory cost and helping to preserve utility incentives to contain costs that are not tracked. However, giving tracker treatment to more costs weakens incentives to contain tracked costs because utilities have little or no opportunity to profit from efforts to cut these costs.

Tracker treatment of energy utilities' principal variable costs (i.e., the costs of fuel and purchased power) weakens these utilities' incentive to discourage uneconomic load growth. High volumetric charges further weaken this incentive since, when there is excess capacity, load growth bolsters margins between rate cases. In the longer run, load growth also creates opportunities for load-related capital expenditures ("capex"), which offer utilities a chance to increase earnings. These circumstances give rise to what is sometimes called the "throughput" incentive, meaning the strong

[4] The issue of information asymmetry and COSR has been discussed in many papers. This concern is commonly intertwined with concerns about cost containment incentives. An early article that discussed some implications of information asymmetry was Averch, H., and Johnson, L., 1962. "Behavior of the Firm under Regulatory Constraint," American Economic Review, Vol 52, No. 5, December. A book chapter looked at some specific case studies of information asymmetry and rate reviews. See Fremeth, A., and Holburn G., 2009, "Information Asymmetries and Regulatory Rate-making: Case Study Evidence from Commonwealth Edison and Duke Energy," published in *Regulation, Deregulation, and Reregulation: International Perspectives*. eds. Claude Menard and Michel Ghertman, Northampton, MA: Edward Elgar Publishing: 289-326. A more recent article that discussed the issue in the context of fuel procurement is Cicala, S., 2014. "When Does Regulation Distort Costs? Lessons from Fuel Procurement in U.S. Electricity Generation," National Bureau of Economic Research Working Paper 20109, https://www.nber.org/papers/w20109.

incentive that energy utilities have under COSR to boost load growth and resist demand-side management ("DSM") and distributed energy resources ("DERs") that reduce load growth.

In addition to limiting the scope and thoroughness of prudence reviews and increasing the use of riders, a third common tactic regulators use to contain their costs is to limit utility operating flexibility when it is difficult to assess the prudence of actions utilities might take with more flexibility. For example, regulators may choose to significantly restrict rate and service offerings. This in turn means utilities must often work with a restricted set of tools to address their challenges.

Impact of External Business Conditions

In a white paper for Lawrence Berkeley National Laboratory, we presented the further argument that the efficacy of traditional ratemaking varies with the business conditions that utilities face.[5] These conditions include input price inflation and the opportunity to bolster margins from increased capacity utilization. To the extent that key business conditions are favorable (e.g., input price inflation is slow), revenue growth between rate cases roughly matches or even exceeds utility cost growth. Rate cases are then infrequent, which strengthens utility cost containment incentives by affording utilities more time to profit from efficiency improvements. Customers receive the benefit of base rates that are unchanged in nominal terms and falling in real terms. Regulatory cost is low.

On the other hand, when business conditions are chronically challenging (e.g., inflation is rapid), the cost of utility operations tends to grow faster than utility revenue. Utilities then file rate cases more frequently, which weakens their cost containment incentives. Cost containment incentives tend to be weak just when base rates are rising rapidly.

Frequent rate cases also raise regulatory cost. We noted in Section 2.3 that regulatory cost also depends on the number of utilities in a regulator's jurisdiction, the scale of utility operation (e.g., 100 vs. 10 substations), and the extent to which regulation involves complex and controversial issues.

Frequent rate cases can also cause the scope and thoroughness of prudence reviews to be further contained. This further weakens cost containment incentives that are already weak when rate cases are frequent.[6] Regulators may also be more inclined to limit utility operating flexibility when the prudence of actions utilities might take with more flexibility is difficult to assess.

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[5] Lowry, M.N., Makos, M., Deason, J., and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

[6] Alberta's regulator noted the following in a letter initiating a PBR proceeding after years of considering biennial rate cases:

> "This initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources… Regulators … must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second

Overinvestment Concerns

Overinvestment in capital is a particular concern when utility cost containment incentives are weak. To understand why, consider that if a utility's revenue equaled its cost exactly (a hypothetical situation that is sometimes called "cost-plus" ratemaking), capex would be the only way for the utility to bolster earnings. If, alternatively, utility rates were reset to reflect their costs every ten years, it could be profitable to contain capex by means that could include increased uses of O&M expenses. For example, increased DSM could forestall the need for a capacity expansion and the utility could profit from the cost savings rather than passing them through immediately to customers.

Telltale signs of utility overinvestment include premature replacement of aging assets; premature and excessive expansion of system capacity; and excessively remote placement of generation assets to increase transmission opportunities. Weak cost containment incentives also encourage utilities to favor capex over other solutions to operating challenges. Decision points where capex/opex bias can arise include the following:

- capacity expansions vs. DSM and DERs to meet demand growth and achieve clean energy goals.
- self-generation vs. power purchases; and
- network undergrounding vs. vegetation management as a means of dealing with high levels of service territory forestation.

Environmental Stewardship

It is also noteworthy that most electricity consumed in North America is generated using fossil fuels, the production and consumption of which harms the environment. The incentive utilities have to contain environmental damage from generation and other operations is a complex issue. Reasons for concern include the following:

- Environmental damage from utility operations is an externality in the sense that the damage chiefly occurs to other parties and these parties have difficulty obtaining compensation.
- We have noted that typical utility rate designs provide "a throughput incentive" to boost margins between rate cases.
- Load growth can also increase opportunities to invest in capacity expansions.
- The costs of fossil fuels and purchased power made from them are generally afforded tracker treatment that reduces the financial incentive to contain them.
- U.S. utilities do not pay carbon taxes, and even if they did, these fees would also likely receive tracker treatment and be passed through to customers.

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guessing…The Commission is seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected."

Alberta Utilities Commission, "AUC letter of February 26, 2010," pages 1-2, Exhibit 1.01 in Proceeding 566.

- The costs of some fossil-fueled generating capacity and associated transmission facilities could be stranded. For example, the utility might not be compensated for the depreciated rate base of a prematurely retired power plant. This incentivizes the utility to keep the plant used and useful.

The following considerations suggest that, nonetheless, the COSR system could still provide utilities some incentives to play a constructive role in the energy transition.

- Technologies for generating power from clean energy resources are highly capital intensive.
- Low-cost opportunities to generate power from renewable resources are often remote from load centers and require transmission capacity to deliver them.
- Beneficial electrification will likely require capacity expansions.
- A reliable, resilient, and smart grid is needed if the power industry is to increase reliance on intermittent renewable resources and supplant fossil fuels in major sectors of the economy. The development of such a grid will require capex.
- Utilities can access capital markets at lower rates than customers or third parties for required energy transition capex.

Utility operations may also produce positive externalities. For example, low-carbon electrification of transportation and space heating can benefit the environment. The local community may benefit from the placement and retention of a large industrial load or from forms of generation that rely more on labor and other local inputs. When utilities are not able to share in these extra benefits of their actions, they have little incentive to create these benefits.

3.3 How Business Conditions Have Changed

Our analysis raises the question of how key business conditions that affect a utility's finances have changed over time. Salient business conditions include inflation in prices of base rate inputs, the need for utility capex, the extent to which capex is self-financing, and the extent of opportunities to increase capacity utilization due to load growth and excess capacity. The last of these conditions warrants additional explanation.

Growth in system use sometimes spurs costly capacity expansions, but also boosts utilization of existing capacity and can permit the realization of scale economies. When, additionally, rate designs have high usage charges, brisk growth in system use causes revenue to grow more rapidly than costs if there is excess capacity. The cost of gas and electric utilities is highly correlated with the number of customers they serve. Thus, use per customer (also called average use) is an indicator of the tendency of revenue growth to outpace cost growth.

Research by PEG has shown that the business conditions facing electric utilities were generally favorable before the late 1960s. Inflation was generally slow except in times of war. Average use of power by residential and commercial ("R&C") customers grew briskly. Economies of scale could be realized from system expansion. Capex was mostly growth-related and was therefore to a considerable degree self-financing. These conditions reduced the need for frequent rate cases. Cost containment incentives were relatively strong and regulatory cost was relatively low. We have called this the "golden age" of COSR, when it became a well-established tradition in utility ratemaking.

The energy price shocks of the 1970s and early 1980s triggered hyperinflation that accelerated utility input price growth. Growth in R&C average use slowed markedly. Rate cases were much more frequent, weakening utility performance incentives. During these years, many utilities made purchased power commitments and investments in costly generation capacity that greatly exceeded market needs. Disparities between the regulated and market price of power that resulted under these circumstances led eventually in many states to a required sale or spinoff of utility generation. In these states, utilities have survived as "wirecos" providing transmission and distribution services.

Inflation slowed in subsequent years, and some of the surviving vertically-integrated electric utilities ("VIEUs") were able to grow into the excess generation and transmission capacity that they had built. However, growth in R&C average use did not rebound to the pre-1970s pace, so margins from increased capacity utilization were smaller. Larger utilities may have exhausted their opportunity to realize incremental scale economies.

In recent years, the biggest development affecting the industry has been mounting concern about its effect on climate change. This has spurred governments to encourage more DSM and DERs, cleaner power generation, and beneficial electrification in the form of clean-electricity solutions for the economy's fossil-fueled activities. Other notable developments have included the aging of the grid and advances in technologies for power generation and distribution and customer service.

Electric utility cost has tended to grow briskly for various reasons. VIEUs and wirecos alike may need sustained high capex to build transmission capacity to connect to remote sites of clean generation, replace aging facilities, handle DER power surpluses, and/or improve system reliability and resiliency. Technological change has created opportunities for advanced metering infrastructure ("AMI") and other "smart grid" capex that improves utility performance (e.g., accommodation of intermittent renewables).[7]

On the revenue side, many of the drivers of cost just mentioned do not trigger automatic revenue growth like the buildout of the grid before 1970 had. Growth in the average use of R&C customers is still sluggish in many parts of the country, slowed by DSM programs and, in some areas, by growth of DERs that are served under net energy metering arrangements. On the other hand, growth in system use has been boosted in some areas by warmer weather, beneficial electrification, and data centers. The net effects of these demand drivers vary by region. Where data center growth is especially rapid, it often prompts generation capacity additions.

The bottom line is that cost growth of many utilities tends to exceed their revenue growth. The result is chronic financial attrition between rate cases that, under traditional ratemaking, would be remedied by more frequent rate cases. These frequent rate cases shrink utility's incentives to control

[7] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

costs. Demand growth is accelerating in some areas but this will sooner or later require capacity expansions that reduce the salutary effect on utility finances.

Regulatory resources that are currently devoted to electric rate cases have many alternative uses in this era of rapid change. For example, many regulators lack experience with grid modernization proposals. They want to make sure that plans for capacity expansion take proper account of DSM and DER options. Regulators are also concerned about how to regulate new products and services that a smarter grid makes possible. DSM programs and new services can be offered by third parties as well as utilities. Other issues raised by modern operating conditions include rate designs, compensation to DER customers for their power surpluses, "smart grid" investments, integrated resource and delivery system planning, the cost-effective glide path to increased renewables reliance, and coordination with other state agencies in matters such as environmental, land use, and zoning issues.

3.4 Altreg Options

Capex Trackers and Formula Rates

Some business conditions have stimulated development of alternatives to traditional ratemaking --- collectively called "Altreg" --- over the years. Most commonly, additional costs are tracked that would otherwise increase the frequency of rate cases. These may include additional costs that are large and volatile (e.g., pension and severe storm expenses) and/or costs that are rapidly rising.

Costs of capex have been the biggest focus of expanded tracking. Capex trackers typically recover the annual costs of capital projects. These include depreciation, return on rate base, and taxes. Expanded use of trackers usually does not require legislative authorization or sweeping change in ratemaking practices.

In the extreme, regulators have agreed to cost of service formula rates that are essentially comprehensive cost trackers.[8] In the United States, the Federal Energy Regulatory Commission ("FERC"), faced with numerous jurisdictional utilities, the need of many utilities for high capital expenditures, and complex regulatory issues, has opted for formula rates to regulate many power transmission utilities. Formula rates are used to regulate retail services of energy utilities in several southeastern states.

When the regulatory community is considering PBR options, the most likely alternative that might instead be chosen today may then, for better or worse, be formula rates or expanded use of capital cost trackers rather than traditional COSR. Expanded use of tracking can reduce rate case frequency, thereby reducing regulatory cost and helping to preserve utility incentives to contain costs that are *not* tracked. However, incentives to contain tracked costs are weakened.

To guard against this problem, regulators can subject tracked costs to especially thorough prudence reviews or design trackers to be more incentivized. One way to incentivize trackers is to share

[8] This is most commonly done for electric utilities in Mississippi and states bordering it as well as those states where Exelon subsidiaries operate.

variances. "One-way" trackers return underspends to customers but do not permit recovery of overspends.

As the eligibility for tracker treatment expands, regulatory cost falls but cost containment concerns widen. Studies by PEG and other consultants have shown, for example, that the multifactor productivity growth of the U.S. power transmission industry, where formula rates are extensively used by FERC, has been negative for many years. Opposition to formula rates from regulators is often so strong that they must be compelled to use them by legislation.

Additional concerns with capex tracking include the fact that the prudence of capex proposals or actuals is often hard for regulators and intervenors to assess. A common problem is the lack of evidentiary support by the utility. Note also that utilities do not usually promise less frequent rate cases in return for trackers even though this is a potential benefit.

PBR Alternatives

PBR encompasses other kinds of Altreg that strengthen utility incentives to perform well. Most PBR approaches used today can be characterized as incremental reforms to COSR designed to address these problems, rather than entirely different regulatory systems. For example,

- Multiyear rate plans strengthen the incentive to contain the cost of base rate inputs by reducing the frequency of rate cases.
- Revenue decoupling reduces the throughput incentive to bolster system use.
- Other PBR provisions provide targeted encouragement for underused inputs and practices.
- Performance incentive mechanisms target weak points in a utility's incentive structure using targets and metrics.

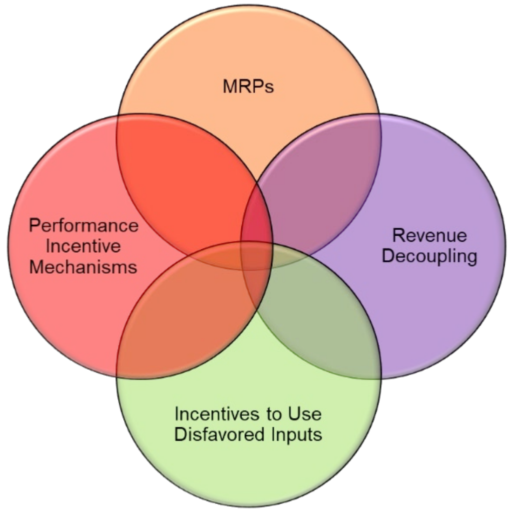
The various approaches to PBR can be and frequently are combined, as Figure 1 below illustrates. One reason for these combinations is that the individual tools may not satisfactorily address all incentive problems. Another is that some tools can produce undesirable side effects that other PBR tools can counteract. In Sections 4-7 of this report, we discuss each of the major PBR approaches and the ways that they interact in some detail.

The stronger incentives provided by PBR can result in improved utility operating efficiency. Some PBR approaches have other benefits that have encouraged their use. For example, multiyear rate plans ("MRPs") can streamline regulation and facilitate greater utility operating flexibility. Revenue decoupling can address some attrition problems and thereby reduce rate case frequency.

Regulators concerned about utility performance also have recourse to other correctives. These include heightened prudence reviews and newer approaches to oversight such as integrated resource and delivery system planning. These approaches can be used simultaneously with PBR.

Figure 1

PBR Approaches are Frequently Combined



4. Relaxing the Revenue/Usage Link

Many regulators want to relax the link between a utility's base revenue and the kWh and kW of system use by customers. This is a form of PBR because it reduces the throughput incentive that utilities have to boost the utilization of their systems. This can be desirable under various circumstances that include the following:

- Costly capacity additions are imminent because of demand growth or the need to replace fossil-fueled capacity.
- The utility has weak incentives to contain growth-related costs due, for example, to energy and capital cost trackers or formula rates.
- Growth in system use entails substantial negative externalities due, for example, to power generation pollutants.

Two methods are widely used in North America for relaxing the revenue usage link: revenue decoupling and lost revenue adjustment mechanisms ("LRAMs"). We discuss these options in turn.

4.1 Revenue Decoupling

Revenue decoupling adjusts a utility's rates mechanistically to help its *actual* revenue track its *allowed* revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism. The RDM tracks variances between actual and allowed revenue and adjusts rates periodically to reduce them. A rate rider is commonly used to draw down these variances by raising or lowering rates.

The revenue adjustment mechanism escalates allowed base rate revenue to provide relief for cost pressures between rate cases. The great majority of decoupling systems have such a mechanism since, if the RDM makes allowed revenue static, the utility will experience financial attrition as its costs rise. Costs of utility base rate inputs typically rise because input prices typically rise and the scale of its operations typically grows. When utilities do not have multiyear rate plans, revenue adjustment mechanisms approved in the United States typically escalate allowed revenue only for customer growth.

The potential benefits of revenue decoupling are numerous. It eliminates the throughput disincentive for a wide array of utility initiatives to encourage DSM and DERs, without relying on complicated load impact calculations or rate designs with high fixed charges that could discourage customers from adopting efficient DSM and DERs.[9] Decoupling also encourages innovative rate designs. For example, decoupling reduces the risk from offering customers time-sensitive usage charges that recover costs of base rate inputs in peak period charges. Decoupling can also compensate utilities for reduced usage-charge revenue due to DSM promotion by third parties, such as government agencies. Rate cases are less frequent to the extent that utilities are experiencing declining average use. Decoupling also reduces controversy over billing determinants in rate cases with future test years.

On the downside, decoupling may produce unwelcome revenue bumps during recessions. Decoupling may also be undesirable for some services. For example, some customers may have a demand for utility services that is particularly sensitive to the terms of service. Utilities under decoupling may in such cases be insufficiently attentive to retaining the business of these customers. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue and are often the primary focus of DSM programs.[10]

Electric vehicles can produce positive environmental impacts and permit reductions in rates to other customer classes. In North Carolina, electric utilities have revenue decoupling for residential customers and are permitted to exempt revenues from electric vehicle rates. In jurisdictions where beneficial electrification is subject to decoupling, it can be encouraged by other PBR tools. The Massachusetts commission recently considered terminating decoupling because of beneficial electrification concerns but instead decided that "For the Commonwealth to meet its GHG reduction targets, both energy efficiency and strategic electrification will be necessary and thus decoupling in some form will continue to play a prominent role."[11]

States that have recently used revenue decoupling for electric and gas utilities are indicated on the maps below in Figures 2a and 2b, respectively.[12] In the electric utility industry, it can be seen that decoupling is currently used in 18 jurisdictions. DSM and DERs are encouraged by policymakers in many of these jurisdictions. Decoupling is more common in the gas distributor industry and is the most

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[9] Load impact calculations may nonetheless be undertaken to help ascertain the effectiveness of DSM programs.

[10] In a multiyear rate plan, service classes excluded from decoupling can be subject to price caps.

[11] Massachusetts Department of Public Utilities, D.P.U. 23-80, Final Order, June 28, 2024, p. 418.

[12] The maps reflect the status of decoupling circa October 2024.

Figure 2a

Current Electric Revenue Decoupling Precedents in American States

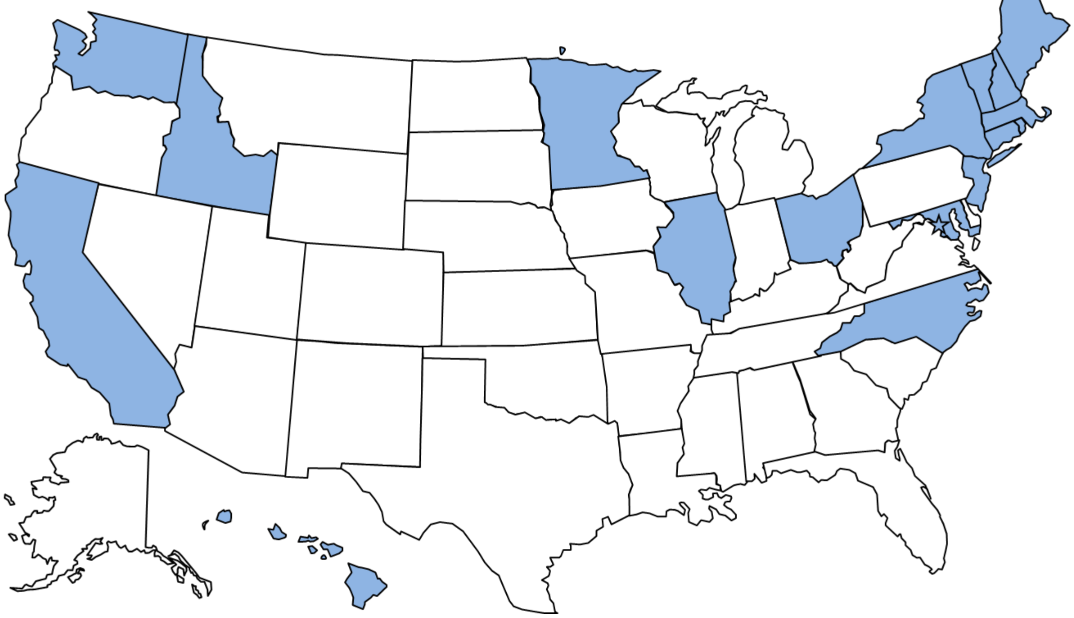
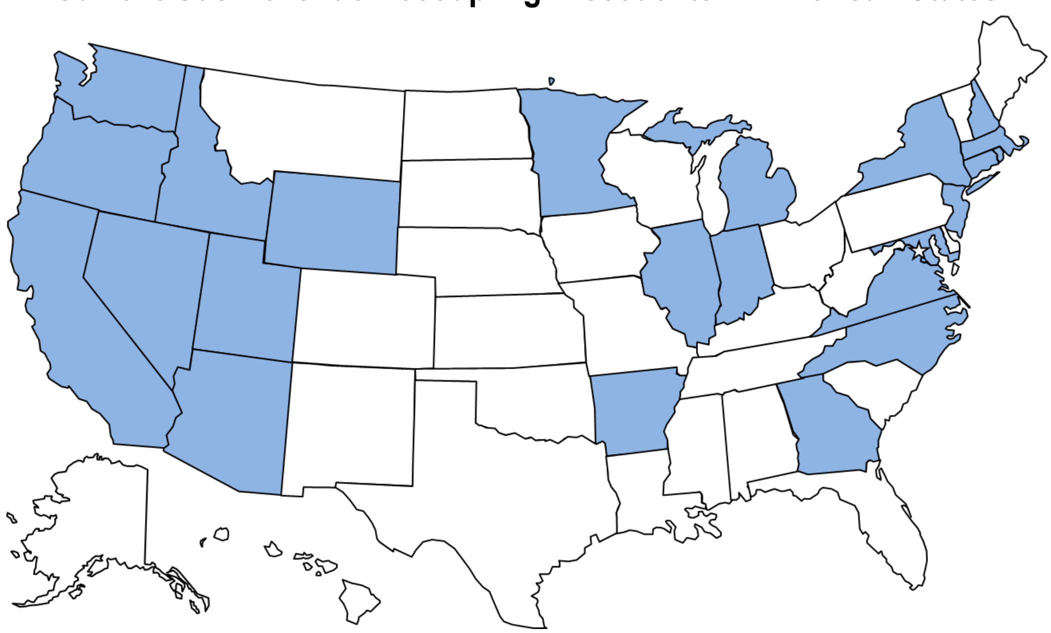


Figure 2b

Current Gas Revenue Decoupling Precedents in American States



widespread means of relaxing the revenue/usage link there. This reflects the fact that gas distributors often experience declining average use and that this has been due chiefly to external forces.

4.2 LRAMs

A lost revenue adjustment mechanism ("LRAM") is a tool that explicitly compensates utilities for short-term losses in base rate revenues that they experience due to their DSM programs, and possibly DERs. Estimates of load losses are needed to calculate the compensation. The lost revenue is usually collected through a special rate rider.

LRAMs reduce the disincentive for utilities to embrace DSM and DERs. By reducing earnings erosion, they may also reduce the required frequency of rate cases. On the other hand, LRAMs generally do not compensate utilities for the effects of important external forces, like the DSM initiatives of public agencies, which slow load growth. Moreover, estimates of load savings from utility DSM can be complex and are sometimes controversial. The scope of DSM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. If the utility has high usage charges, it remains at risk for revenue fluctuations, due to variation in volumes and peak load, which may result from changes in weather, local economic activity, and other volatile drivers of system use.

5. Performance Metric Systems

5.1 The Basic Idea

Performance metrics quantify aspects of utility operations that matter to customers and the public. The use of metrics in regulation can alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and reduce the cost of oversight on balance. "Scorecards" summarizing results for key metrics are often tabulated and may be posted on a publicly available website or included in customer mailings.

Metrics that are closely linked to the welfare of customers and the public include those that address the cost of service and service quality. A familiar example of such metrics is the system average interruption frequency index ("SAIFI"), which measures an aspect of service reliability. There is also an interest in "intermediate" metrics that are closely associated with variables of ultimate interest. An example is the number of customers taking service with time-sensitive rates.

Target values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics with the targets. This is typically done by taking the differences or ratios between the actual and target values. Performance appraisals can focus on the *level* of a metric or on its *trend*.

Quantitative performance appraisals using metrics are sometimes used in ratemaking. A performance incentive mechanism ("PIM") can, for example, link revenue mechanistically to the outcomes of performance appraisals based on metrics. These revenue adjustments can be made in rate cases and/or between rate cases. The following simple mechanism for a hypothetical utility called Eastern Power is one example of how a PIM can be designed:

$$\textit{Revenue Adjustment}^{Eastern} = \$ \ x \ (\textit{SAIFI}^{Eastern} - \textit{SAIFI}^{Target})$$

Here, SAIFI is the performance metric. The SAIFI value attained by Eastern is compared with a target. The term "$" is the award/penalty rate per unit of deviation from the target. If Eastern meets the target, then $SAIFI^{Eastern}$ equals $SAIFI^{Target}$ and the revenue adjustment is zero. If Eastern performs better than the benchmark, the company may increase its revenue. By the same token, if Eastern underperforms, it must decrease its revenue.

Targets that provide a realistic stretch goal for the utility and properly reflect circumstances that it cannot control can be difficult to establish. For example, the SAIFI of a utility depends on the extent of system undergrounding, forestation, and the prevalence of severe storms. Improved reliability can be costly. The full set of business conditions that "drive" a metric and their relative importance is often unclear.

Consideration of conditions that influence the *level* of a metric can be sidestepped by making the *trend* in its value the focus of the performance appraisal. A PIM could, for example, focus on the change in a utility's SAIFI from its recent average historical value, and not address whether historical reliability was appropriate. A focus on trends is thus especially convenient when there is not much reason for the target to change over time.

5.2 Popular PIMs

Service Quality

Service quality is one of the most common areas of utility operations where metrics are employed in utility regulation. Service quality PIMs can strengthen incentives to maintain or improve quality and simulate the connection between revenue and product quality that firms in competitive markets experience. Service quality PIMs for electric utilities have traditionally fallen into two general categories: reliability and customer service.[13]

Reliability

Performance metric systems commonly feature metrics for systemwide outage frequency and duration and may also feature regional or local reliability metrics. System reliability metrics are most likely to provide the basis for PIMs. The most common system reliability metrics used in PIMs are SAIFI and the system average interruption duration index ("SAIDI"). Another reliability metric commonly used in PIMs is the customer average interruption duration index ("CAIDI").

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[13] See Kaufmann, L., Getachew, L., Rich, J., and Makos, M., *System Reliability Regulation: A Jurisdictional Survey*, report prepared for the Ontario Energy Board and filed in OEB Case EB-2010-0249, May 2010, for a survey of reliability PIMs.

See Kaufmann, L., *Service Quality Regulation for Detroit Edison: A Critical Assessment*, Michigan PSC Case No. U-15244, report prepared for Detroit Edison and Michigan Public Service Commission Staff, March 2007, for a survey of customer service PIMs.

Customer Service

Customer service PIMs have used a wide array of metrics. These have included results of customer satisfaction surveys, customer complaints to the regulator, telephone response times, billing accuracy, timeliness of bill adjustments, and the ability of the utility to keep its appointments.

Performance on these metrics is often assessed through a comparison of a company's current year performance with its recent historical performance. Because of a lack of standardization in customer service data and the effort required to process available data, benchmarking a company's performance on service quality PIMs is complicated.

Energy Efficiency

Energy efficiency ("EE") PIMs tie the revenue of a utility to indications of success in its EE programs. Sensible performance metrics for such PIMs include the total MWh of load. In either case, the focus is typically on the *change* in the metric attributable to EE.

The success of a utility conservation program depends partly on kWh of load savings achieved and partly on program cost per kWh saved. Some EE PIMs have a "shared savings" format that can guard against excessive program cost. Net benefits of programs are calculated, and these are shared mechanistically between utilities and their customers.

PIMs can strengthen incentives for utilities to embrace EE. Revenue decoupling and LRAMs can remove the throughput disincentive to resist EE, whereas EE PIMs can provide a *positive* incentive to embrace EE instead of costly alternatives.

However, EE PIMs also have some disadvantages. As with LRAMs, the calculation of load savings from EE and their cost impact is generally expensive and can be controversial. Independent verification of savings is often required. PIMs for EE therefore typically exclude many kinds of EE programs (e.g., customer information programs) that have impacts that are hard to accurately calculate. Utilities are incentivized to focus on programs addressed by the PIMs and may neglect programs that the PIMs do not address.

In their 2022 State Energy Efficiency Scorecard, the American Council for an Energy-Efficient Economy found that 28 states had some form of performance incentives for electric DSM programs.[14] The incentives surveyed encompassed management fees as well as PIMs.[15] Among DSM PIMs, those focused on EE programs are the most common, and some states have decades of experience with them.

Under existing PIMs, utilities are often rewarded for the estimated load reductions they achieve beyond a threshold level of savings. Some PIMs also penalize utilities for failing to achieve load reduction targets.

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[14] Sagarika Subramanian, et al., 2022 State Energy Efficiency Scorecard, American Council for an Energy-Efficient Economy Report (Dec. 2022), https://www.aceee.org/research-report/u2206.

[15] Management fees reward the electric company for spending on specific programs, sometimes by providing them a share of expenditures. See Section 6, *infra*, for further discussion of this general approach to PBR.

Cost

Regulators in several countries use statistical cost benchmarking in rate setting. In a benchmarking exercise, the utility's historical and/or proposed future costs are compared with a benchmark that is based on statistical research. The difference or ratio is a measure of cost performance. Revenue may be adjusted on the basis of the appraisal.

The total cost, O&M expenses, capex, and/or total expenditure (O&M plus capital cost expenditure) performances of utilities have been benchmarked in the rate proceedings of various countries worldwide. Utilities may be ordered to submit benchmarking studies or may file them voluntarily in hopes of improving regulatory outcomes. Regulators have also commissioned benchmarking studies. Studies are often conducted by specialized consultants.

Benchmarking has been performed with various tools that include econometric cost models, data envelopment analysis, and simpler unit cost and productivity metrics. In North America, econometric benchmarking is facilitated by the extensive data that the FERC has gathered over many years on the operations of numerous U.S. electric utilities. Analogous data are gathered at the state level on the operations of natural gas utilities.

In Britain, extensive benchmarking is undertaken both at the level of total expenditures and by cost category. In Ontario, benchmarking is undertaken annually to appraise the cost performance of the province's power distributors. The results of these studies are used to update the stretch factor terms in these distributors' MRPs.[16] Distributors must use the commission's own total cost benchmarking model to appraise their forward test year cost proposals. Benchmarking has been used to date chiefly in the context of multiyear year rate plans but also makes sense in the absence of such plans.

5.3 Performance Metrics Implementation

Performance metric systems have notable benefits as additions to utility regulation, but must be well designed to avoid pitfalls.

Benefits

- PIMs can strengthen financial incentives to perform well in targeted areas that matter to regulators, customers, and the general public. Even in the absence of explicit financial incentives, utilities that try to perform well in targeted areas can garner valuable goodwill.
- Metric systems can evolve incrementally and gradually as new performance concerns arise and older concerns recede.

[16] More discussion of the use of benchmarking in Ontario can be found in Lowry, M.N., Makos, M., Deason, J., and Schwartz, L., 2017. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," for Lawrence Berkeley National Laboratory, Grid Modernization Laboratory Consortium, U.S. Department of Energy, https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

- Other means of strengthening incentives and/or reducing regulatory cost may be less feasible. For example, incentivization of energy cost trackers by such means as a partial passthrough mechanism can be difficult because these costs are volatile. A PIM for energy conservation programs is an alternative.

Implementation Considerations

One disadvantage of performance metrics and incentives is that performance is often difficult to measure accurately. Some utility activities are hard to quantify. Some performance metrics (e.g., reliability, sales volumes, and peak loads) are sensitive to external business conditions, and these conditions are sometimes volatile. The utility is not then fully responsible for apparent failures and successes. Standardized data on metrics and business conditions that affect them are often unavailable for numerous utilities so that peer group benchmarking is not practical.

It can also be difficult to correctly *value* performance and establish appropriate award/penalty rates for PIMs. The value of changes in performance (e.g., improved service quality and reductions in carbon emissions) is sometimes unclear. Even if it were known, the share of benefits that utilities should receive may be unclear. Concern about overpayment for performance has prompted many consumer advocates to oppose PIMs with awards.

Other issues to consider when implementing PIMs include the following:

- Utilities are incented to resist PIMs involving penalties and to propose lenient targets, while consumer groups are incented to resist PIMs involving awards and to propose aggressive targets.
- Raising targets after a utility achieves them can weaken incentives, a practice that is sometimes called "ratcheting."
- When there are multiple PIMs, the incentives they generate may overlap. Assigning sensible proper weights to individual PIMs can be difficult.

These realities of PIM design have consequences.

- The design and operation of PIMs can invite controversy and strategic behavior by parties to regulation. For example, utilities and other parties to regulation have sometimes disagreed on the load impact of EE programs that are addressed by PIMs.[17] Awards and penalties have sometimes been disputed when metrics have been influenced by external business conditions.
- The incremental regulatory cost of adding several metrics and PIMs to a regulatory system can be non-negligible. A performance metric system can in principle grow so large and complex as to constitute an undue administrative burden.

[17] Gold, R., Penalties in Utility Incentive Mechanisms: A Necessary 'Stick' to Encourage Utility Energy Efficiency? *The Electricity Journal*, November 2014, p. 89.

- PIMs may focus on more quantifiable performance dimensions and neglect dimensions that are less quantifiable but nonetheless worthwhile.

5.4 Performance Metric and PIMs in Practice

Approved performance metric systems reflect these considerations.

- PIMs tend to be limited to situations where incentives are unusually weak and performance really matters. In searching for incentive "gaps," the full range of structural, command and control, and PBR provisions of the regulatory system should be considered.
- The need for PIMs tends to be greater to the extent that the regulatory system otherwise has weak incentive power. For example, the need for DSM PIMs is greater in the absence of revenue decoupling or an LRAM. The need for PIMs to encourage low carbon electrification is greater to the extent that utility benefits of such programs are reduced by decoupling.
- PIMs also tend to be used where they are easy to develop and administer.
- Many metrics in a performance metric system will have targets but no PIMs. Some metrics will have neither targets nor PIMs.
- Complex calculations are often eschewed in PIM design. For example, the award and penalty rates of service quality PIMs rarely reflect sophisticated calculations of the costs or benefits of changes in quality. California's Public Utilities Commission abandoned the complicated shared savings approach to the calculation of awards for DSM programs.
- Some PIMs have dead bands or adjustments like Z factors to reduce the impact on awards and penalties of volatile external business conditions. For example, many reliability metrics exclude major event days because these days are typically the result of unusually severe weather or other extraordinary events.
- Awards and penalties are often small, and rewards may be arbitrarily capped.

5.5 New Uses for Metrics

Interest in using performance metrics in utility regulation has been growing in the U.S., spurred in part by the elaborate performance metric system in Britain's RIIO approach to energy utility regulation. The term RIIO stands for Revenue = Incentives + Innovation + Outputs. Outputs is the British term for their system of performance metrics and PIMs. RIIO includes numerous PIMs and many additional metrics. Some of the PIMs are quite innovative.

Metric systems are evolving to meet new industry challenges. Metrics that address special concerns of policymakers are sometimes called policy metrics. These metrics are sometimes used to construct PIMs. The new policy PIMs are usually asymmetrical and often reward-only.

Policy PIMs are most widely used to address concerns by regulators and many stakeholders that utilities make greater use of peak load management to contain growth-related capex and facilitate greater reliance on intermittent renewable resources. These PIMs may focus on the systemwide peaks that affect generation and transmission costs or on the local peaks that affect distribution costs. DSM and DERs are sometimes called "non-wire alternatives" to capex solutions.

In an age when many utilities are investing in AMI and other smart grid facilities, policymakers want to know if these facilities work well and are properly utilized. AMI benefits include reductions in consumption on inactive meters, unaccounted-for energy use, and lower meter reading costs. Regulators in some states (e.g., Illinois) have approved PIMs that address AMI performance.

Policy PIMs have also addressed the quality of service to DER customers and beneficial electrification. Beneficial electrification PIMs are one way to strengthen incentives to encourage beneficial electrification when the corresponding revenue is decoupled.

6. Targeted Incentives for Underused Practices

6.1 Underused Inputs and Practices

"Underused" is the term we use for inputs utilities often use in suboptimally small amounts. Examples include inputs that reduce capex on balance or that reduce costs that utilities are less motivated to contain because they are tracked or external to the company's finances.

Utilities can be encouraged to make greater use of disfavored inputs by various means that include the following:

- tracking their cost for prompt recovery (or deferred recovery with interest);
- adding a return on equity ("ROE") premium to the capitalized revenue requirement;
- paying the utility a "management fee" to use the inputs (e.g., O&M expenses may be amortized or utilities may receive a payment equal to a share of their targeted expenditures);[18] and
- providing ex ante approval for innovative or underused practices through such means as pilot programs.

It is, of course, possible for measures encouraging use of disfavored inputs to result in their *overuse*. Tactics to discourage overuse include careful prudence oversight. DSM shared savings PIMs can guard against inefficient DSM programs when their costs are tracked.

6.2 Salient Precedents

Many utility costs have been tracked based in part on the view that the inputs are underused. For example, tracking of utility DSM program costs is commonplace, and these expenses have been capitalized in several jurisdictions. Here are additional activities that could in principle be addressed by cost tracking or management fees based on the same reasoning:

- maintenance and refurbishment expenses that delay capex;

[18] ROE premia and expenditure share awards may be linked to performance metrics and targets.

- support for beneficial electrification;
- accommodation of DERs on the customer side of the meter;
- payments to customers for DER power surpluses;
- payments to energy service companies for DSM services; and
- utility capex for new technologies (e.g., AMI and storage capacity) that might lower total capex.

In Great Britain, capitalizing a share of all expenses, a practice known as total expenditure or "totex" accounting] is used instead of the traditional North American practice of capitalizing only a small share of O&M expenses and all capex. Under totex accounting, a share of all eligible expenditures is capitalized.

7. Multiyear Rate Plans

Multiyear rate plans (MRPs) are complex regulatory systems with essential characteristics and numerous optional provisions. We provide an overview of MRPs first before discussing precedents, MRP design issues, MRPs for the energy transition, and MRP pros and cons in the sections that follow.

7.1 The Basic Idea

Essential Characteristics

Multiyear rate plans have the following essential characteristics.

- A **r**ate review moratorium is established. These reviews are typically held every three to five years, but plan terms of eight and ten years have been approved.
- There is usually a need for utility revenue to grow between rate cases, as we discussed in the revenue decoupling section. In an MRP, an attrition relief mechanism ("ARM") permits rates or revenue to grow in the face of such pressures without closely tracking the cost that the utility actually incurs. For example, rates could be escalated for price inflation.
- Costs that are difficult to address with the ARM may instead be addressed using trackers and associated rate riders or deferrals. Costs scheduled *in advance* for tracker treatment are sometimes said to be Y factored. Y-factored costs typically include those for generation fuel and purchased power and frequently also include pension and other benefit expenses.
- Revenue adjustments are typically also permitted for hard to foresee events that are largely beyond utility control but affect utility finances. These events are sometimes said to be Z factored. Events commonly eligible for Z factoring include major storms, changes in accounting standards, highway construction programs, and changes in taxes and regulatory policies.

Other Provisions

A number of other provisions are sometimes added to MRPs. These may include:

- revenue decoupling and/or lost revenue adjustment mechanisms;

- PIMs linking the utility's revenue to its reliability and customer service performance;
- additional performance metrics and PIMs;
- an earnings sharing mechanism ("ESM") that shares surplus or deficit earnings (or both) with customers when the utility's rate of return on equity varies from the commission-approved target;
- off-ramp mechanisms that permit reconsideration and possible suspension of a plan under pre-specified outcomes such as extreme ROEs;
- targeted incentives to use underused practice; and
- plan termination provisions.

In practice, the revenue from an energy utility MRP typically does not vary too far from the utility's cost for an extended period. Utilities generally prefer a cost basis for rates, while consumer groups are uncomfortable when the ROE exceeds its target for an extended period.

7.2 MRP Precedents

MRPs have been used in North America since the 1980s. They were first used on a large scale on this continent for railroads and incumbent telecommunications carriers. Companies in these industries faced significant competitive challenges and complex, changing customer needs that complicated COSR. MRPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn superior returns for superior performance. In the United States, both industries achieved rapid productivity growth under MRPs. The FERC has used MRPs for many years to regulate oil pipelines.[19]

MRPs have also been used on many occasions to regulate retail services of gas and electric utilities.[20] In the United States, California has used these plans since the 1980s, and MRPs became popular in some northeastern states (e.g., Maine, Massachusetts, and New York) in the 1990s.

Figure 3a shows American states that have recently used MRPs to regulate retail gas and electric services.[21] It can be seen that these plans are now a fairly common alternative to COSR. Energy distributors operate under MRPs in California, Massachusetts, and New York. Use of MRPs has spread to VIEUs in diverse states that include Georgia, Hawaii, Minnesota, North Carolina, South Dakota, Vermont, and West Virginia. A law in Washington state requires utilities to propose MRPs with their rate cases.

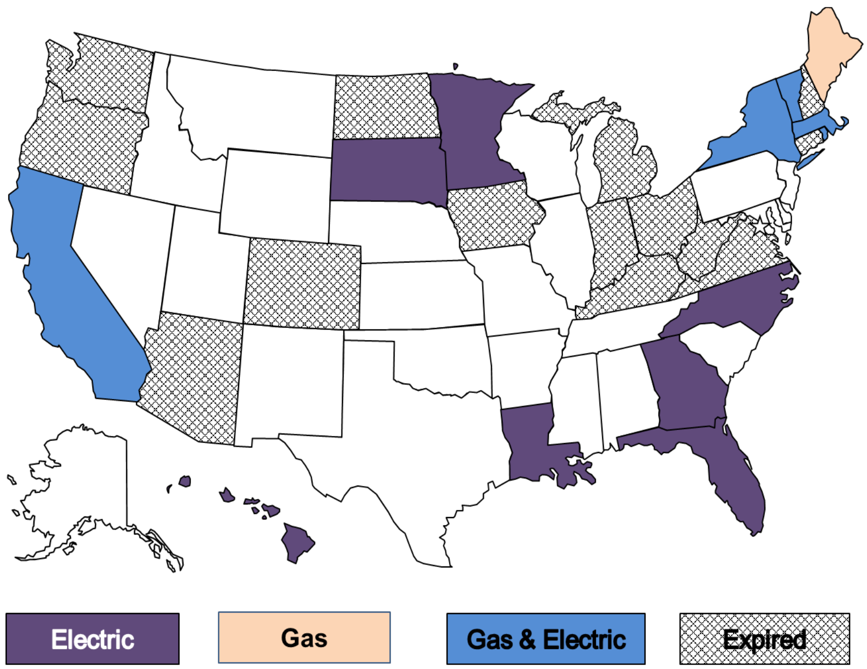
[19] See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM20-14-001, January 2022.

[20] MRP precedents for electric utilities have been monitored by the Edison Electric Institution in a series of surveys. The most recent is Lowry, M. N., Makos, M., Waschbusch, G., and Cohen, B., 2024. "Innovative Regulatory Tools for Addressing an Increasingly Complex Energy Landscape: 2023 Update," for Edison Electric Institute.

[21] These maps reflect the status of North American MRPs ca October 2024.

Figure 3a

Recent MRPs for Energy Utilities in American States*



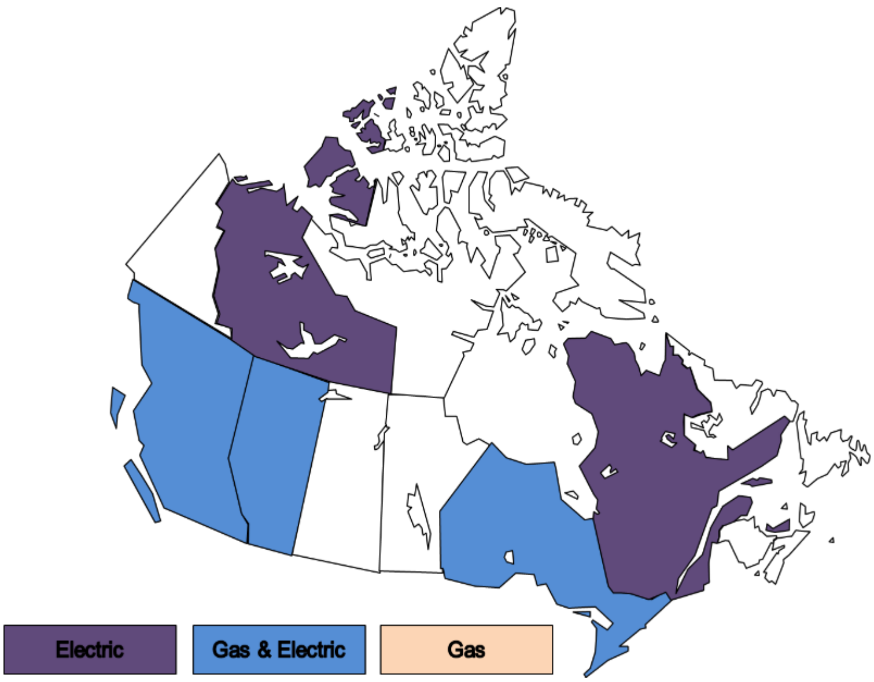
Rate regimes in Illinois, Maryland, and the District of Columbia are *called* MRPs but function more like formula rates due to fine-print "cost reconciliation" mechanisms that are not characteristic of MRPs. These mechanisms raise regulatory cost and weaken cost-containment incentives. A proceeding in Maryland to reconsider this ratemaking approach has revealed widespread dissatisfaction.[22]

Figure 3b shows that MRPs are even more widely used to regulate energy utilities in Canada. Alberta, British Columbia, and Ontario were early innovators and continue to use MRPs. Overseas, MRPs are the norm in many English-speaking countries (e.g., Australia, Ireland, New Zealand, and the United Kingdom). Great Britain's RIIO approach to ratemaking has drawn considerable interest in the United States. Countries in continental Europe which have used MRPs to regulate energy utilities include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden. MRPs are also common in Latin America.

[22] See, for example, the September 16, 2024, comments by the Staff of the Public Service Commission in Maryland Public Service Commission Cases 9618 and 9645.

Figure 3b

Recent MRPs for Energy Utilities in Canadian Provinces



7.3 Attrition Relief Mechanisms

The attrition relief mechanism is one of the most important components of an MRP. In this section we discuss salient approaches to ARM design.

Rate Caps vs. Revenue Caps

ARMs can escalate rates or allowed revenue. Limits on rate growth are sometimes called "price caps" and have been widely used to regulate industries, such as telecommunications, where it is desirable for utilities to market their services aggressively and promote system use. Aggressive marketing is generally welcomed to the extent that utilities have excess capacity and use of their systems does not involve negative externalities.

Under *revenue* caps, the ARM permits growth in the revenue requirement. The allowed revenue yielded by the ARM must be converted into rates, and this conversion requires assumptions regarding billing determinants such as the delivery volume and the number of customers served. Revenue caps are often paired with a revenue decoupling mechanism.

Approaches to ARM Design

There are several well-established approaches to ARM design. Most can be used, with modifications, to escalate rates or revenues. To simplify the discussion of ARM design approaches we assume that most are used to design *revenue* caps. Summaries of the ARMs and other provisions of the MRPs of several utilities can be found in the Appendix.

Stairstep ARMs

The Basic Idea

Under a stairstep ARM, revenue requirement increases are determined in advance (e.g., 4% in 2025, 5% in 2026, and 3% in 2027). Stairsteps can be based on various methods. One is a multiyear cost forecast or proposal. These cost forecasts are sometimes conditional on an inflation assumption as in the formula $Cost^{Forecasted} = Cost^{Real\ Forecasted} \times (1+Inflation^{Forecasted})$. The MRP just approved for the Canadian power distributor Toronto Hydro is illustrative.[23] The revenue requirement may then be subject to a true up when the actual inflation rate becomes known.

Familiar accounting methods can be used to design stairsteps for capital revenue. The trend in the cost of older capital is relatively easy to forecast since it depends chiefly on mechanistic depreciation. The more controversial issue, and a major focus of a typical proceeding to approve a stairstep ARM, is the assumed value of gross plant additions during the plan term.

Some regulators resist extensive use of multiyear cost forecasts in ARM design. Due to concerns about uncertain or exaggerated capex forecasts, capital cost underspends are sometimes refunded to customers. In lieu of multiyear cost forecasts, some stairstep ARMs for capital revenue have instead been based on an average of the utility's recent historical gross plant additions or a repetition of the gross plant additions proposed for the test year in each subsequent year of the plan. In each case, the additions may be adjusted for inflation or customer growth.

Precedents for Forecasted ARMs

Stairsteps are a common basis for ARM design in MRPs of American electric utilities. They are currently used by electric utilities in California, Georgia, Minnesota, and New York. The British regulator's use of forecasts in ARM design is sometimes called the "building block" approach since the revenue requirement is built up from forecasts of component costs.

Indexed ARMs

The Basic Idea

The indexing approach to ARM design is based primarily on industry cost trend research. Research has revealed over the years that trends in utility costs display patterns that can often provide the basis for just and reasonable adjustments to rates or revenue between rate cases. Cost trends are usually decomposed into input price and productivity trends using indexes.

The following result from cost theory is useful in the design of revenue cap indexes:

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Scale} - \textit{growth Productivity}. \qquad [1]$$

The growth (rate) of cost is the sum of growth in input prices and operating scale less the growth in productivity. Equation [1] provides the basis for the following general revenue cap index formula:

[23] Ontario Energy Board Case EB-2023-0195.

$$growth\ Revenue = Inflation + growth\ Scale - (X + Stretch) + Y + Z. \qquad [2]$$

Here *X*, the "X factor," typically reflects the historical productivity trend of a group of utilities. Revenue escalation is therefore limited by an external productivity growth standard. A stretch factor (aka customer or consumer dividend) is often added to the formula to guarantee customers some of the benefit of the stronger performance incentives expected under the plan. Growth in scale is usually measured by the number of customers served.

To decide on a value for X, regulators typically want to learn about utility productivity trends by considering one or more multifactor productivity studies. Trends in the multifactor productivity ("MFP") of broad national or regional peer groups are commonly used to establish the base productivity trend. These studies can be commissioned by the utility, the commission, and/or intervenors.

In United States MRPs, the inflation measure in an indexed ARM is often a macroeconomic price index such as the gross domestic product price index ("GDPPI"). The propensity of the GDPPI to track industry input prices becomes an issue. This is a particular concern because GDPPI growth is materially slowed by the MFP growth of the economy and is to that extent an inaccurate measure of the economy's input price growth. A term can be added to the revenue cap index to correct for the tendency of the GDPPI to understate utility input price inflation. This adjustment can be part of the X factor, but this approach is likely to make the X factor negative, conveying the misimpression that the commission has chosen a lax productivity growth standard.

Most productivity studies used in ratemaking have focused on gas and electric power distributors. However, studies have also been commissioned on the productivity trends of generators, power transmitters, and vertically integrated electric utilities.

Supplemental Capital Revenue

Since indexed ARM formulas reflect the longer term capital productivity growth trend, they may not fund surges in capex such as may result from higher reliability and resiliency standards or an outsized need to replace aging facilities. Utilities expecting to operate under indexed ARMs therefore frequently ask for and often receive supplemental capital revenue. This supplement can materially weaken capex containment incentives if accorded tracker treatment.

Precedents for Indexed ARMs

The indexing approach to ARM design originated in the United States.[24] Development was facilitated there by the availability of standardized, quality operating data for numerous companies in several utility industries. First applied in the railroad industry, indexed ARMs have subsequently been used on a large scale to regulate telecommunications utilities and oil pipelines.

California, Maine, and Massachusetts were early adopters of indexed ARMs in retail energy utility regulation. Energy utilities that have operated under such ARMs include Bay State Gas, Boston

[24] Early American papers discussing the use of price and productivity research to design ARMs include Sudit (1979) and Baumol (1982).

Gas, Central Maine Power, Eversource (MA), the Hawaiian Electric companies, NSTAR Electric, NSTAR Gas, National Grid (MA), San Diego Gas & Electric, Southern California Edison, and Southern California Gas.

ARMs based chiefly on index research are now used more widely to regulate utilities in Canada than in the United States. The Canadian Radio-television and Telecommunications Commission was an early adopter. Energy utilities have used indexed ARMs in Alberta, British Columbia, Ontario, and Québec.

Hybrid ARMs

"Hybrid" approaches to ARM design use a mix of index research and stairsteps. A popular hybrid approach in the United States involves separate treatment of the revenue that compensates utilities for their O&M and capital costs. Indexes address O&M expenses while stairsteps address capital cost. We call this the "old-school" California approach since it has been used occasionally in that state since the 1980s.

There is a newer approach to hybrid ARM design that we call the "index runaround". Under this approach, the entirety of allowed revenue is nominally escalated by an index but a term in the index formula effectively replaces index-based capital revenue with capital revenue based on a stairstep. A notable example comes from Alberta and Massachusetts, where an average of the utility's recent historical gross plant additions is used to calculate the alternative capital revenue stairsteps. The term in the index formula that accomplishes the runaround is called "K bar."

The rationale for both of these hybrid approaches includes the argument that indexation of O&M revenue provides protection from hyperinflationary episodes and can limit the scope of forecasting controversy to capex. Good data on O&M input price trends of utilities are available in the United States.[25] The idea of indexing a utility's O&M compensation has such appeal that it is also used sometimes to establish O&M revenue requirements in rate cases.[26]

The stairstep approach to escalating capital revenue, meanwhile, accommodates diverse capital cost trajectories. The complicated issue of designing an index-based ARM for capital revenue is sidestepped. The traditional approach to capital cost accounting can be used. There can be added advantages to separately addressing capital revenue such as a particular desire to claw back any capex underspends. On the other hand, stairsteps are sometimes based on forecasts and we have shown that capital cost forecasts can be complex and controversial.

Rate Freezes

Multiyear rate freezes that apply to rates for most costs can also be considered a class of attrition relief mechanisms. These have recently been approved for several U.S. electric utilities, most of

[25] In Canada, on the other hand, custom indexes of utility material and service prices are unavailable and government labor price indexes do not encompass pensions and benefits.

[26] For example, indexing has been used to escalate at least a portion of test year OM&A expenses in Massachusetts, New York, Rhode Island, and Tennessee.

which are vertically integrated. Provided that a few major costs that are growing are either tracked or accorded a forecasting treatment without trueup, the utility may not need further rate escalation for several years. Depreciation of the rate base for older plant and billing determinant growth help to fund growth in O&M expenses. Quite often, the tracker or forecast addresses costs of generating plant additions. The prudence of these costs needs to be carefully examined. This approach to ARM design has recently been used by VIEUs in Florida, Louisiana, and West Virginia.[27]

Z Factors

As noted in Section 7.1, a Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings and are not effectively addressed by the ARM or dedicated cost trackers. Many MRPs have explicit eligibility requirements for Z-factor events. Here is a typical list of requirements.

> <u>Causation</u>: The expense must be clearly excluded from the costs upon which rates were derived.
>
> <u>Materiality</u>: The event must have a significant impact on the finances of the utility. Materiality can be measured based on individual events or the cumulative impact of multiple events. Some plans have materiality thresholds of both kinds.
>
> <u>Outside of Management Control</u>: The cost must be attributable to some event outside of management's ability to control.
>
> <u>Prudence</u>: The cost must have been prudently incurred.

Eligible Z factor events may, in principle, raise or lower earnings. For example, a cut in corporate income taxes could raise earnings and occasion a rate reduction.

Z factors can reduce utility operating risk without weakening performance incentives for the majority of costs. Z factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most of the benefits of MRPs. Disadvantages of Z factors include the fact that they raise regulatory cost. Another disadvantage is the possibility that they may weaken utility incentives to mitigate the impacts of triggering events. Note also that, due in part to information asymmetries, it may be easier for the utility to obtain higher revenue from Z factors than it is for customers to obtain lower revenue.

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[27] See, for example, Florida Public Service Commission Docket 20210015-EI, Louisiana Public Service Commission Docket U-35299, and West Virginia Public Service Commission Case 20-1012-E-P for further details.

7.4 Other Incentive Provisions

Performance Metrics and PIMs

Performance metrics and PIMs were noted in Section 7.1 to be a common addition to MRPs. Reliability and customer service PIMs are needed to encourage the maintenance or improvement of quality in the face of stronger cost containment incentives.

Additional Incentives to Slow Load Growth

MRPs were also noted in Section 7.1 to sometimes contain revenue decoupling or LRAMs and trackers for costs of utility DSM expenses. These provisions encourage utilities to embrace DSM and DERs. MRPs often also have PIMs for DSM since these provide more “positive” incentive to use DSM to reduce load-related capex and variable costs that are tracked or external to the utility’s operations. Examples of load-related capex include new generation or substation capacity.

Targeted Incentives for Underused Inputs

MRPs often include targeted incentives for underused inputs. The stronger cost containment incentives that MRPs provide enhances concern about the underuse of certain practices. Utility DSM expenditures, for example, are commonly tracked in North American MRPs. A similar rationale supports tracking costs of accommodating DERs.

It may also make sense to track the cost of beneficial electrification, especially when the plan also includes decoupling. Trackers for beneficial electrification have been included in several MRPs. The use of totex accounting in the British RIIO approach to MRP design was noted above.

MRPs also frequently contain pilot programs that feature underused practices. While MRPs are sometimes touted for encouraging innovation, in practice utilities often worry that innovative practices might be adversely treated by regulators in the next rate case.

7.5 Earnings Sharing Mechanisms and Off-Ramps

Some MRPs include explicit controls on the earnings utilities can achieve. Two approaches to earnings control are common: earnings sharing mechanisms (ESM) and off-ramp mechanisms. These approaches can be used separately or in combination.

Earnings Sharing Mechanisms

The Basic Idea

As noted in Section 7.1, ESMs share surplus and/or deficit earnings between the utility and its customers. Such earnings arise when a utility’s ROE deviates from its commission-approved target. An earnings surplus, for example, is earnings that cause the actual ROE to exceed its target.

Numerous decisions must be made in the design of an ESM. For example, allocations of earnings variances may differ with the magnitude of the variances. Small variances (e.g., less than 100 basis points) are often not shared with customers. This provision is often called a “dead band.” Beyond the dead band there may be one or more bands in which earnings are shared in different proportions between customers and the company. An ESM may also include earnings caps and/or floors, beyond which the utility will return all further incremental earnings surpluses to customers or recover further incremental deficits.

The symmetry of sharing provisions must also be addressed. ESMs need not be symmetrical. For example, they can share only earnings surpluses or deficits. Even if an ESM shares both surpluses and deficits, the sharing provisions for these can differ.

Pros and Cons of ESMs

Whether to add an ESM to an MRP is one of the more difficult decisions in plan design since there are several noteworthy pros and cons. On the plus side, an ESM can reduce the risk that revenue will deviate substantially from cost. Unusually high or low earnings may reflect unusual utility performance, but may also reflect windfall gains or losses or a poor plan design. The reduction in risk can help parties agree to a plan and make it possible to extend the period between rate cases. In the absence of a stretch factor, an ESM provides a way to share benefits of improved performance during the plan.

On the downside, an ESM weakens utility performance incentives. ESM design also raises regulatory cost, and the ESM filings themselves can be a source of controversy. Customers may complain, for example, if the ROE never gets outside the dead band so that earnings are shared. There is less need for an ESM if the plan features other risk mitigation measures, such as inflation indexing, cost trackers for capex surges, Z factors, or revenue decoupling.

Precedents for ESMs

A recent PEG survey for the Edison Electric Institute showed that ESMs are featured in more than half of current U.S. and Canadian electric utility MRPs.[28] While some ESMs share both surplus and deficit earnings, most share only surplus earnings. This maintains an incentive for companies to become more efficient to avoid underearning. Dead bands are a common feature of ESMs. Dead bands may be used in situations where the company shares earnings surpluses, earnings deficits, or both.

Off-Ramps

The Basic Idea

Off-ramp mechanisms allow MRPs to be reconsidered before their expiration if certain events occur during the plan. The qualifying events typically involve extreme ROEs, but may instead involve other considerations such as unusual inflation or reliability events. The rules for what happens following a qualifying off-ramp event vary. A formal proceeding to reconsider plan terms may be mandatory or at

[28] Lowry, M. N., Makos, M., Waschbusch, G., and Cohen, B., 2024. "Innovative Regulatory Tools for Addressing an Increasingly Complex Energy Landscape: 2023 Update," for Edison Electric Institute.

the commission's discretion. Reconsideration may be limited to a revision of plan terms but may also include the possibility of a new rate case.

Off-Ramp Pros and Cons

Similar to ESMs, off-ramps reduce operating risk by providing a "fail safe" in case of markedly undesirable outcomes. This can help parties support the MRP. The reduction in risk that off-ramps provide can make it easier to choose other plan provisions that involve more risk but have offsetting benefits, such as stronger performance incentives. For example, the plan can have a longer term and/or not have an ESM.

On the other hand, off-ramps reduce opportunities to gain from improved performance and reduce the downside from an exceptionally bad performance. A utility could encourage a triggering event to escape an undesirable MRP. Note also that there is less need for an off-ramp to the extent that the plan has other risk-reducing provisions such as an ESM, a cost tracker for capex surges, revenue decoupling, and/or Z factor provisions.

Because off-ramps have a material downside, they should be designed carefully if used. For example, the ROE should deviate quite significantly from the commission-approved target before an off-ramp is triggered. It is desirable for a qualifying ROE variance to be extreme on average over two or more years.

7.6 Plan Termination Provisions

Plan termination provisions are one of the more important issues in MRP design. Rates are often reset in a general rate case, and this typically occurs in the last year of the plan. This option passes all benefits of any long run cost savings achieved during the plan to customers. A true up to the utility's actual cost is also welcomed if poor plan design had caused marked earnings surpluses or deficits.

The downsides of scheduling rate cases in advance are several and include the following.

- This option involves relatively high regulatory cost.
- Performance incentives are weakened. The incentive to realize longer-term gains is known to attenuate in the later years of an MRP. This occurs because utilities would in those years incur the upfront costs of performance-improving initiatives but receive few (or none) of the benefits that result.
- Scheduled rate cases can provide perverse incentives to utilities. Utilities may be incented to defer certain costs so that they are high in the test year for new rates and/or ask for supplemental revenue in the out years of the new plan.

7.7 MRPs for the Energy Transition

Where the energy transition is imminent or already underway it should be recognized that some transition costs may require special ratemaking treatment. Reasons for special treatment include inherent risk (e.g., the risk that beneficial electrification will be unexpectedly slow), government mandates, and the aforementioned utility reluctance to use certain practices such as peak load management that are particularly important during a transition. Tools to reduce risk and encourage utility support for the transition include the use of transition cost forecasts in ARM design and tracker treatment of transition costs.

While the need for special ratemaking treatments for some transition costs is widely recognized, it does not follow that *all utility costs* require such treatment. For example, it is neither necessary nor desirable to use tracker treatment of all capex or formula rates, yet these ratemaking approaches have sometimes been proposed with an energy transition rationale.

ARM design for the energy transition is a multi-step decision process:

1. What costs can be addressed mechanistically? The principal options here are indexing and capital revenue based on the utility's historical plant additions. Both of these approaches can be used in the same plan.
2. What costs require special ratemaking treatment? The principal options used by North American utilities have included the following.
    - Conventional two-way cost tracker
    - True up only underspends (one-way tracker)
    - Forecast with no true up to actuals.

ARMs resulting from this decision tree are often of hybrid character. For example, O&M revenue may be indexed while capital revenue may be based on a mix of historical capex and forecasts.

Other MRP provisions can also foster an efficient energy transition.

- Integrated resource and/or delivery system planning is a natural complement because MRPs address several years of future rates.
- Revenue decoupling can encourage DSM, DERs, and time-sensitive rates that can reduce the need for capacity expansions.
- Policy metrics & PIMs can monitor and incentivize transition progress (e.g., peak load management, resiliency, beneficial electrification, and the quality of service to DER customers.)
- Cost trackers for underused energy transition practices (e.g., DSM and the accommodation of DERs) can encourage utilities to use more of these options, especially when budgets for more traditional fossil-fueled generation capacity additions have less flexibility.
- A tracker for incremental costs of beneficial electrification can make sure that the job gets done despite strong MRP cost containment incentives.
- Pilot programs can encourage innovative transition initiatives.

Since these various MRP provisions encourage utilities to manage the energy transitions efficiently, MRPs have been a common approach to ratemaking for utilities on the forefront of the energy transition. For example, they are the norm for ratemaking in Australia, Great Britain, California, Hawaii, Massachusetts, and New York state.

7.8 MRP Case Study- Alberta Electricity Distributors

In 2012, Alberta's utility commission made MRPs mandatory for gas & electric power distributors after years of biennial rate cases produced high regulatory cost and rapid rate increases. Three generations of MRPs that they call PBR plans have thus far been approved. In the first generation plan called PBR1, the choice of an indexed ARM led to utility demands for supplemental capital revenue that was ultimately provided using expansive use of capital cost trackers. This led to high regulatory cost and high capex. In the second plan, capex trackers were replaced with the K-bar hybrid approach to ARM design discussed above. The K-bar idea was ventured by one of Alberta's commissioners. Each utility's capex budget was effectively based on a historical average of its recent past gross plant additions. Thus, higher capex did not produce higher revenue and lower capex did not lower revenue. Capex containment incentives were thereby strengthened.

A recent PEG study found that in the first generation of MRPs the multifactor productivity growth of Alberta energy distributors accelerated.[29] However, this resulted from a surge in O&M productivity. Capital productivity surged in PBR2 when capex cost trackers in PBR1 were replaced with fixed capex budgets based on historical costs, not forecasts. Figure 4 shows the MFP growth of Alberta power distributors before PBR and during the first 2 PBR plans. The K-bar approach has been continued in PBR3. Capital costs of the energy transition that are directly tied to applicable law related to net zero carbon objectives may be eligible for tracking in the new plan. Thus, distributor rate growth is limited in Alberta by a combination of indexing and K-bar with limited use of trackers for the energy transition.

7.9 MRP Pros and Cons

Advantages

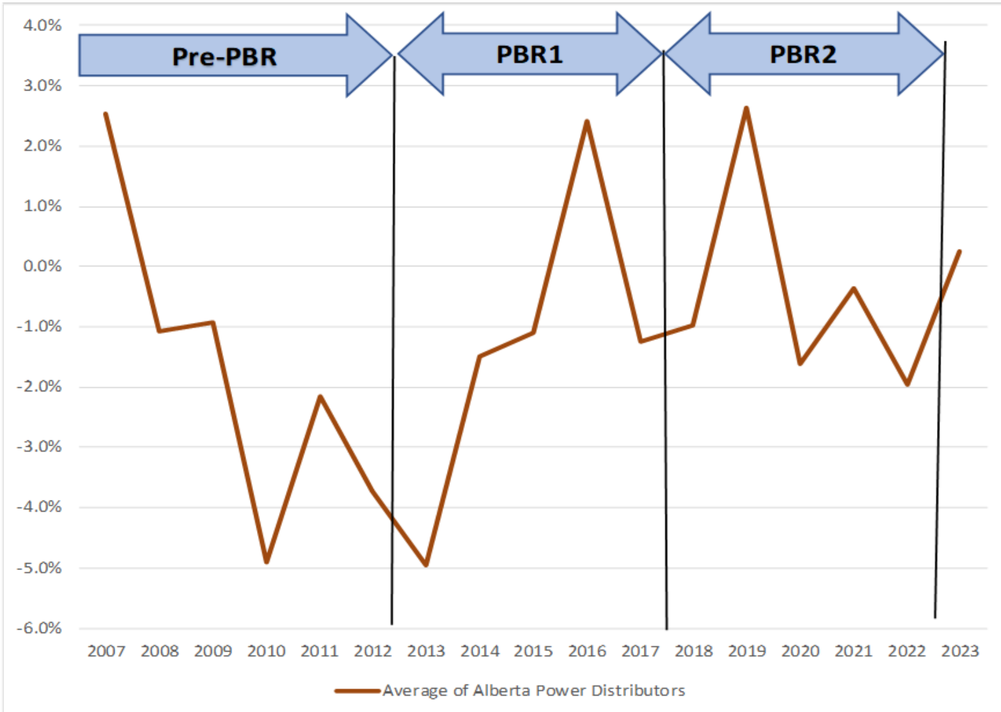
MRPs have several general advantages over COSR under modern operating conditions. The ARM can provide timely rate escalation for increasing cost pressures. The frequency of rate cases can thus be reduced without tying rate adjustments to the utility's own costs. Regulatory lag can be increased despite timely rate adjustments. This means that there are increased opportunities for utilities to bolster earnings from various efforts to contain growth in the rate base and other costs that are addressed by the ARM (i.e., costs that are not tracked). There is more incentive to buy services rather than build plant when this is the low-cost strategy. The ARM thus addresses utility financial attrition without weakening performance incentives.

Provisions can be added to MRPs which further strengthen a utility's incentive to embrace DSM and DERs. These include revenue decoupling and the tracking of utility DSM expenses. In addition MRPs can, by strengthening general incentives to contain cost, provide their own incentive for utilities to use

[29] Lowry, Mark Newton, David Hovde, Rebecca Kavan, and Matthew Makos. "Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta," The Electricity Journal, Volume 36, Issue 5, June 2023.

Figure 4

Multifactor Productivity Growth of Alberta Power Distributors 2008-2023



DSM and DERs to contain load-related costs of base rate inputs such as load-related capex. A utility might, for example, be more incentivized to use DSM and well-sited customer DERs to reduce the need for a costly distribution system upgrade. Time of use pricing has more appeal since this can help contain growth-related costs.[30] The combination of an MRP, revenue decoupling, demand-side management PIMs, and the tracking of DSM-related costs can thus provide four "legs" for the DSM "stool."[31]

The PIMs included in the plans can address "holes" in the incentive framework. For example, we have noted that MRPs can strengthen incentives to contain costs, and these include costs incurred to maintain or improve service quality and safety. In competitive markets, a producer's revenue can fall materially if the quality of its offerings falls below industry norms. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality.

With stronger performance incentives and greater operating flexibility, MRPs can encourage better utility performance. The strengthened performance incentives can encourage a more

[30] Railroads operating under MRPs used pricing provisions aggressively to encourage less costly service requests.

[31] A *three*-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in Dan York and Martin Kushler, "The Old Model Isn't Working: Creating the Energy Utility for the 21st Century," ACEEE, September 2011.

performance-oriented corporate culture at utilities. Benefits of better performance can be shared with customers via earnings sharing mechanisms, occasional rate cases, and/or careful RAM design.[32]

MRPs can also improve the efficiency of regulation. Rate cases are less frequent and can be better planned and executed. The terms of MRPs of utilities in the same jurisdiction can be staggered so that rate cases overlap less. More time is then available for each utility's rate filing. Streamlining the rate escalation chore can free up resources in the regulatory community to more effectively address other important issues. Senior utility executives have more time to attend to their basic business of providing quality service cost-effectively.

MRP Disadvantages

MRPs also have disadvantages.[33] They are complex regulatory systems that require skills that the regulatory communities in some jurisdictions do not possess. It can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise over plan design. The main sources of controversy in a typical MRP proceeding are the appropriate ARM and mechanisms for supplementing capital revenue.

MRPs also create opportunities for strategic behavior that erode potential plan benefits for customers. Utility cost forecasts may be upward-biased. Utilities may defer costs until the later years of the plan when they are more likely to raise future rates. Customer protections against these strategies such as earnings sharing weaken cost containment incentives.

These and other concerns have prompted many consumer advocates to oppose MRPs. Best practices in the MRP approach to regulation have evolved to address many of these problems. However, the efficacy of many of these remedies is not yet assured.

8. Application to Virginia

8.1 Virginia's Investor-Owned Electric Utilities

Virginia's new study of PBR is intended to consider its application to Dominion Energy Virginia ("DEV") and Appalachian Power ("APCo"). We begin this section by providing a discussion of these two vertically integrated electric utilities.

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[32] Customers can also benefit from the more predictable rate growth that MRPs make possible. Rate trajectories can be sculpted to diminish rate bumps.

[33] For further discussion of disadvantages of MRPs see Costello, K., *Multiyear Rate Plans and the Public Interest*, for National Regulatory Research Institute, October 2016 and Lowry, M. N., and Woolf, T., *Performance-Based Regulation in a High Distributed Energy Resources Future,* for Lawrence Berkeley National Laboratory, January 2016.

Dominion Energy Virginia

DEV is a large VIEU that serves areas of central and eastern Virginia and northeast North Carolina. The company serves most of the Richmond and Hampton Roads metropolitan areas and southern suburbs of Washington, DC.

In 2023, DEV served 2.75 million customers and sold 89 GWh of power. Industrial sales and sales for resale account for a relatively small share of the Company's total sales. Sales to commercial customers and public authorities, on the other hand, account for an unusually large share that reflects numerous federal government facilities and data centers in areas served. DEV's demand growth is forecasted to be brisk, primarily driven by the expansion of data centers. However, average use of power by DEV's residential customers has been declining for many years.

In 2023, the company's net generation accounted for a substantial 74% of its power supply. The company now produces most of its power using natural gas and nuclear fuel.

The Commission found that DEV's DSM programs had achieved about 1.2% savings in 2022 as a share of 2019 total annual sales. DEV reports that its DSM programs achieved about 1.4% savings in 2023. In both years, this is less than the target mandated in the law. Targets for the period beyond 2025 are currently being discussed in Case No. PUR-2023-0227. DEV has proposed targets for the 2026-2028 period that are lower than those effective for 2025.

Appalachian Power

APCo is a medium-sized VIEU based in Charleston, West Virginia. It serves most of southern West Virginia and southwestern Virginia. The company's Virginia service territory is a region where most customers live in small and medium-sized towns and rural areas. Roanoke, the largest metro area served, had an estimated population of 314,314 in 2023.

In 2023, about 58% of the roughly 32,000 GWh of power the company supplied in both states was self-generated. Most of APCo's generation comes from coal-fired power plants in West Virginia. A sizable share of the Company's power purchases come from coal-fired power plants. Compared to DEV, industrial sales and sales for resale account for a much larger share of APCo's total sales.

APCo provides EE and peak shaving programs to its customers. For 2022, APCo's DSM programs achieved more than 1.5% savings as a share of 2019 total annual sales. APCo has reported that their DSM programs achieved about 2.4% savings as a share of 2019 sales for 2023. These results exceeded their targets mandated in the law. Targets for the period beyond 2025 are currently being discussed in Case No. PUR-2024-00134. APCo has proposed targets that are lower than those effective for 2025.

8.2 Virginia Regulation

Regulation of the utilities features a complicated mix of structural, command and control, and incentive provisions. We summarize some salient provisions of each kind in turn.

Structural Policies

In the late 1990s Virginia's legislature took steps in the direction of separating the utilities' generation, transmission, and distributor services. While the utilities' rates were unbundled into generation, transmission, and distributor services, they were never required to divest their generation assets. The current structure of the electric utility industry is outlined in the Virginia Electric Utility Regulation Act of 2007. DEV and APCo make all deliveries of power to retail customers in the areas that they serve. For the vast majority of customers, DEV and APCo's service also includes power supply. Some large volume customers are permitted to buy power from other suppliers.

Customers have generally been free to own DERs up to specified individual capacity limits. However, the SCC is currently reconsidering net metering for APCo and will do so for DEV next year.

State law requires APCo and DEV to join a regional transmission entity. Both have joined the PJM Interconnection. Transmission line construction has engendered controversy.

Command and Control Regulation

Grid Transformation and Security Act

In 2018, the Grid Transformation and Security Act required the utilities to submit distribution grid transformation plans that include measures to facilitate integration of DERs and to enhance distribution grid reliability and security. Each utility was also authorized to propose electric grid transformation projects and recover the costs of these projects in a tracker. Eligible investments include AMI, intelligent grid devices, automated control systems for distribution circuits and substations, cyber security measures, communications networks for service meters, certain distribution system hardening projects, physical security measures at key distribution substations, certain energy storage systems and microgrids, and infrastructure for EV charging systems.

A share of the capacity from solar facilities was required to be purchased from 3rd parties. All solar generation in Virginia that was subject to these provisions must be acquired as part of a competitive procurement, but the utility may select solar generation capacity on factors other than the lowest cost if the selection of such a project materially advances non-price criteria so long as that capacity does not exceed 25% of the utility's solar capacity. The utilities were also authorized to undertake a test or demonstration project for a utility-owned and operated offshore wind facility.

The utilities were also required to design and implement energy efficiency programs and to spend minimum amounts on these programs. At least five percent of the spending must be made on programs for low-income, elderly, and disabled individuals.

Virginia Clean Economy Act

The Virginia Clean Economy Act of 2020 ("VCEA") made several important changes to the operating and regulatory environment of the utilities. These changes generally encouraged improved environmental performance. The act mandated that all of the utilities' Virginia coal-fired generation be retired by the end of 2024 unless the plant was jointly owned by DEV and a cooperative utility or owned and operated by DEV in a coalfield area of Virginia. All generating stations that emit carbon as a byproduct of burning fuel to generate electricity are to be retired by the end of 2045 for the utilities. The utilities may request waivers from the Commission if such retirements threaten the reliability or security of service to customers. The social cost of carbon must be considered in any applications and Commission decisions on new generating capacity, and the Commission was given the authority to determine the social cost of carbon. The Commission must also ensure that the development of new or the expansion of existing energy resources or facilities does not have a disproportionate adverse impact on communities that have been historically disadvantaged.

Each utility is required to petition the Commission to construct, acquire, or enter into agreements to purchase the energy, capacity, and environmental attributes of a certain amount of generation from solar and/or onshore wind in coming years. There are interim targets for APCo and DEV to request approvals of a certain amount of renewable generation from solar and onshore wind and targets for 35% of these projects to be owned by 3rd parties. The legislature set a goal that at least 10% of the energy storage capacity be behind the meter. The utilities are also required to annually undertake requests for proposals for new solar and wind resources. Evaluation criteria for any bids must meet various criteria outlined in the legislation. Annual filings showing how the plan will be implemented are also required. The resulting costs are eligible for tracker treatment.

The VCEA also addressed affordability concerns. A percentage of income payment program was established which caps bills for eligible low-income residential customers at 6% of their income if their source for home heating is not electric and 10% if it is. Differences between the tariffed rates and these discounts are addressed by the universal service fee which is charged to all retail customers.

Some net metering provisions were also addressed by this legislation. Caps on the generation capacity of individual customers were increased. The cap on total net metering installations was increased to 6% of the utility's peak load capacity. Once that cap is reached or in 2024 for APCo and 2025 for DEV, whichever is earlier, a net metering proceeding must be held which will determine the amount customer-generators must pay for their use of the grid, the amount the utility must pay for the power generated by net metering customers, and the benefits that the net metering facilities provide.

An energy efficiency resource standard ("EERS") was established, with annual EE targets through 2025 based on each utility's 2019 sales levels. For years after 2025, the SCC will establish targets for three-year periods based on studies of potential savings from cost-effective programs and measures.

The VCEA also established a renewable portfolio standard ("RPS") with annual targets for the share of electricity sold that must be generated from renewable resources (e.g., solar, wind, hydro, anaerobic digestors).[34] To comply with the RPS, each utility must procure and retire renewable energy certificates ("RECs") from eligible renewable resources. Beginning with the 2025 RPS compliance year, at least 75% of DEV's clean energy must come from eligible resources in Virginia.[35] The RPS requirement

[34] Va. Code Ann. § 56-585.5. C. 2020.

[35] This requirement does not apply to APCo.

for DEV in 2024 is 23%, while that for APCo in 2024 is 10%. By 2030 DEV's RPS target increases to 41%, and hits 100% in 2045 and years afterwards. APCo's RPS target does not reach 100% until 2050. Failure to meet the RPS target will result in a penalty and such penalties may be included in rates. Trackers were authorized to address the costs of RPS compliance if these costs are not already eligible for tracker treatment.

Integrated Resource Planning

State statutes require the utilities to file updated integrated resource plans ("IRPs") by October 15th of the year preceding their periodic rate reviews. Starting in 2024, utilities are also required to submit annual IRP updates for the year that they are undergoing a rate review. The minimum requirements of IRPs are set out in state statutes. An IRP must include a forecast of load obligations and how the utility expects to meet those obligations using supply and demand side resources over the next 15 years to promote reasonable prices, energy independence, and environmental stewardship. IRPs should consider purchases from affiliates and third parties, demand response, and the use of energy storage as well as a utility's self-generation. Utilities should use a diverse mix of power supply options and cost-effective demand response to reduce the risks associated with an over-reliance on any particular DSM or power supply option. Currently, the code only requires competitive procurement solicitations for the RPS resources, any other resources are not subject to competitive solicitations.

Rate Regulation

Rate Reviews

When restructuring occurred in the 1990s, the utilities' rates were unbundled and subject to a base rate freeze that was not fully lifted until passage of the Virginia Electric Utility Regulation Act of 2007. Many provisions of Virginia electric utility rate regulation can be found in this act, which has been periodically amended.

For most customers, base rates for generation and distributor services are updated through a process called "rate reviews." State law has often limited the Commission's flexibility to undertake these reviews. For example, it requires the timing of DEV and APCo rate reviews to be staggered. It also limits the amount of time the Commission has to conduct a proceeding and issue its decision on a rate review.

Rate reviews have usually been on a biennial basis. However, in 2015, a senate bill enacted lengthy base rate freezes for DEV and APCo. During these freezes, existing cost trackers continued to operate and there was no prohibition on the proposal of new trackers. DEV's initial rates exceeded the cost of service. DEV achieved high earnings during this period that could not be clawed back.

State law created new rules for rate reviews in 2023. Reviews are now biennial and look backwards and forwards.[36] For example, DEV's rate review in 2023 considered the Company's earned

[36] In other jurisdictions, rate cases only attempt to set rates that are just and reasonable for the rate year or rate years, which starts when new rates become effective after a final decision on a rate case application has been issued. Unless a utility is brought in due to a complaint of overearnings, rate cases do not typically involve a review of a utility's recent earnings performance.

ROE in 2021 and 2022, and the Company presented evidence supporting the need for rate increases for 2024 and 2025.[37] The forward-looking portion of a rate review allows the Commission to change rates such that the utility's projected earnings for the next biennium will be neither excessive nor insufficient. The backwards-looking portion of a rate review is functionally similar to an ESM for the expired biennium. State law has outlined earnings sharing provisions to be used for the backwards-portion of the rate review for each utility.

Cost Trackers

A review of DEV's tariffs shows that the Company has more than 20 trackers, while APCo has less than 15 trackers. In Virginia, trackers are often referred to as rate adjustment clauses ("RACs"). Trackers address costs that are commonly tracked in American ratemaking, such as those for fuel and purchased power. Both utilities also have trackers to address the costs of demand response programs, to support broadband capacity extensions in rural areas, and lost revenues from discounts to low-income customers.

DEV also has several trackers for capex projects, including presently two for gas-fired combined cycle plants, one for offshore wind, several for solar generation, one for distribution undergrounding, one for distribution "grid transformation", and one for extension of the service lives of nuclear generating units. APCo does not have any trackers to address the costs for distribution projects. However, it has trackers for costs related to environmental, renewable portfolio standard compliance, and generation projects.

Dominion has estimated that by 2026 most of its Virginia-jurisdictional generation and distribution rate base will be addressed by trackers.[38] Under status quo ratemaking that percentage is likely to increase, as Dominion forecasts that 75% of its $35.5 billion capital plan for the 2025-2029 period will be eligible for tracker treatment.[39]

The utilities' charges for transmission services are regulated by the FERC using formula rates. We noted above that these are tantamount to comprehensive cost trackers. There are trackers in retail rates to recover the portion of each utility's transmission costs that are assigned to retail ratepayers.

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[37] The Company did not actually propose a rate increase for 2024 and 2025 due to restrictions under state law (e.g., the rate increases would be tied to the required roll in of several trackers to base rates, but DEV was barred from adjusting base rates to reflect the roll in).

[38] Dominion Energy (2024), "Business review investor slides March 1, 2024", slide 53. Accessed from: https://s2.q4cdn.com/510812146/files/doc_downloads/2024/07/2024-03-01-business-review-investor-slides-vTCI.pdf.

[39] Dominion Energy (2024), "Business review investor slides March 1, 2024", slide 23. Accessed from: https://s2.q4cdn.com/510812146/files/doc_downloads/2024/07/2024-03-01-business-review-investor-slides-vTCI.pdf.

Rate Designs

The utilities' rates are unbundled and there are still separate rates for generation, transmission, and distributor services. Rates for most small-volume customers collect a great deal of revenue using volumetric charges. Both utilities offer time-of-use ("TOU") rates for residential customers.

Certificates of Public Convenience and Necessity

The utilities must obtain certificates of public convenience and necessity ("CPCNs") for the construction, enlargement, or acquisition of any facilities that are not ordinary extensions in the usual course of business.[40] CPCNs can only be issued after opportunity for a hearing and due notice to interested parties. The Commission must consider environmental impacts of generation facilities and related assets and must establish such conditions that "may be desirable or necessary" to minimize adverse impacts. Ratemaking treatment of the cost of certificated projects may be addressed in a CPCN proceeding.

Performance-Based Approaches

Relaxing the Link Between Revenue and System Use

Revenue Decoupling

Revenue decoupling has not been used for DEV or APCo. However, several Virginia gas distributors have decoupling. The customer classes decoupling applies to vary. None of the distributors have revenue decoupling mechanisms that apply to all tariffed rate classes. Revenue decoupling mechanisms for Virginia Natural Gas and Columbia Gas only apply to residential customers.

LRAMs

Previous versions of state statutes permitted DEV and APCo to use LRAMs. To the best of PEG's knowledge no LRAM has been approved in Virginia for an electric utility since 2000.

Metrics and PIMs

State law has occasionally included the opportunity for utilities to present evidence showing that their performance was sufficiently good (or bad) enough to merit an adjustment to its allowed ROE during rate reviews. Adjustments for performance have sometimes taken the form of additions or subtractions to the allowed ROE set in rate reviews. These requests have not often been successful.

Current law permits the utilities' allowed ROE to be adjusted by up to 50 basis points, positive or negative, based on factors that include reliability, generating plant performance, customer service, and the operating efficiency of the utility. Recent legislation has required the Commission to open an investigation on performance incentive mechanisms to determine the appropriate standards and protocols to implement these allowed ROE adjustments. The Commission opened Case No. PUR-2023-

[40] VA. Code Ann. § 56-265.2. 2024

00210 for this purpose and issued its draft scorecard and supplemental reporting metrics in October 2024. Parties filed comments on the draft scorecard and supplemental reporting metrics on November 15, 2024.

Utilities that meet or exceed their energy efficiency savings target each year are allowed to recover a return (set at the company's allowed ROE) on the DSM program operating expenses from that year. If the target is exceeded, the utility is allowed to add 20 basis points to the allowed rate of return for every additional 0.1% in average savings beyond the target, up to a cap that the total amount of incentives cannot exceed 10% of the utility's actual total DSM program spending in that year. Failure to meet the target does not result in any penalty. Appalachian Power exceeded its energy efficiency savings target for 2022 and was allowed to earn a return on its DSM program O&M expenses and a bonus margin.

Targeted Incentives for Underused Practices

Cost Trackers

Tracker treatment is accorded to the cost of some practices that are potentially underused, including EE, demand response, and purchases of energy and capacity from renewable resources. State law currently bans the use of cost tracking to address costs associated with investment in transportation electrification.[41]

Management fees

The current incentive for EE has aspects of a management fee but is treated as a PIM in our discussion above. The utilities may also be awarded a management fee for their EE programs if the programs the Commission approves are insufficient to meet the targets in the EERS (e.g., if the legislatively set targets were set higher than the utilities could reasonably achieve).

Pilot Programs

From time to time, the legislature has authorized pilot programs for the utilities in state statutes. These programs have included energy assistance, energy efficiency, weatherization, community solar (referred to as shared solar), and offshore wind. Pilot programs have also included various residential TOU and EV charging rates and small general service generation TOU rates for DEV.

Multiyear Rate Plans

The extended rate freezes that began around 2015 were technically MRPs but had peculiar features that reduced customer benefits. For example, we noted above that initial rates did not reflect the cost of service.

[41] Va. Code Ann. § 56-585.1:13 2024.

8.3 Business Outlook

Our analysis in Section 3.2 above suggests that the efficacy of traditional ratemaking depends in part on external business conditions. Total demand growth is expected to be brisk for DEV and is likely to require generation capacity expansions. There are notable uncertainties about demand growth, including the progress of beneficial electrification. The trend in the average use of power by DEV's residential customers is still negative. APCo expects slower demand growth than DEV.

On the cost side, the outlook for inflation is uncertain. The bout of macroeconomic inflation that beset the U.S. economy in the last few years has subsided, but the U.S. labor market is tight and the incoming federal government has proposed some policies (e.g., tariffs and mass deportations) that could encourage higher labor prices and bond yields. Electric utility construction cost inflation has been growing rapidly in the South Atlantic region since the COVID-19 pandemic. DEV expects to make extensive capital expenditures to generate more power. Many other capital expenditures will not trigger revenue growth automatically.

On balance, these business conditions point to fairly frequent rate reviews under traditional ratemaking. Rate reviews are in fact being held biennially.

8.4 Desirability of PBR for DEV and APCo

Based on our analyses of ratemaking options and Virginia regulation, we venture the following preliminary comments on the desirability of PBR reforms for DEV and APCo.

Cost Containment Incentives and Regulatory Cost

Under the Company's current ratemaking system, the foreseeable future would involve more biennial (which is to say frequent) rate reviews, an ex post sharing of earnings, and extensive use of cost trackers (called rate adjustment clauses, or RACs, in Virginia). We believe that this system entails unusually weak cost containment incentives and high regulatory cost. High regulatory cost matters at a time like the present, when Virginia faces numerous complicated ratemaking issues beyond ensuring that a utility's year to year rate adjustments reasonably reflect the efficient cost of service.

Multiyear Rate Plans

Well-designed MRPs may produce better results and are an option meriting careful consideration in Virginia's PBR study. These plans can strengthen utility cost containment incentives and streamline ratemaking, as they do in other jurisdictions in the United States and other countries. More time would be available to address other important issues such as rate designs, compensation for DER power surpluses, and integrated grid and delivery system planning.

The current rate review process in Virginia differs from an MRP in important respects. In Virginia, the term is only 2 years, there is earnings sharing, and many costs are tracked. This is an unusual combination that yields unusually weak cost containment incentives and high regulatory cost. It should also be noted that many contemporary MRPs include other provisions that strengthen performance incentives.[42] Examples include revenue decoupling, PIMs for peak load management and DER customer service, and greater use of targeted incentives for underused practices.

A full true up of the revenue requirement to a utility's cost is standard at the outset of an MRP. Our extensive discussion of MRP design options include many that make sense for vertically integrated electric utilities like DEV and APCo. For example, stairstep and hybrid ARMs can reasonably escalate VIEU revenue requirements. Different ARM designs can apply to generation and distributor services. Notwithstanding the potential benefits of MRPs, they need to be designed carefully to ensure that customers share in plan benefits.

In the southeast U.S., we have shown that MRPs are used to regulate VIEUs in North Carolina, Georgia, and Florida. An MRP was also recently used in West Virginia for APCo and Wheeling Power. MRPs have been the favored approach to ratemaking for utilities embracing the energy transition. For example, electric utilities in several states that are leading the energy transition usually have their rates escalated between rate cases with MRPs including those in California, Hawaii, Massachusetts, and New York state. Finally, formula rate plans are an alternative but are not the optimal solution because they provide weak incentives to contain the utilities' cost, and they would likely result in high regulatory cost.[43]

Incentives to Boost Cost-Effective Clean Energy Resources

Weak incentives to boost cost-effective clean energy resources are also a concern in Virginia. Most power consumed in the state is still produced by fossil fuels and the utilities face little financial hardship from the ensuing environmental damage. Incentives to contain energy commodity costs are also weakened by RAC treatment of these costs.

Energy efficiency programs should play a critical role in maintaining reliability and maximizing existing energy resources in Virginia. Maximizing energy efficiency resources is an important focus in evaluating the impact and potential of PBR tools.

Virginia should also consider how PBR tools can be implemented to encourage clean energy and smart technology investments within the state. PBR tools can be used to encourage utilities to pursue solutions that may be innovative but beyond the utility's normal appetite for risk. For example, PIMs can be designed to encourage the utilities to explore new technologies, including DERs and smart grid technologies. These concepts are explored in more detail below.

Revenue Decoupling

Revenue decoupling also merits serious consideration in the PBR study, as most of the reasons that decoupling is adopted in other jurisdictions exist in Virginia.

[42] See, for example, the current MRPs for Consolidated Edison and NSTAR Gas. Brief summaries of these plans are provided in Appendix 2.

[43] See, for example, the recent formula rate plan proceedings for Baltimore Gas & Electric and Potomac Electric Power as well as the related "Lessons Learned" proceeding in the state of Maryland.

- Virginia's energy costs are projected to rise significantly in the coming years, due in large measure to capacity expansions. Decoupling eliminates the utility's throughput incentive to boost energy sales, thereby removing the utility's incentive to resist cost saving measures like energy-efficiency programs as well as cheaper third-party and customer-owned distributed generation.
- The environmental damage from generating and delivering power from fossil fuels is largely external to the utilities, and the cost of purchasing power and generation fuels is tracked.
- Virginia's current regulatory system also does little to encourage utilities to contain capex costs. Instead, their incentive to avoid excessive capacity expansion and other kinds of capex is weakened by frequent rate reviews, RACs for new generation costs, and formula rates for power transmission that turn capex into earnings opportunities. Regulators in other jurisdictions have found it desirable to supplement targeted utility incentives to embrace DSM and DERs with revenue decoupling.
- In an era of imminent capacity expansion, there is presently a great need for innovative rate designs that discourage inefficient peak load growth. For example, decoupling can encourage pervasive use of time-sensitive rates by reducing the risk of recovering some of the cost of base rate inputs in the peak-period charge.
- Under a decoupling mechanism, utilities enjoy reduced risk, which allows policy makers and regulators to request programs and utility offerings that maximize energy efficiency and peak load management savings.

If decoupling is adopted, consideration should be paid to excluding some loads or according them a partial decoupling treatment. Loads that may merit special treatment include those for beneficial electrification and possibly also those of price-sensitive industrial customers.

Targeted Incentives

Metrics and PIMs

We noted above that the Commission is considering standards and protocols on performance metrics and PIMs in another proceeding. Comments have already been filed by Clean Virginia and other parties. Here are some PEG comments on the matter.

- In general, Virginia could benefit from the development of metrics and PIMs to measure and incentivize utility performance in targeted areas. The development of good tools is challenging and will take some time and effort.
- The SCC has carefully developed a draft scorecard, metrics, and PIMs that reflect the comments of diverse parties.
- Our analysis suggests that a PIM is needed for DER customer service quality. A PIM for peak load management also merits consideration. PIMs for beneficial electrification are used in some jurisdictions where decoupling applies to these loads.
- Greater use of statistical benchmarking should be considered. Alternatives to simple unit cost and average rate metrics such as econometric cost modelling show promise and are used in

several North American jurisdictions. Econometric cost models have been developed to appraise VIEU costs and its major components. Benchmarking is also feasible for reliability metrics such as “blue sky” SAIDI and SAIFI. Benchmarking is facilitated in the U.S. by the availability of many years of detailed data on the operations of U.S. electric utilities.

- Benchmarking can be used to establish stretch factors outside of the 50 basis point incentive allowance. These stretch factors are most frequently used with indexed ARMs but can also be used with other ARM designs. With or without an MRP, benchmarking can also be used to appraise forecasted/proposed costs in rate reviews as well as historical costs.

Targeted Incentives for Underused Practices

Targeted incentives for underused practices are already used in Virginia in the form of cost tracking for EE programs. Thought should be paid to expanding the role of these incentives going forward. Options for encouraging other underused practices include RACs for the costs of these practices, management fees, and pilot programs.

Management fees are a possible alternative to PIMs for encouraging peak load management. Another area where targeted incentives for underused practices could be applied is the accommodation of DERs. Utilities are slow to embrace DERs because they can slow revenue growth while occasioning costs to accommodate them. DERs can trim the need for new generating capacity and help with clean energy goals. The cost of DER accommodation is explicitly tracked in California. Tracking costs of accommodating beneficial electrification also merits consideration if decoupling applies to these services.

Role of Cost Trackers

Cost trackers are a useful tool in electric utility ratemaking but should be used cautiously. Like measures to stimulate the macro economy during a recession, it is possible to use “too much of a good thing”. We believe that too much of the utilities’ capex is currently accorded tracker treatment. Target ROEs may merit downward adjustment if this controversial approach continues. There is an art to limiting the use of trackers chiefly to areas where cost is especially large and volatile, uncertain, or the use of the associated inputs requires encouragement.

Stakeholder Process

One common characteristic of well-designed PBR studies in other states is a robust, collaborative stakeholder process. Virginia’s stakeholder process should incorporate best practices from model states, including Connecticut, Hawaii, Minnesota, and Nevada. These states have benefited from an intentional effort to engage and inform a broad collection of stakeholders over many months. In Connecticut, for example, regulators have implemented a multi-phase process lasting several years, including formal information requests, several written comment periods, topic-targeted stakeholder workshops, public listening sessions, and opportunities for feedback on draft proposals.[44] In Hawaii, regulators facilitated a stakeholder process lasting more than two years, which ultimately resulted in a comprehensive regulatory framework with multiyear rate plans, performance incentives, and innovative energy pilots.[45] Some states, such as Indiana, have opted to engage an independent consultant to facilitate their months-long processes.[46]

[44] State of Connecticut Public Utility Regulatory Authority, Docket No. 21-05-15, PURA Investigation into a Performance-based Regulation Framework for the Electric Distribution Companies: Decision (April 26, 2023), at 5-9, available at https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/cb38ec58b74562198525899d004c2021/$FILE/210515-042623.pdf

[45] Relf, Grace. "Strategies for Developing Effective Performance Incentive Mechanisms (Hawaii)" NARUC. October 2022; State of Hawaii Public Utilities Commission, Summary of Phase 2 Decision & Order Establishing a PBR Framework (December 23, 2020), https://puc.hawaii.go -content/uploads/2020/12/PBR-Phase-2-DO-5-Page-Summary.Final .12-22-2020.pdf

[46] Indiana Utility Regulatory Commission, Performance-Based Ratemaking Study, https://www.in.gov/iurc/performance-based-ratemaking-study/

Appendix

A.1 Glossary of Terms

Advanced Metering Infrastructure ("AMI"): An integrated system of smart meters, communications networks, and data management systems that enables two-way communication between the electric company and customers.

Alternative Regulation ("Altreg"): Alternatives to traditional cost of service ratemaking. These include formula rates, forward test years, and various kinds of PBR.

Attrition Relief Mechanism ("ARM"): A key component of multiyear rate plans which uses a predetermined formula to adjust utility rates between general rate reviews without closely tracking the growth of all of the company's *own* costs. Methods used to design ARMs include forecasts and indexation to quantifiable external cost drivers such as inflation and customer growth.

Base Rates: The components of an electric company's rates which provide compensation for costs of non-energy inputs such as labor, materials, services, and capital.

Beneficial Electrification: Replacement of fossil-fueled equipment such as motor vehicles and space heaters with alternative equipment that is powered by electricity.

Capex: Capital expenditures.

Cost of Service Ratemaking ("COSR"): The traditional North American approach to ratemaking which resets base rates in irregularly timed rate cases to reflect the cost of service that regulators deem prudent.

Cost Tracker: A mechanism providing expedited recovery between rate cases of targeted costs that are deemed prudent by regulators. A tracker is an account of costs that are eligible for recovery. Costs deemed prudent can be recovered promptly with a rate surcharge (aka "rider") or deferred as "regulatory assets" for future recovery. Tracker treatment was traditionally limited to costs that are large, volatile, and largely beyond the control of the electric company. In more recent years, trackers have been used to address rapidly rising costs and costs of underused practices.

Demand-Side Management ("DSM"): Energy conservation, peak load management, and other activities intended to reduce the use of a utility system.

Distributed Energy Resources ("DERs"): Technologies, services, and practices that can improve efficiency or generate, manage, or store energy on the customer side of the meter. DERs include distributed generation, energy management systems, and batteries.

Earnings Sharing Mechanism ("ESM"): Automatically shares surplus or deficit earnings (or both) between utilities and customers which result when the rate of return on equity deviates materially from its commission-approved target. ESMs often have dead bands in which earnings variances are not shared.

Energy Transition: The transition of the economy to greater reliance on electricity that is generated from clean resources. This transition is likely to entail brisk demand growth and a need for a more resilient grid.

Federal Energy Regulatory Commission ("FERC"): The federal agency responsible for regulating rates for utility services offered in interstate commerce. These services include power transmission, bulk power supply, and interstate gas pipeline transportation and storage.

Formula Rate Plan ("FRP"): A formula rate plan is designed to make a company's revenue closely track its own cost of service. It typically entails a mechanism for truing up a utility's revenue to the portion of its actual costs that regulators deem prudent. Formula rates are widely used by the FERC in power transmission regulation.

Multiyear Rate Plan ("MRP"): A common approach to PBR that typically features a multiyear moratorium on general rate reviews, an attrition relief mechanism, and several PIMs. Regulatory schemes in some states are *called* MRPs but act more like formula rates due to fine-print "reconciliation mechanisms" (e.g., DC, IL, MD).

Opex: Operation and maintenance ("O&M") expenses. For electric utilities filing the FERC Form 1, these expenses are reported on pages 320-323.

Performance-Based Ratemaking ("PBR"): An approach to ratemaking designed to strengthen utility performance incentives. Some PBR approaches also streamline ratemaking.

Performance Incentive Mechanism ("PIM"): A mechanism consisting of one or more metrics, targets, and financial incentives (rewards and/or penalties) that is designed to strengthen performance incentives in a targeted area such as reliability or energy efficiency.

Performance Metric: A specific measure intended to shed light on a utility's performance. Some examples of performance metrics include cost per customer, the system average interruption duration index, and annual energy efficiency savings.

Pilot Program: An experimental initiative undertaken by a utility in an attempt to increase its efficiency or provide additional and/or improved services to customers. Pilot programs may include tests of new technologies or revised processes.

Productivity: The ratio of outputs to inputs is a rough measure of operating efficiency that controls for impact of input prices and operating scale on cost. Multifactor productivity is the productivity of multiple inputs (e.g., capital, operation, and maintenance inputs).

Rate Case: A proceeding to reset an electric company's base revenue requirement to better reflect the cost of service. These proceedings may also consider other issues such as rate designs.

Rate Case Moratorium: A set period of time without general rate cases.

Rate of Return on Equity ("ROE"): The rate of return on the value of equity capital invested. The target ROE is a prominent issue in rate cases.

Rate Rider: A mechanism, frequently outlined on tariff sheets, which allows an electric company to receive rate adjustments between rate cases.

Revenue Adjustment Mechanism ("RAM"): A mechanism for escalating allowed revenue automatically between rate cases which is commonly used in conjunction with revenue decoupling.

Revenue Cap Index: A formula sometimes used for escalating allowed revenue in MRPs which typically includes an inflation index and an X factor.

Revenue Decoupling: A mechanism for relaxing the link between an electric company's revenue and use of its system, which makes periodic rate adjustments to ensure that actual revenue closely tracks allowed revenue between rate reviews. A companion revenue adjustment mechanism typically escalates allowed revenue between rate reviews for a key cost driver such as customer growth.

Revenue Requirement: The annual revenue that the electric company is entitled to collect as compensation for the cost of service. The amount is periodically recalculated in rate reviews to reflect costs and may be escalated by other mechanisms (e.g., cost trackers and ARMs) between rate reviews. The corresponding cost is typically the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base less other operating revenues.

RIIO: An approach to energy utility ratemaking used by Great Britain's Office of Gas and Electricity Markets ("Ofgem") that combines revenue decoupling, targeted incentives for underused practices, multiyear rate plans, and various metrics and targeted performance incentive mechanisms. The term RIIO stands for Revenue = Incentives + Innovation + Outputs.

Scorecard: A summary of a utility's performance on various metrics in a performance metric system. This summary is often reported on a publicly available website.

Stretch Factor (aka Consumer Dividend): A term in an index-based ARM or RAM formula that reflects the customer's share of the expected benefit of increased cost containment incentives from an approved MRP.

Targeted Incentives for Underused Practices: Direct incentives for utilities to embrace practices that they tend to underuse because they are novel, save tracked or external costs, or reduce capex. DSM is a classic example. Incentives that have been used to encourage underused practices include tracker treatment for their costs, capitalization of their costs (if O&M expenses), management fees, and pilot programs.

Test Year: A specific period in which an electric company's costs and billing determinants are considered in a rate review. Some states use a historical test year and adjust billing determinants and costs for known and measurable changes. Other states use a fully forecasted test year that considers other possible changes.

X-Factor (aka Productivity Factor): A term in an indexed ARM formula which reflects the typical impact of productivity growth on cost growth. The X factor may also incorporate a stretch factor and an adjustment for the inaccuracy of the inflation measure that is used in the ARM formula.

Z-factor: A term in an indexed ARM formula that adjusts rates or revenues for the earnings impact of miscellaneous, hard-to-foresee external events (e.g., severe storms, tax rates).

A.2 Case Studies of Multiyear Rate Plans

Consolidated Edison of New York

Plan Term: 3 years beginning January 2023

Predetermined Base Revenue "Stair Steps":	2023	2024	2025
Capex underspends trued up at end of plan	6.6%	6.2%	5.8%

Earnings Sharing: Overearnings only

Revenue Decoupling: Most services

PIMs

- Reliability & customer services
- Energy efficiency
- Policy PIMs called "earnings adjustment mechanisms" encourage non-wires alternatives, reductions in peak load, distributed solar generation, distributed storage, beneficial electrification, and managed EV charging

Reference: New York Public Service Commission Case 22-E-0064

Florida Power & Light

Plan term: 2022-2025 (4 years)

Cost Trackers

- Fuel & purchased power
- Solar generation capex
- Storm cost recovery
- Storm protection plan
- DSM
- Environmental compliance capex
- Permanent federal or state tax changes

No Decoupling >>> Revenue rises with load growth

Reference: Florida Public Service Commission Docket No. 20210015-EI

NSTAR Gas (Massachusetts)

Plan term: 10 years

Indexed ARM

$$Base\ Revenue_t = Base\ Revenue_{t-1} * (1+ Inflation - X - Consumer\ Dividend +/- Z)$$

$$Inflation = growth\ GDPPI$$

X = -1.18%

Consumer Dividend: 0.15%

PIMs for DSM, gas safety response time, customer service quality

Revenue Decoupling

Geothermal Network Demonstration Project

Trackers for various costs including DSM, pensions and other post-retirement benefits, gas safety capital net of O&M cost savings, geothermal network demonstration project

Reference: Massachusetts Department of Public Utilities 19-120

Southern California Edison

Plan Term: 3 years beginning January 2021

Hybrid ARM

- O&M revenue escalated using utility input price indexes
- Most capital additions in out years (except new service connections) equal test year additions
- Wildfire capital additions determined by forecast

Revenue Decoupling

Cost Trackers for DSM, wildfire risk mitigation, microgrids, DER accommodation, electric vehicles, and replacement of poles and underground structures in poor condition

Other Provisions: Wildfire mitigation plans, microgrid incentive program

Reference: California Public Utilities Commission Decision 21-08-036

Xcel Energy- Minnesota

Plan term: 3 years, 2022-2024

Predetermined Base Revenue "Stair Steps":	2022	2023	2024
Any capital cost savings refunded	4.84%	8.69%	14.06%

Revenue Decoupling

Cost Trackers

- Fuel & purchased power
- DSM expenses
- Renewable generation costs
- Environmental compliance costs

PIMs for DSM, reliability, and customer service quality

Advanced Rate Design docket to be opened

Reference: Minnesota Public Utilities Commission Docket No. E-002/GR-21-630

Alberta Energy Distributors (PBR3 Rate Plan)

Application: Base rates (less pensions & benefits)

Attrition Relief Mechanism: Escalation provided by growth Inflation-X+Y+Z

- Price caps for power distributors, revenue/customer caps for gas distributors
- Custom inflation measure averages Alberta CPI & wage rate inflation
- X factor of 0.1% informed by research on U.S. power distributor productivity
- 0.3% stretch factor called "X factor premium"
- K-bar replaces indexed capital revenue with revenue based on each company's historical capex
- Capital cost tracker for extraordinary projects required by 3rd parties including capex directly caused by laws related to net-zero objectives

Plan term: 5 years (2024-2028)

Earnings Sharing Mechanism: Overearnings only

Reference: Alberta Utilities Commission Decision 27388-D01-2023

A.3 PEG Credentials

PEG is an economic consulting firm headquartered on Capitol Square in Madison, Wisconsin. We are the leading North American consultancy on PBR and statistical research on energy utility cost and cost performance. Our personnel have over eighty years of experience in these fields, which share a common foundation in economic statistics. We have for many years monitored the progress of PBR, preparing surveys and white papers on various plan design topics. Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given PEG an unusual reputation for objective empirical research and commitment to good regulation. We have had a notable impact on the evolution of PBR in the United States and Canada.

Mark Newton Lowry, lead author of this report, is the President of PEG. He has over forty years of experience as an applied economist, most of which have been spent addressing energy utility issues. Author of dozens of professional publications, he has also spoken at numerous conferences on utility regulation and statistical performance measurement. He coauthored two influential white papers on PBR for Lawrence Berkeley National Laboratory. A long-time advisor and expert witness on PBR to the Ontario Energy Board, he has in the last eight years alone testified or provided commentary in PBR proceedings in Colorado, Connecticut, Hawaii, Massachusetts, Minnesota, North Carolina, Virginia, Washington, Alberta, British Columbia, and Québec. Native to Northeast Ohio, he holds a PhD in applied economics from the University of Wisconsin and lives in Shorewood Hills, Wisconsin, near Madison.

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