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# Design Considerations for a Multi-Year Rate Plan Framework in Virginia

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Clean Virginia

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# 1. INTRODUCTION

House Joint Resolution No. 30 and Senate Joint Resolution No. 47 directed the State Corporation Commission (Commission) in collaboration with the Virginia Department of Energy (Virginia Energy) to study performance-based regulatory tools for investor-owned electric utilities (the “SCC Study”). The goal of the SCC Study is to evaluate the potential for performance-based regulation and alternative regulatory tools to assist with:

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

Clean Virginia retained Synapse Energy Economics, Inc. (Synapse) to support the goals of the SCC Study by providing an assessment of Virginia’s current regulatory framework and the potential for a multiyear rate plan (MRP) to help support improved regulatory outcomes. This report includes an overview of the potential benefits and risks of MRPs and design recommendations for an MRP framework in Virginia to ensure that both ratepayers and utilities can benefit from an alternative regulatory structure.

# 2. OVERVIEW OF CURRENT REGULATORY FRAMEWORK

The current regulatory framework for Dominion Energy Virginia (Dominion) and Appalachian Power Company (APCo) is not optimal to create utility incentives for cost-containment or to support demand-side resources such as energy efficiency and distributed energy generation. As shown in Table 1, frequent rate cases, earnings test design, and the widespread use of trackers all have the potential to create negative outcomes for Virginia’s ratepayers and the environment.



**Table 1. Virginia regulatory framework and resulting utility incentives**

<b>Regulatory Element</b>	<b>Virginia Regulatory Framework</b>	<b>Utility Incentive</b>
Frequency of rate cases	Every two years per the Virginia Electric Utility Regulation Act	Two-year rate case cadence results in limited regulatory lag.
Base rate adjustments between rate cases	None	Creates incentive to increase sales (throughput incentive) and oppose load-reducing measures (energy efficiency, distributed generation).
Test year	Forward looking	Developing rates based on unknown future costs creates a risk that those costs may be inflated, resulting in overcompensating the utility.
Earnings Sharing Mechanism	Earnings test measures earnings of utility over a 13-month historical period; overearnings shared with customers (Dominion) or fully credited above 100 basis point deadband (APCo)	<p>The 100 basis point deadband for APCo offers some cost-containment incentives as it retains all earnings below deadband.</p> <p>Dominion’s earnings test lacks a deadband which weakens cost-containment incentives.</p> <p>The two-year rate period dampens any cost-control signal from an earnings test due to short period of time before rates are reset.</p>
Trackers	Widespread use of trackers	Cost trackers erode cost-control incentive by reconciling revenues to actual costs each year.

The remaining sections of this report will examine the potential benefits and risks of MRPs and how the implementation of a well-designed MRP could improve upon the existing regulatory framework by better aligning utility incentives with ratepayer interests and energy policy goals.

## **3. POTENTIAL BENEFITS AND DRAWBACKS OF MRPs IN VIRGINIA**

### **3.1. Overview of the potential benefits and risks of MRPs**

#### **Benefits**

MRPs have the potential to provide a range of benefits for both utilities and customers. When designed well, MRPs can encourage utilities to reduce spending and find cost efficiencies, while providing utilities with additional revenue between rate cases and reducing administrative burden.

One way of measuring the overall benefits of MRPs is to examine the relative productivity growth of utilities with MRPs to those operating under traditional cost-of-service regulation. The Pacific Economics Group developed a model to assess the change in multifactor productivity growth over time for several MRPs across the United States and Canada. Multifactor productivity is a measurement of the relative amount of output for each unit of all combined inputs.<sup>1</sup> The model found that utility long-run cost performance on average improved 0.51 percent more rapidly each year in an MRP with a five-year term and no earnings sharing than it did under traditional regulation when rate cases occurred every three years.<sup>2</sup>

One example of an MRP creating improvements in cost efficiency can be found in Alberta. Alberta power distributors were subject to cost-of service regulation with two-year rate cases until 2013, a price cap index until 2017, and a price cap index with a supplemental capital mechanism until 2023. The analysis found that multifactor productivity growth was highest during the price cap index periods relative to the cost-of-service periods. This was largely driven by growth in operation and maintenance (O&M) productivity growth, as capital productivity growth decreased during the price cap periods.<sup>3</sup> These productivity trends demonstrated that MRPs “can materially slow utility cost growth by strengthening incentives.”<sup>4</sup>

## Risks

Despite the many potential benefits offered by MRPs, they can also present risks, particularly if not designed well. Poorly designed MRPs can allow utilities to recover costs more quickly without increasing benefits to customers or advancing energy policy goals; reduce regulatory lag with no commensurate strengthening of cost-containment incentives; exploit information asymmetries, particularly through reliance on cost forecasts; and shift risks to ratepayers if the commission pre-approves investments and costs.

One prominent example comes from Maryland where the performance of Baltimore Gas and Electric’s (BGE) and Pepco MRPs are currently under review.<sup>5</sup> The current MRP framework includes the use of utility-specific cost forecasts to set the MRP revenue requirement and a reconciliation process during and after-MRP period. The reconciliation process permits utilities to recover costs that exceed forecasts

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<sup>1</sup> Bureau of Labor Statistics, Productivity 101, U.S. Bureau of Labor Statistics website: <https://www.bls.gov/k12/productivity-101/content/what-is-productivity/what-is-multifactor-productivity.htm#:~:text=Multifactor%20productivity%20%28MFP%29%20is%20a%20measure%20of%20economic,incl%20labor%2C%20capital%2C%20energy%2C%20materials%2C%20and%20purchased%20services.>

<sup>2</sup> Lowry, Mark N. et al. 2017. “State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities.” Lawrence Berkeley National Laboratory.

<sup>3</sup> Lowry, Mark N., David A. Hovde, Rebecca Kavan, Matthew Makos. 2023. “Impact of multiyear rate plans on power distributor productivity: Evidence from Alberta.” *The Electricity Journal*, Volume 36, Issue 5, pg. 5. 107288, ISSN 1040-6190, <https://doi.org/10.1016/j.tej.2023.107288>.

<sup>4</sup> *Id.*, pg. 7

<sup>5</sup> Public Service Commission of Maryland (MD PSC), Case No. 9618.

over the MRP term, less carrying costs, contingent upon regulatory review and return any under-spend to ratepayers. Stakeholders in Maryland have argued that the MRP design encourages utilities to increase capital spending, increases regulatory burden, reduces transparency on benefits and costs, and shifts risk onto customers, who may face substantial rate increases with minimal quantifiable benefits.

For example, the Maryland Energy Administration (MEA) argued that because utilities are no longer held to historical test-year costs, utilities can increase forecasted costs and overspend without limits. MEA cited evidence that BGE's average 2023 MRP reconciliation variance was 115 percent for electric capital expenditures and 177 percent for O&M.<sup>6</sup> Furthermore, MEA also states that under MRPs, utilities can recover overspending through riders in a less thorough review process.<sup>7</sup>

The Maryland Office of People's Counsel (OPC) presented a similar argument, claiming that MRPs are not in the public interest and have resulted in significant rate increases. OPC cites O&M and capital expenditures that exceeded the amount authorized by the Commission. For instance, BGE overspent on capital expenditures by 25 percent in 2022 and 44.9 percent in 2023.<sup>8</sup> Additionally, the reconciliation mechanism allowed BGE and Pepco to seek recovery of more than \$268 million above the authorized revenue requirement.<sup>9</sup> Table 2 shows the cumulative MRP revenue requirement, comparing the amounts awarded and the actual figures for BGE and Pepco over three years. OPC further points out that BGE and Pepco did not quantitatively demonstrate how customers have benefited from the increased capital spending and did not identify any improvements in service quality.

**Table 2. Cumulative MRP revenue requirement: awarded and actual (\$ millions)**

	Rate Year 1		Rate Year 2		Rate Year 3	
	Awarded	Actual	Awarded	Actual	Awarded	Actual
BGE Electric	\$59.30	\$71.90	\$98.00	\$137.00	\$139.90	\$218.88
BGE Gas	\$53.24	\$60.51	\$64.01	\$78.52	\$73.88	\$147.21
Pepco	\$20.64	\$21.70	\$36.90	\$45.24	\$52.24	\$91.78

*Source: Public Service Commission of Maryland Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company, Brief of the Maryland Office of Peoples Counsel, Table 1, pg. 17.*

The Maryland example demonstrates how a poorly designed MRP can create risks to customers. Virginia can avoid these problems by not permitting reconciliation of overspend during or after the MRP. In

<sup>6</sup> MD PSC Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company, *Comments of the Maryland Energy Administration on Multi-Year Rate Plan*, pg. 2.

<sup>7</sup> *Id.*, pg. 3

<sup>8</sup> MD PSC Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company, *Reply Comments of the Maryland Office of Peoples Counsel*, pg. 13.

<sup>9</sup> *Id.*, pg. 15.

addition, allowing utilities to benefit from reducing spending below budgets can provide utilities with an incentive to seek cost-efficiency.

### 3.2. MRP design choices for Virginia

There are five key design choices to consider when developing an MRP framework. As shown in Table 3, each MRP design element choice has an impact on utility incentives.

**Table 3. MRP design choices and impact on utility incentives**

<b>MRP Design Element</b>	<b>Impact on Utility Incentives</b>
1. Revenue requirement included in MRP (e.g., limited to O&M spending or also including capital costs, Rate Adjustment Clauses)	More costs in MRP = stronger cost-containment incentive
2. Attrition Relief Mechanism (how revenues are adjusted during MRP)	External cost indexes = stronger cost-containment incentive
3. Reconciliation of revenues to actual costs	Reconciliation removes cost-containment incentive
4. Earnings Sharing Mechanism (ESM)	Allowing the utility to keep all earnings above its authorized ROE provides a strong incentive for the utility to control costs; however, this creates risks to ratepayers. An ESM helps to balance the benefits and risks between the utility and its customers.
5. MRP stay-out period	Longer stay-out period = stronger cost-containment incentive

This section of the report will provide an overview of each MRP element and discuss potential design choices for Virginia. In addition, though not required as part of an MRP, this section will also review the potential for a decoupling mechanism to improve the current regulatory framework.

#### Revenue requirements included in the MRP

##### ***Recovery of revenues***

An initial design consideration for Virginia is to determine what utility costs to include in the MRP revenue requirements. Currently, approximately 50 percent of Dominion’s and APCo’s revenues are recovered through Rate Adjustment Clauses (RAC) or “trackers.” Costs recovered through RACs are recovered on a dollar-for-dollar basis. Some of the trackers, including the costs of demand response programs, broadband capacity extensions, lost revenues from low-income customer discounts, and renewable portfolio standard (RPS) costs are commonly seen in other jurisdictions. For example, New York has reconciliation accounting mechanisms for Regional Greenhouse Gas Initiative costs, system

benefits charges for efficiency programs, market supply charges, and costs associated with the low-income customer charge discounts.<sup>10</sup>

However, Dominion also has trackers for a substantial amount of capital projects including for two gas-fired combined-cycle plants, offshore wind, solar generation, distribution undergrounding, distribution “grid transformation,” and service life extension for nuclear generating units. Dominion also forecasts that approximately 75 percent of its forecasted capital plan will be eligible for tracker treatment.<sup>11</sup>

The potential benefits of an MRP will be diluted if half or more of a utility’s revenue requirement is recovered outside of base rates through trackers or riders. Cost trackers erode a utility’s incentive to control costs because the utility is allowed to reconcile revenues to actual costs each year. There is therefore no incentive for the utility to control its costs or seek cost-efficiencies.

Tracking mechanisms are appropriate only for a very limited set of costs that are outside of a utility’s control. For example, costs such as taxes, pensions, and market supply costs are sometimes passed through via a tracker. In addition, one-time, reasonably incurred extraordinary costs (such as extraordinary storm response costs) could be recovered through a tracker.

An MRP can only support cost-containment incentives for costs contained within the MRP’s revenue requirement cap. Having a large number of RACs essentially shifts Virginia’s regulatory framework more towards a formula rate plan, which is the antithesis of an MRP. Formula rate plans allow for a utility to true up revenues to actual costs. This shifts financial risks to customers and reduces incentives for utilities to control costs.

Formula rate plans have been shown to create negative outcomes for customers in other jurisdictions. For example, in Arkansas, Entergy had a formula rate plan with annual rate true-ups capped at 4 percent each year. The Arkansas commission staff found that the formula rate plan incentivized spending and created an outcome of a 4 percent increase each year (over the prior year). Staff further concluded that the unstated implication of the formula rate plan is that the risk of an earnings review is effectively eliminated.<sup>12</sup> The Maryland Public Service Commission also noted that problems with formula rate plans include “tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs.”<sup>13</sup>

### ***Recommendations for Virginia***

If Virginia decides to move forward with the development of an MRP framework, it is imperative that trackers—recurring pass-through or mandated costs such as RPS or pensions; or one-time extraordinary

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<sup>10</sup> New York Public Service Commission, Case 13-E-0030.

<sup>11</sup> Lowry, M.N., Makos, M., and Kavan, R. 2024. *Performance-Based Regulation Basic Features and Possible Applications to Virginia’s Electric Utilities*, prepared for Clean Virginia by Pacific Economics Group Research, LLC, pg.44.

<sup>12</sup> AR PSC Staff, Initial Brief Pursuant to Order No. 18, Docket 16-036-FR, January 1, 2019.

<sup>13</sup> Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53.



costs—are included in the MRP’s revenue requirement to help rebalance risk across utility customers and shareholders.

There are several examples of utilities including capital projects, including those related to generation plants, within an MRP. For example, Florida Power & Light (FPL) recovers costs associated with solar and battery generation installations within its MRP.<sup>14</sup> Pacific Gas and Electric Company (PG&E) includes capital-related costs associated with natural gas and solar capital expenditures in its MRP.<sup>15</sup> In addition, Duke Progress NC has “MYRP Projects” covering generation, energy storage, and distribution among other areas included in the MRP revenue requirement.<sup>16</sup>

The next design element covered in the following section will examine different methods for how costs currently recovered through trackers should be forecasted over the MRP period.

## **Attrition relief mechanism**

### ***Overview***

Attrition relief mechanisms (ARM) escalate a utility’s allowed revenues over the course of an MRP. The ARM can be based on either an external price index or a cost forecast. With cost forecasts, information asymmetry is a serious concern, which has led many jurisdictions to opt for an index-based approach.

### **Cost forecasts**

An ARM based on forecasts increases revenue by predetermined percentages in each plan-year based, at least in part, on a utility’s cost projections. The percentages can be different in each year, or the total increase can be leveled across the years.

To determine the revenue requirement for each year, the ARM must account for both older capital investments (i.e., depreciation expenses) and new capital additions. Depreciation expenses are straight-forward to calculate, as older capital simply continues to depreciate.

ARMs based on cost forecasts enable the utility’s revenues to accommodate unusual investment trajectories, such as a capital investment surge. Since the ARM generally operates as a cap on revenues, it provides an incentive for the utility to ensure that actual investment costs are kept under the cost cap. This is a benefit over the use of cost trackers. However, the use of a utility-specific cost forecast exacerbates information asymmetries since the utility will always have the most technical knowledge and information regarding its systems. This creates challenges for the intervening parties and regulators

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<sup>14</sup> Oliver T., Florida Power and Light Company Direct Testimony of Tim Oliver, Docket 20250011-EL, February 28, 2025, at 20-21.

<sup>15</sup> Reynolds J., Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company, Application 21-06-021, November 16, 2023, at 707-709 and 713-715.

<sup>16</sup> Taylor, K., Direct Testimony of Kathryn S. Taylor for Duke Energy Progress, LLC, Docket No. E-2, Sub 1300, October 6, 2022, Exhibit 1, at 5-11.

in ensuring that cost forecasts are reasonable, as it is difficult to ascertain if forecasts are reasonable without sufficient information. The National Regulatory Research Institute describes this issue as follows:

Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains that leaves unknown the utility's level of managerial competence embedded in the forecast.<sup>17</sup>

The extreme difficulty of ensuring the accuracy of a utility's cost forecasts places customers at risk that the allowed MRP revenues will be set too high. Because regulators and any intervening parties can never completely vet the accuracy of cost forecasts, utilities have an inherent bias to overstate their costs and understate revenues. When a utility's rate of return is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This is often referred to as the Averch-Johnson effect.<sup>18</sup>

There are ways to help mitigate these risks within an MRP. For example, in addition to the current integrated resource plans, utilities could file integrated distribution plans that would allow interested parties to review the assumptions, forecasts, and planned investments prior to such project costs showing up in the MRP. Other options include having the regulator conduct independent benchmarking and engineering studies to determine the reasonableness of cost forecasts or check the accuracy of past cost forecasts and create performance incentive mechanisms (PIM) for forecasting accuracy.

#### Index-based approaches

External indexes have historically been the preferred means by which to set a utility's allowed revenue requirements for future years of an MRP. In some cases, MRPs escalate different categories of costs at different rates based on separate cost indexes. For example, IHS Global Insights provides cost-escalation forecasts that are specific to the utility industry and are broken out by category of cost.

Indexes may be coupled with a "productivity factor." This productivity factor is often denoted as "X" and generally reflects the multifactor productivity of a group of peer utilities. In addition, a stretch factor (or

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<sup>17</sup> Costello, K. 2016. Multiyear Rate Plans and the Public Interest, National Regulatory Research Institute, pages 35–36.

<sup>18</sup> Economists identify the Averch-Johnson effect as the tendency of regulated companies to engage in excess capital investments to increase their profits, as originally published in the *American Economic Review*, vol. 52, no. 5, 1962, at 1052–1069 "Behavior of the Firm Under Regulatory Constraint" by Harvey Averch and Leland L. Johnson.

“consumer dividend”) may be added to the productivity factor in order to provide customers with a share of the benefit of the stronger performance incentives expected under the plan.<sup>19</sup>

Escalating allowed revenues based on an external index permits the utility to continue making necessary investments and avoid revenue attrition, while avoiding concerns regarding strategic behavior (i.e., gaming of forecasts) and information asymmetry that are present in forecast-based ARMs.

#### Hybrid approach

Not all costs categories within an MRP need to be escalated in the same way. Some MRPs have O&M costs escalated using an external index and capital costs escalated using a utility-specific forecast. For example, Southern California Edison (SCE) escalated non-labor O&M based on an IHS Global Insight index. On the other hand, capital-related costs are escalated based on a composite rate developed from IHS Global Insight forecasts of the Handy-Whitman Index and a utility-specific index based on recorded General Plant costs for recent years as recorded in SCE’s FERC Form 1. Those escalation rates are then averaged for the plan term and applied to test-year capital additions.<sup>20</sup>

#### ***Recommendations for Virginia***

It may be reasonable for the costs contained in the biennial rate review to be escalated using the index approach. However, Virginia is currently experiencing large increases in load, particularly from data centers. Because of this, traditional index-based revenue escalation methods may not provide sufficient revenues for utilities.

Specific to RACs, the utilities already have revenue requirement forecasts associated with the project costs being recovered through these trackers. Therefore, the forecasted revenue needs associated with the projects included in RACs can inform development of the MRP revenue requirement. Planned new capital plant additions not currently being recovered through RACs could be forecasted in the same manner. As indicated above, FPL, PG&E, and Duke Progress NC use company-specific cost forecasts for capital generation costs within MRPs.

As indicated above, determining MRP revenues based on utility cost forecasts shifts risk to customers. To address this risk we recommend that Virginia utilities conduct transparent, integrated planning at the generation, transmission, and distribution levels, provided this planning exercise results in thorough evaluation of all resources (including non-wires alternatives) and a clear investment plan.

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<sup>19</sup> Lowry, Mark N. et al. 2017. “State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities.” Lawrence Berkeley National Laboratory , 4.2, <https://escholarship.org/uc/item/4r13j347>.

<sup>20</sup> Southern California Edison (U 338-E) 2018 General Rate Case Application 16-09-001 (SCE-09, Vol. 1) at 85.

## Reconciliation

### Overview

Allowing a utility to reconcile spending in excess of the allowed MRP revenue requirement undermines any cost-containment incentive. When reconciliations are used, the MRP resembles more of a broad-based cost tracker and loses its ability to encourage cost efficiencies.

However, some jurisdictions utilize one-way (downward) reconciliations when utility-cost forecasts are used to protect customers from the risk that utilities have overstated the cost forecast.<sup>21</sup> For example, Con Edison's three-year MRP includes a "Net Plant Reconciliation Mechanism" or "claw-back mechanism." A downward-only reconciliation is required if Con Edison's actual expenditures for electric and gas capital programs and projects result in actual net that is less than the amount originally forecasted in the MRP filing. The company will defer the carrying costs associated with the difference for the benefit of ratepayers.<sup>22</sup> A one-way reconciliation mechanism reduces the benefit that the utility receives from inflating its cost projections and protects customers from utility under-spend. The one-way nature of the reconciliation also encourages the utility to keep costs below the projections and ensures that over-spends are not approved until a prudence review in the subsequent rate case. However, the one-way nature of the reconciliation still incentivizes the utility to inflate its capital projections to ensure that it does not exceed its capital cost forecast. Just as importantly, it provides no incentive to increase efficiency.<sup>23</sup> Thus, reconciliation mechanisms should generally be avoided in the context of MRPs.

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<sup>21</sup> A reconciliation mechanism and an ESM are related but distinct mechanisms. A downward reconciliation only applies when the utility doesn't spend its forecasted revenue requirement. An ESM only applies when revenues exceed costs. For example, consider a utility without decoupling that experiences a rate year where electricity load was higher than expected. In that same rate year, the utility spends its entire revenue requirement. In this scenario, the utility recovers more revenues than allowed under the MRP revenue cap and earns an ROE above authorized ROE. Under an ESM the utility would have to return a portion of the excess earnings to customers. However, there is no downward reconciliation because the utility spent 100% of its revenue requirement (i.e., spending cap).

<sup>22</sup> New York Public Service Commission, Order Adopting Terms of Joint Proposal and Establishing electric and Gas Rate Plans with Additional Requirements, Cases 22-E-0064 and 22-G-0065, July 20, 2023, at 18.

<sup>23</sup> The California Public Utilities Commission (CPUC) has objected to such claw-back mechanisms precisely because it erodes the utility's incentive to be efficient. The CPUC explains:

"...we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utility's bottom line, which means profit. In the short term, between general rate proceedings, the shareholders benefit when the company's management can 'do it for less,' and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. Keeping this incentive for utility management is a cornerstone of ratemaking, which leads us to look askance at proposals for immediate 'give backs' of all cost savings to ratepayers. If ratemaking ever becomes so conceptually upside down that utility management loses the economic incentive to exercise its business acumen, California will be in a sad posture and will suffer under utility management which is lethargic with a 'cost plus' mentality."

See: California Public Utilities Commission, D.85-03-042, 17 CPUC2d 246, at 254, as cited in D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 152.



## ***Recommendations for Virginia***

To preserve cost-containment incentives, an MRP framework in Virginia should not include any reconciliation.

## **Revenue decoupling**

### ***Overview***

Under traditional ratemaking, the Commission sets base rates in a base rate case and these remain fixed until the next base rate case. Under this approach, any change in sales between rate cases causes the utility's revenues to increase or decrease, depending on whether the actual sales exceed or fall below the projections. This approach makes revenue unpredictable. It also induces the utility to take actions that increase electricity sales (thereby increasing revenues), while avoiding actions that would reduce electricity sales such as energy efficiency or distributed generation.

Revenue decoupling addresses this problem by severing the direct link between sales and revenues. Under a decoupling mechanism, the utility recovers its authorized revenue requirement independently of fluctuations in customer electricity use. If actual revenues fall short of the authorized amount for any reason (e.g., due to weather, economic conditions, energy efficiency measures, or customer-owned generation), the regulator applies a surcharge to customer bills, so as to produce the missing revenues. Conversely, if revenues exceed the authorized level (e.g., due to higher-than-expected sales from weather or economic growth), customers receive a bill credit. The decoupling mechanism produces these adjustments through a transparent, formula-based process on an annual or monthly basis.

Revenue decoupling neither guarantees utility profits nor automatically raises rates. Rather, it provides greater revenue stability. Moreover, ratemaking with revenue decoupling aligns utility revenues with actual costs more closely than ratemaking without revenue decoupling.

### ***Recommendation for Virginia***

Although it is not required as part of an MRP, decoupling could improve the current regulatory framework in Virginia. However, as with other MRP design elements, the impact of decoupling will be weakened if the MRP does not include the revenue requirements included in RACs.

While decoupling will help to remove the disincentive for utilities to invest in energy efficiency, it does not create an incentive for them to do so. Utilities are still incentivized to prefer capital investments to demand-side resources in order to grow rate base and profits. For this reason, it is important that decoupling is implemented along with more aggressive energy efficiency savings targets.

## Earnings sharing mechanisms

### *Overview*

The primary purpose of earnings sharing mechanisms (ESM) is to ensure that utility earnings do not become excessive during MRPs. The vast majority of these ESMs are one-way adjustments that cap the potential over-earning of the utility and require that the utility share some of its over-earnings with customers. Although ESMs reduce risks to customers, they also reduce the utility's incentive to reduce costs. This is because under an MRP, the utility's most direct means of increasing earnings is to reduce its costs. An ESM requires that the utility return some or all of these cost savings above a certain threshold to customers.

### *Existing design*

Under the current biennial review framework, Dominion must credit 85 percent of its earnings between 100 percent and 150 percent of its allowed rate of return to customers. Any earnings exceeding 150 basis points above its fair return are returned to customers.

Dominion's ESM (referred to as an earnings test) protects ratepayers by not allowing for the recovery of under-earnings, thereby encouraging Dominion to keep spending within its revenues. However, the lack of a deadband weakens cost-containment incentives for the utility. With no deadband, Dominion returns the majority (85 percent) of any earnings above its allowed return to customers. Deadbands of 50–100 basis points are commonly used to provide utilities with a stronger incentive to reduce costs, since the utility is able to retain more of the cost savings in the form of higher profits. For example, National Grid in Massachusetts has a deadband of 100 basis points, above which 75 percent of the earnings flow to customers.<sup>24</sup> Similarly, Hawaiian Electric has a deadband of 300 basis points.<sup>25</sup>

APCo operates under a different earnings sharing structure, with the utility retaining the first 100 basis points in excess of its allowed return, with anything greater than 100 basis points returned to customers. In other words, there is a 100 basis point deadband above the allowed return on equity that can potentially benefit the utility if it successfully reduces costs below its allowed revenues. This structure offers some incentive to APCo to operate efficiently so that it can boost its earnings.

### *Recommendations for Virginia*

It is paramount to view design elements in a comprehensive manner to understand potential adverse outcomes. For example, if the ARM is based on a utility-specific cost forecast, the MRP should contain additional customer protection measures to ensure that the cost forecast is reasonable. Ideally the cost forecast would be based on a transparent and robust planning process with stakeholder involvement. If the forecast is not transparent, the MRP could include a one-way reconciliation mechanism to avoid an

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<sup>24</sup> Massachusetts Department of Public Utilities Docket No. 23-150.

<sup>25</sup> Hawaii Public Utilities Commission, Docket No. 2018-0088.

outcome where the utility benefits from inflating its cost projections and protects customers from utility under-spend.

The inclusion of an ESM in Virginia's MRP framework must be considered in light of other regulatory components, particularly the duration between rate reviews and the use of cost forecasts. Specifically:

- The current two-year rate period dampens any cost-control incentives since the utility would only retain earnings for one year until rates are reset in the next biennial rate review. For an ESM to be effective at creating cost control incentives the period between MRPs should be at least three years.
- Utilities currently recover numerous costs, including a large portion of costs associated with generation, through RACs. Any future MRP revenue requirement should include these costs. However, if these costs are escalated using a cost forecast developed by the utility, then there is a risk that the cost forecasts will be inflated. To guard against this risk, we suggest two options for ESMs:
  - If the cost forecasts are transparent and fully justified with supporting data, then it may be appropriate to allow the utility to retain a larger portion of any excess earnings (for example by allowing the utility to retain any over-earnings up to 100 basis points above the utility's allowed return on equity, and 25 percent of over-earnings above that threshold).
  - If there is less certainty regarding the accuracy of cost forecasts, then the ESM should be set to return the majority of over-earnings to customers (e.g., by allowing the utility to retain only 25 percent of any over-earnings up to a threshold of 100 basis points above the allowed return on equity, with all over-earnings above 100 basis points returned to customers).

If the utility's revenue requirement over the MRP term is based on either an external index or a cost forecast based on transparent and robust planning processes and the MRP has a stay out period of three or more years, it may be appropriate to include an ESM. In this instance, we recommend several improvements to the existing design.

#### Interaction between decoupling and ESMs

As discussed above, MRPs often include decoupling, in part because decoupling more clearly attributes earnings to utility performance rather than changes in sales volumes, which tend to be highly influenced by weather or economic activity rather than utility actions. If decoupling is implemented, the decoupling adjustment should be made before any determination of utility under- or over-earnings. For example, Con Edison has decoupling and an ESM. To calculate the ESM the company's actual earned ROE is calculated on its books of account for each rate year, excluding the effects of items like property tax refunds and revenue adjustments from decoupling.<sup>26</sup> In this way the calculation of the actual earned

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<sup>26</sup> New York Public Service Commission, Order Adopting Terms of Joint Proposal and Establishing electric and Gas Rate Plans with Additional Requirements, Cases 22-E-0064 and 22-G-0065, July 20, 2023, at 81.

ROE does not take into account any revenue adjustments from decoupling. This allows any earnings above or below the authorized return on equity to be more clearly attributed to utility actions rather than external variables.

## **Rate case stay-out period**

### ***Overview***

The stay-out period in an MRP defines the length of time before a utility is allowed to adjust its rates in a rate case. The duration between rate cases can have important impacts on utility cost-control incentives. Typically MRPs have stay-out periods of 3–5 years, which encourages the utility to manage costs and find cost efficiencies to keep costs below its allowed revenues. In contrast, under Virginia’s current two-year rate period, there is little incentive for the utility to control costs because if the utility overspends it only has to wait two years until rates are reset. In addition, the two-year review period creates significant regulatory burden on regulators and intervening parties, as rate cases are filed frequently.

When determining the appropriate stay-out period for an MRP, regulators must balance two competing factors:

- **Cost-containment incentives:** A longer stay out period improves the ability of utilities to benefit from implementing cost reductions during an MRP, improving the cost-containment incentives provided by an MRP.
- **Risk:** A shorter stay-out period reduces risks to customers by adjusting rates to reflect actual costs frequently. If there is little certainty regarding whether the MRP revenue targets are set appropriately, then a shorter stay-out period may be warranted. Uncertainty regarding revenue targets may arise because: the revenue targets are set based on cost forecasts that are not sufficiently transparent or well-vetted.

### ***Recommendations for Virginia***

If the Commission finds there is too much risk associated with utility cost-forecasts used to develop revenue requirements over a multi-year period, an MRP may not be an appropriate choice for Virginia and the current two-year rate period may be an appropriate way to balance cost-containment incentives with risk. However, if the MRP ARM is based primarily on an external index we recommend a three-year MRP. If the MRP is based primarily on well-vetted and transparent utility-specific cost forecasts than a longer stay-out period of 4–5 years is appropriate, since the planning process provides greater certainty to all parties that the allowed revenues will be sufficient but not excessive.

## **Performance incentive mechanisms**

PIMs can help to align a utility’s financial incentives with the public interest. However, PIMs should be designed in concert with cost recovery mechanisms. For example, if the utility can recover the costs of meeting a PIM target through a tracker, then it has every incentive to spend as much as required to meet the PIM target, even if the costs outweigh the benefits.





PIMs should be implemented in Virginia alongside incentives to control the costs associated with meeting the PIM targets. In addition, the total value of potential PIM rewards plus the utility's base return on equity should not be excessive, or the utility will have a stronger incentive to expand its rate base.

Synapse discusses PIM design in its companion PIMs report.

### 3.3. Evaluating MRP proposals

As the Commission and Virginia Energy evaluate potential performance-based regulatory tools, including MRPs, we recommend thorough evaluation of each proposal to ensure that it will provide greater utility cost control, lower rates, reduced administrative burden, and alignment with Virginia's energy policy goals than the current framework and compared to traditional cost-of-service regulation. Table 4 below provides a set of evaluation criteria to help assess the merits of an MRP proposal.

**Table 4. Evaluation criteria for MRPs**

Category	Key Criteria
<b>Information and Resource Asymmetry</b>	<ul style="list-style-type: none"> <li>• Are the allowed revenues set based on an objective, external index, or are they based on the utility's own estimates? If the latter, information asymmetry will be high and problematic without comprehensive and transparent integrated planning at the generation, transmission, and distribution levels.</li> <li>• Is a capital plan provided in the context of a comprehensive integrated distribution plan and integrated resource plan?</li> <li>• Are alternatives to proposed investments appropriately considered and evaluated, including third-party provided solutions such as non-wires alternatives?</li> </ul>
<b>Risk</b>	<ul style="list-style-type: none"> <li>• Does the risk associated with managing the utility remain with utility managers? Or are risks shifted to ratepayers?</li> <li>• Who bears the risk of cost overruns?</li> <li>• Who bears the risk of forecast error?</li> <li>• Who bears the risk of stranded costs?</li> </ul>
<b>Core Services</b>	<ul style="list-style-type: none"> <li>• Is the utility maintaining an acceptable level of reliability and customer service?</li> </ul>
<b>Policy Goals</b>	<ul style="list-style-type: none"> <li>• Is the utility achieving energy policy goals beyond business-as-usual utility investments (e.g., resilience, grid modernization, distributed energy resource interconnection, energy efficiency, electric vehicle adoption, microgrids, customer empowerment, etc.)</li> </ul>
<b>Administrative Burden</b>	<ul style="list-style-type: none"> <li>• Does the MRP actually reduce administrative burden after the rate plan is approved?</li> </ul>

## 4. CONCLUSION

Establishing an MRP in Virginia presents an opportunity to modernize the regulatory framework while promoting cost efficiency, investment certainty, and customer protection. However, for an MRP to be effective, it must be thoughtfully structured to balance the interests of utilities and ratepayers. As evidenced by the Maryland experience, poorly designed MRPs risk shifting burdens onto ratepayers without delivering commensurate benefits. As Virginia considers adopting an MRP framework, it must give careful attention to key design elements such as ensuring that allowed revenues (adjusted through the ARM) do not directly track to utility costs, prohibiting reconciliation of utility overspending, creating a stay-out period that balances risks to customers with incentives for utilities to reduce costs, and developing an ESM that ensures that the utility does not over-earn excessively.

Overall, the design of Virginia's MRP should be guided by clear goals: encouraging prudent utility behavior, aligning utility incentives with public interest outcomes, and ensuring that risks and rewards are equitably shared between utilities and customers. Through thoughtful integration of these design elements, Virginia can achieve a more resilient, efficient, and customer-focused utility regulatory model.

