REPORT OF THE
VIRGINIA STATE CORPORATION COMMISSION

# Opportunities for Performance-Based and Alternative Regulatory Tools in Virginia (HJR 30, 2024)

TO THE GOVERNOR AND
THE GENERAL ASSEMBLY OF VIRGINIA

# HOUSE DOCUMENT NO. 5

COMMONWEALTH OF VIRGINIA
RICHMOND
2025

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
COMMISSIONERS
JEHMAL T. HUDSON • SAMUEL T. TOWELL • KELSEY A. BAGOT

October 15, 2025

The Honorable Glenn Youngkin
Governor, Commonwealth of Virginia

The Honorable R. Creigh Deeds
Chair, Senate Committee on Commerce and Labor

The Honorable Jeion A. Ward
Chair, House Committee on Labor and Commerce

The Honorable Scott A. Surovell
Chair, Commission on Electric Utility Regulation

Senate Committee on Commerce and Labor

House Committee on Labor and Commerce

Members of the Virginia General Assembly

Dear Governor Youngkin and Members of the Virginia General Assembly:

Please find enclosed the Report of the State Corporation Commission on the Opportunities for Performance-Based and Alternative Regulatory Tools in Virginia pursuant to House Joint Resolution 30 and Senate Joint Resolution 47 of the 2024 Virginia Acts of Assembly.

Please let us know if we may be of further assistance.

Respectfully submitted,

Samuel T. Towell
Chairman

Jehmal T. Hudson
Commissioner

Kelsey A. Bagot
Commissioner

Enclosure

# Opportunities for Performance-Based and Alternative Regulatory Tools in Virginia

## A Review of Regulatory Performance for Electric Utilities in Virginia and Evaluation of Performance-Based Regulation and Alternative Regulatory Tools to Improve Regulatory Outcomes

***Study for the Virginia State Corporation Commission, prepared in accordance with House Joint Resolution No. 30/Senate Joint Resolution No. 47***

*Docket No. PUR-2024-00152: In the matter concerning performance-based regulation and alternative regulatory tools for investor-owned electric utilities*

*August 2025*

Prepared by the Great Plains Institute and Current Energy Group for the Virginia State Corporation Commission. Technical support was provided by Pacific Northwest National Laboratory.

**Lead Authors**
Aileen Cole, Great Plains Institute
Dan Cross-Call, Current Energy Group

**Report Contributors**
Matt McDonnell, Current Energy Group
Trevor Drake, Great Plains Institute
Hallie Turner, Great Plains Institute
Jason Eisdorfer, Pacific Northwest National Laboratory
Jay Barlow, Pacific Northwest National Laboratory

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## Acronyms and Abbreviations

| | |
|---|---|
| APCo | Appalachian Power Company |
| ARM | Attrition relief mechanism |
| bps | Basis points |
| CAIDI | Customer Average Interruption Duration Index |
| Capex | Capital expenditure |
| CEG | Current Energy Group |
| COSR | Cost-of-service ratemaking |
| Commission | Virginia State Corporation Commission |
| Commonwealth | The Commonwealth of Virginia |
| CPCN | Certificate of public convenience and necessity |
| CSP | Competitive service provider |
| Department | Virginia Department of Energy |
| DER | Distributed Energy Resource |
| Dominion | Virginia Electric and Power Company, doing business as Dominion Energy Virginia |
| DSM | Demand-side management |
| ECM | Efficiency carryover mechanism |
| ESM | Earnings sharing mechanism |
| FERC | Federal Energy Regulatory Commission |
| GPI | Great Plains Institute |
| Joint Resolution | House Joint Resolution No. 30/Senate Joint Resolution No. 47 |
| IOU | Investor-owned utility |
| kWh | Kilowatt-hour |
| MEDs | Major event days |
| MW | Megawatt |
| MWh | Megawatt-hour |
| MRP | Multi-year rate plan |
| NCUC | North Carolina Utilities Commission |
| Opex | Operating expenses |
| PBR | Performance-based regulation |
| PIM | Performance-incentive mechanism |
| PNNL | Pacific Northwest National Laboratory |
| PSC | Public Service Commission |
| PUC | Public Utilities Commission |
| PURA | Connecticut Public Utilities Regulatory Authority |
| RAC | Rate adjustment clause |
| REC | Renewable energy credit |
| Regulation Act | Virginia Electric Utility Regulation Act |
| RFP | Request for proposals |
| RIIO | Revenue = Incentives + Innovation + Outputs |
| RPS | Renewable portfolio standard |
| ROE | Return on equity |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCC | Virginia State Corporation Commission |
| SSM | Shared savings mechanism |
| Totex | Total expenditures |
| VCEA | Virginia Clean Economy Act |

## Chapter 1: Executive Summary

In March 2024, the Virginia General Assembly passed House Joint Resolution No. 30 and Senate Joint Resolution No. 47 (hereafter referred to as the Joint Resolution).[1] The Joint Resolution directed the Virginia Department of Energy (Department) to conduct a stakeholder process on performance-based regulation (PBR) in Virginia. Per the Joint Resolution, the stakeholder engagement process was to inform a Virginia State Corporation Commission (SCC) study on the potential implications of implementing a performance-based regulatory structure for investor-owned electric utilities (IOUs) in the Commonwealth as a means to improve alignment with Virginia's goals.

This study intends to fulfill the requirements and meet the goals outlined in the Joint Resolution, which are provided in Section 2.1, *Introduction, Study Scope, and Legislative Directive*. The analysis in this study focuses on Virginia's two largest investor-owned utilities (IOUs): Virginia Electric and Power Company, doing business as Dominion Energy Virginia (Dominion), and Appalachian Power Company (APCo). This study also provides a list of recommended strategies for Virginia's consideration. These strategies offer pathways to more strongly incentivize utility achievement of the Commonwealth's desired outcomes, and are provided in Table 2 in Section 2.5, *Recommendations for Virginia*.

The SCC selected the Great Plains Institute (GPI) and Current Energy Group (CEG) to complete this study in fulfillment of these requirements. The SCC also secured technical assistance from Pacific Northwest National Laboratory (PNNL) through the State Assistance Technical Program. PNNL staff provided research and technical analysis support throughout the report development process. This study is being developed pursuant to Joint Resolution directives and SCC orders in Case No. PUR-2024-00152, *In the matter concerning performance-based regulation and alternative regulatory tools for investor-owned electric utilities*.

This report reflects the views and recommendations of GPI and CEG as independent consultants aided and informed by (i) the stakeholder process described herein, and (ii) additional technical consultants described above. The SCC initiated and coordinated the undertaking of this study as directed by the above-referenced legislation, but takes no position concerning the policy analysis or recommendations contained in this report.

### 1.1 What is Performance-based Regulation?

At the broadest level, PBR combines a set of regulatory mechanisms and processes that aim to align utility outcomes with regulatory objectives. The Joint Resolution provides a list of PBR and alternative regulatory tools to be evaluated. A regulatory framework is not inherently "performance-based" because it uses one or more of these mechanisms. Rather, effective

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[1] House Joint Resolution No. 30/Senate Joint Resolution No. 47 ("Joint Resolution"), *Requesting the State Corporation Commission, in collaboration with the Department of Energy, to study performance-based regulatory tools for investor-owned electric utilities in the Commonwealth*, Regular Session (Virginia 2024).

incentive regulation emerges when a comprehensive and complementary suite of regulations is structured to motivate outcome-oriented utility performance that delivers desired results.

A PBR framework can motivate the utility to manage costs without compromising service or reliability while calibrating financial incentives with public interest. When done well, PBR creates an improved regulatory structure that allows the utility to recover prudently-incurred costs and provides the utility with an opportunity to earn a fair return while holding it accountable to a set of identified areas of concern (outcomes or performance areas, such as those provided in the Joint Resolution). The utility is also empowered to make prudent and strategic business decisions, which should be flexible and not exhibit anti-competitive behavior that prevent customers or other suppliers from conducting business within broader policy and market structures. In this manner, PBR can provide a “lift all boats” incentive realignment, by which utilities’ interests align with customer interests and policy goals, and which are compatible with competitive business opportunities in the broader economy.

This approach contrasts with traditional cost-of-service ratemaking (COSR) in which the primary design imperative is to recover costs incurred to deliver primary utility services, plus a fair rate of return on capital (rate-based) expenditures. Under COSR, absent any controls or incentive realignment, utilities have a strong interest in maximizing capital expenditures (*e.g.*, by constructing new generation facilities or conducting expansive grid upgrades) rather than pursuing lower-cost, more operations-oriented strategies (*e.g.*, energy efficiency programs).

## 1.2 How Can Performance-based Regulation Benefit Virginia?

Interest in PBR reflects a recognition of the shortcomings of the COSR model, in addition to an expanded set of outcomes that are expected from the modern utility system. Legislators and regulators may pursue PBR as a tool to help achieve a wide array of policy goals or desired outcomes. While PBR can seek to address multiple objectives or outcomes, it is useful to prioritize and down-select to a subset of primary objectives when constructing PBR regulations. Participants in the Department’s stakeholder process also reflected this sentiment, stating a desire to clarify the specific goals and outcomes that a PBR structure would address in Virginia. Below we suggest a consolidated list of performance areas for Virginia electricity regulations, based on the Joint Resolution and informed by the Department’s stakeholder engagement process:[2]

- Cost control, including removing perverse incentives for the “capex bias”
- Affordability
- Reliability (reduced frequency and duration of outages)
- Environmental performance, including achievement of Virginia Clean Energy Act goals
- Customer service and satisfaction
- Program improvements (*e.g.*, customer enrollments, energy efficiency attainment, etc.)
- Promotion of new technologies and innovations

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[2] Virginia Department of Energy, *Performance-based Ratemaking (PBR) Study Stakeholder Report* (May 16, 2025), Parts 1 and 2 https://www.scc.virginia.gov/docketsearch/DOCS/85mt01!.PDF and https://www.scc.virginia.gov/docketsearch/DOCS/85m%2501!.PDF.

- Encouragement of alternative solution development

Virginia's identified policy and regulatory objectives correspond to the broad PBR objective to *improve utility performance*. From the Joint Resolution, those include performance improvements for affordability, reliability, and customer service; enhancing cost-containment incentives; and making progress on energy efficiency and decarbonization goals. Should the SCC undertake future work to design and adopt PBR reforms (that is, after the evaluation phase that is the focus of this study), then some formalization of priority outcomes is a useful starting point.

## 1.3 Recommendations

This study reviews many options and design considerations to improve electric utility regulations in Virginia. From the broad discussions of this study, we elevate a targeted set of six specific recommendations for focus:

1. **Continue rate adjustment clause (RAC) reform** to reduce the number of RACs and the total amount of costs collected through RACs.
2. **Open a fuel cost investigation** with the objective of creating a fuel cost-sharing mechanism or comparable reform to incentivize reduced fuel costs.
3. **Open an investigation of renewable portfolio standard (RPS) financial incentives** for the purpose of aligning utility incentives and risk-sharing to achieve greenhouse gas reduction goals.
4. **Develop a set of targeted performance-incentive mechanisms (PIMs)**, including updates to strengthen achievement of energy efficiency targets and select additional priority outcomes.
5. **Employ all-source competitive procurement** in future utility resource procurement in a manner that allows participation from resource alternatives, including clean energy supply and demand-side management (DSM) solutions.
6. **Develop an integrated PBR framework** with an externally-indexed revenue cap multi-year rate plan (MRP) and complementary mechanisms, including, for example, decoupling, earnings sharing mechanism (ESM) improvements, capex-opex equalization tools, and an integrated set of PIMs and shared savings mechanisms (SSMs) for priority outcomes.

In addition to these recommendations, we emphasize two cross-cutting considerations that can support more effective, outcome-aligned regulations:

- Ensure that the SCC has sufficient authority to properly design, implement, and maintain an effective regulatory framework.
- Place affordability and cost containment at the center of all regulatory decisions.

These recommendations, as well as essential design choices and the related considerations, are discussed further in the Legislative Report and throughout the Technical Report.

## 1.4 Structure of this Study

This study is divided into three chapters, summarized below.

**Chapter 1, *Executive Summary,*** describes the purpose of this study, provides a high-level conceptual overview of PBR, outlines potential benefits that a PBR framework can offer, and previews the primary recommendations of this work.

**Chapter 2, *Legislative Report,*** presents the primary findings and recommendations of this work, which respond to the requirements of the Joint Resolution and are drawn from the analysis contained in the Technical Report. It identifies some notable features and limitations of current Virginia electric utility regulations, explains different PBR mechanisms, and identifies ways that a PBR framework could help improve alignment with the regulatory objectives, performance areas, and desired outcomes outlined in the Joint Resolution.

**Chapter 3, *Technical Report,*** provides details and supportive information to help Virginia stakeholders and decision makers understand the current context related to utility ratemaking and regulation in the Commonwealth. The Technical Report is divided into several sections, which focus on the following items:

- Details on the Department's stakeholder engagement process
- Virginia's current regulatory and legislative context
- Utility performance under Virginia's current regulatory construct
- PBR and alternative ratemaking tools
- Ratemaking reform in other jurisdictions
- Potential implications related to competitive service providers and carbon leakage from the manufacturing sector

Each section in Chapter 3 contains details intended to inform decision makers who may be considering whether an alternative ratemaking construct could benefit Virginia, and to be responsive to the Joint Resolution.

# Chapter 2: Legislative Report

This Legislative Report provides decision makers with a high-level understanding of PBR, Virginia's current regulatory framework for electric IOUs, how the current framework may or may not incentivize achievement of the Commonwealth's priorities, and how a performance-based framework could address areas of misalignment, in accordance with the requirements established in the Joint Resolution. Chapter 3, *Technical Report*, provides further details and analysis related to these topics, including more comprehensive information regarding the PBR and alternative regulatory tools identified in the Joint Resolution.

## 2.1 Introduction, Study Scope, and Legislative Directive

The Joint Resolution directs the Department to conduct a stakeholder engagement process—including workshops, presentations, and discussions—to gather stakeholder perspectives on the use of PBR or alternative regulatory tools and to solicit proposed implementation models for Virginia's electric IOUs, to the extent feasible. It also directs the SCC to conduct a study evaluating the PBR tools and alternative regulatory tools discussed in the Department's stakeholder engagement process. The Department's stakeholder engagement report—which informed the content discussed in this study—is available in Case No. PUR-2024-00152, *In the matter concerning performance-based regulation and alternative regulatory tools for investor-owned electric utilities*.[3] For further information regarding the Department's stakeholder engagement process, please refer to Section 3.1, *Summary of Virginia Department of Energy Stakeholder Process*.

The Joint Resolution also requires that the SCC evaluate how a range of PBR and alternative regulatory tools identified in the Joint Resolution (and provided below) might help Virginia meet the following legislative objectives related to several regulatory outcomes and performance areas.[4]

***Legislative objectives excerpted below as provided in the Joint Resolution:***

(a) Provide an analysis of the current regulatory framework and the financial incentives such framework creates for investor-owned electric utilities and competitive service providers in the Commonwealth;
(b) Identify possible misalignments between such incentives for investor-owned utilities and competitive service providers and the Commonwealth's energy policy goals;
(c) Analyze performance-based and alternative regulatory tools used in other jurisdictions to correct such misalignments;
(d) Review the varying obligations on investor-owned utilities and competitive service providers;
(e) Analyze the potential impact of competitive service providers to all customers in the Commonwealth;
(f) Propose reforms to the current regulatory framework;

[3] Department's PBR Stakeholder Engagement Report (Part 1 and Part 2).

[4] Virginia General Assembly, Joint Resolution.

(g) Identify reforms that could be implemented under the current authority vested in the Commission, as well as reforms requiring additional enabling legislation; and
(h) Consider whether and how these tools assist in preventing carbon leakage from the manufacturing sector.

***Regulatory outcomes excerpted below as provided in the Joint Resolution:***

(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.

***Performance areas*** *excerpted below as provided in the Joint Resolution:*

(1) Reliability and resiliency;
(2) Affordability for customers;
(3) Emergency response and safety;
(4) Cost-efficient utility investments and operations;
(5) Customer service;
(6) Savings maximization from energy efficiency and exceedance of statutorily required savings levels;
(7) Peak demand reductions;
(8) Integration of distributed energy resources, including the quality and timeliness of interconnection of customer-owned and third-party-owned resources;
(9) Environmental justice and equity;
(10) Beneficial electrification, including in the transportation and buildings sectors;
(11) Maximization of available federal funding;
(12) Decarbonization of the Commonwealth's electricity sector;
(13) Cyber and physical security of the grid;
(14) Annual and monthly generation and resource needs in addition to hourly generation and resource needs on the 10 hottest and coldest days of the year; and
(15) Any other topics deemed relevant and useful to the Commission in its review of performance areas.

The Joint Resolution also directs attention to the following **PBR and alternative regulatory tools** (excerpted below as provided in the Joint Resolution, with italicized items added by the authors) to assist in electric IOU regulation in the Commonwealth:[5]

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[5] Virginia General Assembly, Joint Resolution.

- Reporting metrics,
- Scorecards,
- Performance-incentive mechanisms *(PIMs)*,
- Decoupling electricity rates from utility revenues *("revenue decoupling")*,
- Multi-year rate plans *(MRPs)*,
- Fuel cost-sharing mechanisms,
- Best practices for all-source competitive procurement,
- Strategies to equalize financial incentives to deploy capital and operational expenditures *("capex-opex equalization")*, and
- Other information deemed relevant or helpful by the Commission in its review.

This study addresses the broad scope and multifaceted objectives directed by the Joint Resolution. Where possible, the authors sought to synthesize general patterns or trends in Virginia's electric utility system and to organize common regulatory tools in a manner that promotes better understanding and opportunity for future action. The remainder of Chapter 2, *Legislative Report* presents those primary findings and recommendations, while Chapter 3, *Technical Report* delves deeper into specific features of current regulations, their outcomes, and options for ratemaking reform.

## 2.2 Current Regulatory Framework in Virginia

This section provides a high-level assessment of Virginia's current regulatory framework and associated outcomes for electric IOUs and their customers. The Technical Report includes a fuller review of current regulations that govern Virginia's electric utilities. It also identifies possible misalignments with the Commonwealth's energy policy goals. The general observations provided below reflect key takeaways from the more detailed analysis offered in the Technical Report.

### General Observations

#### *Current Regulatory Framework*

Virginia's regulatory framework is remarkably complex, which can make it challenging for intervening parties and interested citizens to constructively engage in the regulatory process. It also limits the ability of utilities and the SCC to adapt to developing circumstances in the energy system, as many ratemaking details are narrowly defined without room for holistic review of utility decision-making and prudence. This complexity is due, in part, to the fact that Virginia's electricity regulations reflect an unusually high degree of ratemaking via legislation. In many cases, precise details regarding ratemaking structures are defined in statute. In other US states and abroad, these details are more commonly established by the utility regulator in accordance with enabling authority granted by statute. The statutes typically establish higher-level ratemaking parameters, directing regulators to design more specific structures and evaluate utility proposals on their merits.

Virginia's current regulatory framework may have the effect of limiting the SCC's ability to apply expert judgment to the facts of a case in its ratemaking decisions. It may also limit opportunities to evaluate how different ratemaking structures interact and can be designed to achieve desired systemwide outcomes and over longer timeframes. Some constructive revisions have been made to authorizing statutes in recent years, including 2023 updates to the Regulation Act.[6] These updates renewed some SCC authority to determine critical ratemaking components like allowed return on equity (ROE). Yet there remains space to remove some of the more prescriptive elements of Virginia regulatory structures from statute (and to eliminate portions of statute that are expired or moot) while affirming overall regulatory objectives and design parameters.

### *Over-Reliance on RACs*

Virginia ratemaking, particularly for Dominion Energy, is overly reliant on rate adjustment clauses (RACs, or what are commonly referred to as riders). RACs can, in some cases, serve a useful purpose to provide cost recovery for public policy programs or factors outside utility control (*e.g.*, public benefits charges or revenue for individual programs outside a utility's core functions). However, Virginia ratemaking expanded the use of RACs well beyond these standard uses, creating an excessive reliance on RACs for costs that may be better suited for base rates. This heavy use of RACs has consequences, including the following:

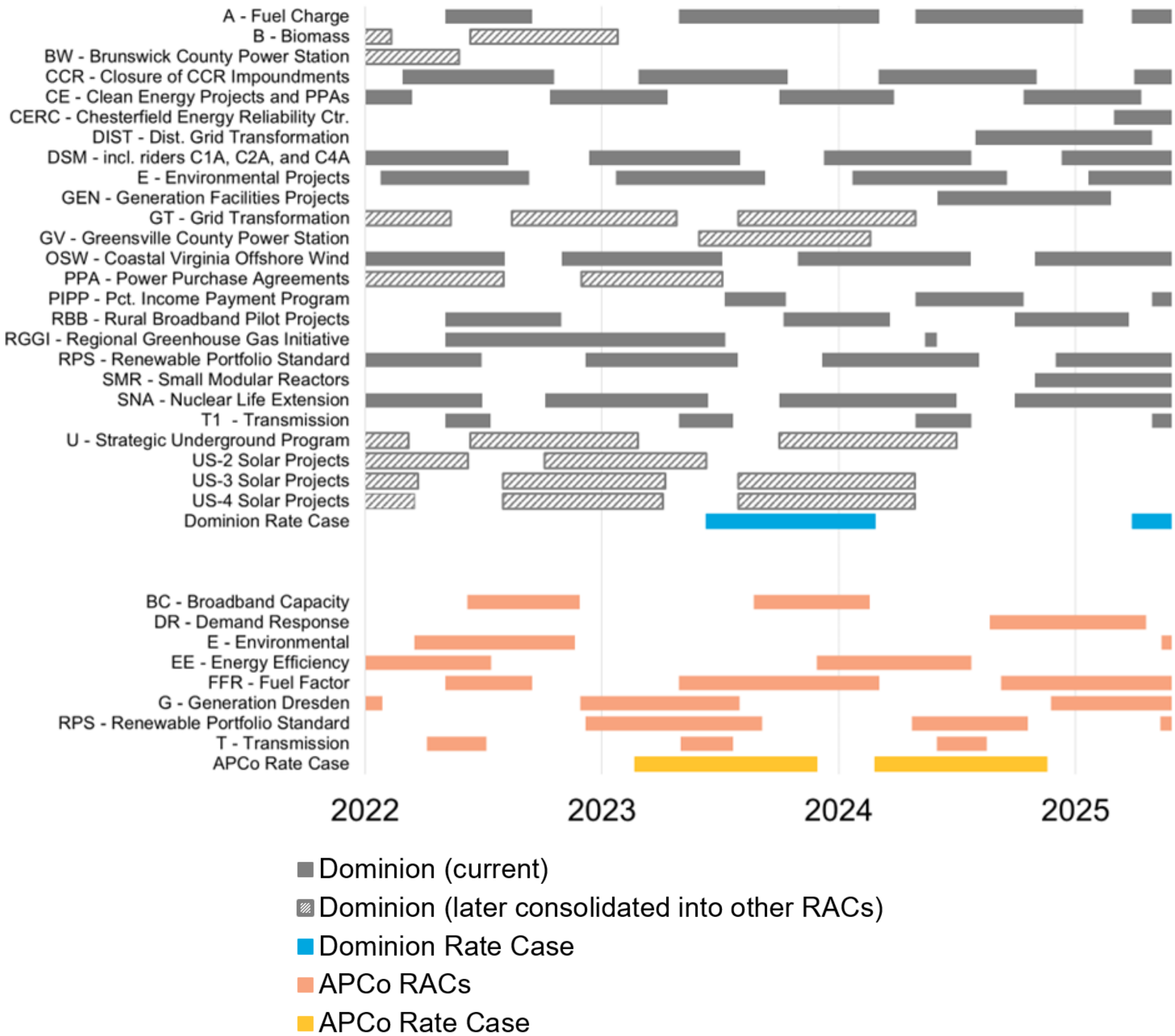
- Excessive insulation of the utilities from downside risks associated with their business decisions,
- Inappropriate guarantee of cost recovery and profit (ROE) by what effectively serves as a pass-through from ratepayers to the utility, and
- Diminished ability for regulators and intervenors to review prudency or cost contributors in a comprehensive and coordinated manner because reviews occur outside rate cases in a disconnected set of many proceedings.

RACs also impose additional administrative burden on the SCC and intervenors. The cumulative volume of RAC proceedings at the SCC is illustrated in graphical form in Figure 1 on the following page. As displayed in Figure 1, the heavy reliance on RACs leads to an associated overload of administrative activity at the SCC while also removing these costs from consideration in rate cases.

The 2023 Regulation Act updates encouraged some consolidation of RACs and directed select RACs to be migrated to base rates. While some RACs have been consolidated in response, significant improvement opportunities remain.

[6] For a summary of 2023 revisions to the Regulation Act, please refer to Report to the Virginia General Assembly RD572 (*Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia*). For the entirety of the Regulation Act, including all modifications to-date, please refer directly to Title 56, Public Service Companies, Chapter 23, Virginia Electric Utility Regulation Act.

**Figure 1: Virginia RAC proceedings for APCo and Dominion, January 2022–May 2025**




Sources: "Residential Rates," Dominion Energy, accessed July 24, 2025; "Business Rates," Dominion Energy, accessed July 24, 2025; Appalachian Power Company (APCo), *Virginia SCC Tariff No. 28*, December 11, 2024; Appalachian Power Company (APCo), *Select Schedule Charges and Associated Rider Charges*, January 1, 2025. Figure by CEG and GPI with assistance from PNNL.

Note: Timelines of proceedings for those RACs in effect on the Dominion tariff as of June 1, 2025 and APCo tariff effective January 1, 2025; see the Technical Report for additional discussion of this graphic.

## Regulatory Outcomes

### *Affordability*

Virginia's electricity prices (rates) are competitive with peer states and national averages. Prices are increasing, however, and trends in Virginia and across the country portend significant electricity price increases in the years ahead. This is exemplified by a projected increase of more than 50 percent in Dominion's rate base from 2024 to 2029 (see *Anticipated growth in Dominion's rate base, by category*, in the Technical Report) and a commensurate increase in ratepayer costs. This outlook suggests a heightened need for regulatory review and incentive alignment to promote cost efficiency and affordability for customers. Whatever the regulatory approach, PBR or otherwise, every opportunity for cost-efficient investments and operational improvements in utility performance is important.

Fuel costs are one large cost component of Virginia electricity bills and offer potential for incentive realignment. Currently, the fuel costs associated with utilities' generation fleet are passed directly to customers, meaning that the utilities are not necessarily incentivized to seek the lowest cost fuel options for their system. Alternative regulatory pathways exist that can incentivize more prudent utility spending on fuels, share fuel costs among both customers and the utility, and help to incentivize energy efficiency and demand-side resources that reduce the total amount of fuel the utility must purchase. Reducing the overall fuel costs that customers are responsible for is a useful strategy to improve affordability. Alternative planning and procurement methods can also help to ensure that least-cost resource options are considered throughout utility departments and business practices.

### *Decarbonization*

There is notable misalignment between utility financial incentives and Virginia clean energy policy, including decarbonization goals. For example, because utilities' costs associated with renewable portfolio standard (RPS) compliance are borne by ratepayers, utilities lack meaningful financial incentives to align with the Commonwealth's decarbonization goals. As discussed more in the Technical Report, RPS compliance in Virginia functions mainly as an economic procurement activity and accounting exercise that is detached from the actual resource supply mix. This is due, in part, to utilities' ability to use renewable energy credits (RECs) to achieve RPS targets without necessarily reducing greenhouse gas emissions associated with their own generation resources.

Virginia's RPS structure also demonstrates little incentive for utilities to pursue cost-effective RPS attainment, as associated costs—including the "penalty" for failing to achieve compliance—appear to function entirely as a pass-through to customers. This structure may encourage some investment in renewable energy resources, but it lacks a meaningful incentive for utilities to adjust their investment and operational strategies to optimize clean energy most cost-effectively.

### *Limited PBR in Current Regulations*

Some limited PBR mechanisms exist in Virginia, including PIMs for energy efficiency and an earnings sharing mechanism (ESM) that offers some protection from outsized utility profit.

However, when compared to more inherent utility financial incentives to grow capital rate base and to guarantee (derisk) revenue streams to the maximum extent possible, these existing PBR mechanisms provide a relatively small incentive for utilities to meet the Commonwealth's goals. Although limited in their present form, existing PBR mechanisms in Virginia are useful structures that can be learned from and built upon if the Commonwealth seeks to better align ratemaking with utility performance.

### Overall Assessment: Potential for Reform to Meet Modern Needs

The Virginia electricity regulatory system has performed relatively well over time, particularly for conventional outcomes of cost and reliability. Those accomplishments should be preserved. However, they are at risk due to changing conditions, including forecasts for very large increases in electricity demand and large capital investment plans in the next decade and beyond.

As reflected in the Joint Resolution, the Commonwealth also expects more from the electricity system and its utilities, today and in the future. That includes modern objectives for a decarbonized economy, resilience from severe weather events, environmental justice needs, integration of new technologies, new customer program offerings, and expectations for utility innovation. These expectations expose a mismatch between the traditional COSR model and modern needs. COSR was well-suited to 20$^{th}$-century objectives for electricity system buildout to provide universal, safe, and reliable service at affordable rates.

Now, as technical capabilities have improved while system conditions (as well as the future energy outlook) have changed, traditional COSR is less suited to the task at hand. This is not a diagnosis limited to Virginia; regulators, policy makers, and numerous stakeholders have identified inherent flaws in prevailing regulations across the US and elsewhere. Central to these concerns is the premise that under a traditional COSR framework, increased capital investment yields increased utility earnings. That paradigm is at odds with business approaches in a competitive market environment, which seek to maximize profit through lowering costs below revenue. Competitive firms do not achieve this exclusively through capital investment, but rather through strategies that seek the highest value (for the firm as well as for customers) through a combination of short-term costs and longer-term investments.

As the Commonwealth pursues expanded objectives for the power system, and limitations or flaws in current regulations are evident, there is a need and opportunity to update regulations for new realities. Reform options are available, which can build upon COSR structures with increased attention to utility incentive alignment for cost efficiency and a targeted set of priority outcomes. Concurrently, the SCC and Virginia's regulatory community of intervenors and utilities can learn, employ, and refine new tools to support fuller achievement of shared goals. This will require extensive collaboration to identify areas for priority attention—whether through narrowly targeted improvements or broader reforms in the manner of an integrated PBR framework—but it is a necessary commitment if new, balanced regulations are desired.

## 2.3 Overview of PBR Mechanisms

The Joint Resolution presents a hypothesis that PBR and other alternative regulatory tools have the potential to improve financial incentives to better align utility performance with the

Commonwealth's policy goals. As described here and in the Technical Report, PBR-oriented regulatory reform offers great potential to promote better utility performance and to achieve desired system outcomes. Successful pursuit of PBR reforms also requires a significant political commitment, as well as commitment by state regulators and intervenors, to thoughtfully design new incentive structures that properly integrate and account for complex and interactive system effects. In that light, PBR should be viewed both as a powerful set of tools to enable improved utility alignment with desired outcomes, and as a toolset that requires care, attention, and ongoing maintenance to ensure achievement of those outcomes.

PBR mechanisms can be designed and organized in many ways. This can include narrowly targeted performance incentives for a discrete outcome (*e.g.*, improved reliability or energy efficiency). Alternatively, it can include integrative designs that more comprehensively reorient the utility business enterprise toward modern energy system objectives. This report emphasizes the latter: integrated PBR structures that are aligned with the multiple objectives expressed in the Joint Resolution and by Virginia stakeholders. That said, targeted PBR interventions are also viable and can improve outcomes. More narrowly targeted mechanisms, however, may be less successful at fulfilling the broad, interconnected ambitions that are stated in the Joint Resolution.

### PBR Mechanisms Defined

We employ a three-part framework to organize and define potential PBR mechanisms. If developed through this connected approach, PBR can operate in a more coordinated and systemic manner, which is a practical evolution of COSR. In practice, state policy makers and regulators may decide to employ a subset of these mechanisms, but it is critical to understand each tool's place within a broader structure and its potential to shift utility financial incentives.

Table 1 summarizes this framework, dividing primary PBR mechanisms into three categories (revenue adjustment mechanisms, performance mechanisms, and other regulatory structures), and defines each category and mechanism. Variants on this framework are discussed in PBR literature and have been used in reforms undertaken in some US states (including Hawaii and Connecticut). For further details on these PBR mechanisms, including important design and implementation considerations, please refer to Chapter 3.4, *Detailed Overview of Performance-based and Alternative Regulatory Tools*.

**Table 1: Three-part PBR framework**

| | |
|---|---|
| **Revenue Adjustment Mechanisms** Relate to a utility's primary cost recovery and profit structures. Provide foundational ratemaking adjustments that balance utility and customer (ratepayer) interests to fairly collect target revenues. Include PBR tools that shift revenue determinations away from a backward-looking view of costs and sales to a more future-oriented approach that incentivizes cost control. | |
| **Multi-year rate plan (MRP)** | Create cost-containment incentives and greater management discretion to improve utility operations and their investment decisions. Also, reduce the number and frequency of rate cases. |
| **Earnings sharing mechanisms (ESMs)** | Support an opportunity for the utility to earn a fair return while sharing with customers the cost efficiency and savings that can result from an MRP or other performance incentives. |
| **Revenue decoupling** | Mitigate utilities' "throughput incentive" to sell higher volumes of electricity. Can also provide revenue stability to the utility, reducing the perceived utility risk profile. |
| **Capex-opex equalization** | Address the capital expenditure bias inherent in traditional COSR, thereby providing utilities with more interest and earning opportunities to pursue alternative solutions. |
| **Performance Mechanisms** Provide targeted incentives for a utility to deliver desired outcomes that align with policy and customer priorities. Can be reputational or financial incentives. Financial incentives may be realized as *ex post* additions or subtractions to allowed revenues and earnings as established in rate cases or in individual rate adjustment clauses. | |
| **Reporting metrics** | Track outcomes in performance areas identified for attention to provide transparency and a better understanding of system performance. |
| **Scorecards** | Create targets for system performance, which are tracked publicly, and create a reputational incentive for performance improvement. |
| **Performance-incentive mechanisms (PIMs)** | Reward or penalize utility performance with earnings opportunities (or deductions) upon base rates to create heightened attention to key performance areas deemed important for improvement. |
| **Shared savings mechanisms (SSMs)** | Encourage cost savings for a targeted cost center (*e.g.*, a capital project or DSM program). Ensure that customers receive a share of benefits while also aligning utility financial interests with the pursuit of savings. |
| **Fuel cost sharing** | Incentivize utilities to control fuel costs and increase their self-interest in fuel-reduction strategies such as energy efficiency while maintaining appropriate protection from market forces. |
| **Other Regulatory Structures** A collection of other reforms that do not fit neatly within the above categories, but which can modernize utility practices or institutional structures and directly relate to primary system functions or objectives.[a] | |
| **All-source competitive procurement** | Updates to procurement processes to enable the acquisition of new supply resources, in which requirements for capacity or generation are technology- and ownership-agnostic. Can help to meet energy demand with least-cost resources. |
| **Innovation programs** | Programs or institutional arrangements to test and scale innovation. While these are sometimes considered under the banner of utility pilots or demonstration projects, attention has recently shifted to alternative arrangements (sometimes referred to as |

| | |
|---|---|
| | a “regulatory sandbox”) with increased attention to connect technology or program innovation to scalability. |
| **Independent energy efficiency utility** | A new institutional arrangement in which the role of customer-oriented energy efficiency program administration is granted to a separately chartered organization. There are additional options for scope and mission; for example, functions can be broader than energy efficiency to include clean energy or DSM program management for customers. |

[a] Numerous mechanisms can be included in this “Other” set (*e.g.*, advanced rate design and pricing), depending on the focus or objectives of the analysis. In this report, we focus on a limited set that may be most relevant to current Virginia circumstances and stakeholder interests.

### Overarching Considerations for PBR Development

If the Commonwealth decides to move ahead with PBR-oriented reforms, Virginia policy makers, the SCC, and intervenors will need to consider many design choices and procedural requirements. Some of these are identified and discussed in Chapter 3.4, *Detailed Overview of Performance-based and Alternative Regulatory Tools,* and throughout the Technical Report, which can serve as a reference for future activities or regulatory design in Virginia. Among these design choices and procedural requirements, we emphasize some primary considerations:

- **Integrative design practices are essential.** Utility regulations do not exist in a vacuum. Each individual mechanism or incentive structure operates within a connected system of influences, procedures or planning activities, and institutional priorities among various actors. Decisions and their results are also dynamic over time, meaning there is an undeniable interaction between a utility planning process or proposed investment in one docket and year, with revenue determinations or management decisions addressed later in other dockets and venues. As in any regulatory system, a robust PBR approach must be attentive to connections to ensure that new structures are purpose-built to have their intended effect.
- **Mutually beneficial outcomes are possible and desirable.** PBR has been resisted or viewed critically in some contexts or peer jurisdictions. That includes concerns raised by utilities, consumer advocates, and representatives of some customer classes. Those concerns are warranted in the case of a poorly designed regulatory structure. However, PBR offers a robust framework and set of tools that—when appropriately designed and implemented—can provide balanced and advantageous outcomes to many parties. It is a structure that can rebalance utility ratemaking among utility financial integrity, essential cost-containment imperatives, and achievement of additional regulatory objectives. Effective PBR design preserves utilities’ opportunity to earn a fair return—and in some cases to increase their earning potential—while placing the utility in a position to succeed on the merits of its business management practices. In this manner, PBR can and should improve upon identified shortcomings of prevailing regulatory structures.
- **Regulators hold important expertise to guide PBR design and enactment.** Leadership by, and empowerment of, the regulator is needed to support integrative design, create a constructive framework, and design PBR features that align with the public interest. New authorities or competencies may be required to put the regulator in

an effective leadership position. If appropriately empowered and committed to the effort, state regulators can guide the system to an improved structure.

- **Legislative direction is helpful.** It can be counterproductive to legislate precise details of mechanism design or incentive amounts, but regulators and intervenors benefit from clear policy principles and priority outcomes serving as a North Star. Well-crafted legislation can set the primary objectives for incentive structures, as well as establish parameters or key features that should be employed.
- **Details matter.** Careful attention should be paid to the structure of each mechanism. For example, adoption of an MRP is not, in itself, "performance-based." In some cases, states have adopted multi-year stayout periods that do not induce meaningful cost control because the longer period is not paired with essential features such as a cap on allowed revenues with re-basing of revenues between MRP periods. This demonstrates the importance of careful attention to underlying details and interactive effects to ensure that new tools employ identified best practices.
- **PBR development should be undertaken as a robust stakeholder engagement process.** The Department's stakeholder engagement process and this report can serve as a foundation for future PBR development. However, more work will follow over a period of months and years following legislative direction or SCC initiation of applicable proceedings. This iterative approach—informed by participation from interested parties—can provide an extremely healthy and constructive engagement and public participation process to get a fuller understanding of regulatory structures, evaluate specific opportunities, and then propose and refine detailed mechanisms.
- **There is opportunity to build and adapt.** This report emphasizes broad-based or comprehensive PBR structures; however, those are not an absolute requirement. Particularly in Virginia, where PBR experience is more limited to date, there is merit to introducing targeted improvements to utility incentives for priority outcomes, as well as fixing flaws in current ratemaking. Indeed, this is how progress is made in most or all peer jurisdictions. PBR is also not a "set it and forget it" structure. It requires ongoing attention to monitor and uphold the core structures or objectives a jurisdiction may adopt. Setting identified objectives and committing to continued improvements related to those objectives can move the system toward better performance over time.

## 2.4 Other Considerations

The Joint Resolution also directs the SCC to study the role of competitive service providers (CSPs) and the potential for carbon leakage from the manufacturing sector, with respect to PBR. However, because these topics are not directly related to the regulatory framework that governs the Commonwealth's IOUs, the implications of utility ratemaking structures on these issues are indirect and diffuse. Stakeholders in the Department's process also expressed very little interest in devoting time to these issues in workshops. As a result, less attention is paid to these in this report. A fuller analysis of CSPs and carbon leakage from the manufacturing sector would require devoted policy or techno-economic research to investigate the interactive effects between utility performance and regulatory incentives, and potential implications on downstream market participants. Nonetheless, we share some perspectives and provide a directional overview of potential impacts in these areas. For additional details on these topics, please refer to Chapter 3.6, *Competitive Service Providers and Carbon Leakage from the Manufacturing Sector.*

### Competitive Service Providers

The SCC does not regulate CSP rates, as CSPs operate in a competitive retail electricity market. In other words, changes to the regulatory framework for Virginia's electric IOUs would not necessarily apply to CSP customers' rates. However, the Joint Resolution defines CSPs as not only licensed retail electricity suppliers (consistent with definitions used elsewhere in Virginia statute), but also as entities with generation or transmission assets that sell electricity to customers (*i.e.*, IOUs). This reflects a possible conflation of terms, or maybe an interest in seeing IOUs compete on a more level playing field with CSPs. Regardless, it is unlikely that business operations for competitive retail electricity providers would be substantially different if Virginia adopted a more performance-oriented regulatory framework for its electric IOUs. However, we would expect that CSPs would also experience a more level playing field in the market to the extent that PBR or alternative regulation creates a closer mimicry of competitive market practices for regulated utilities.

### Carbon Leakage from the Manufacturing Sector

Carbon leakage refers to a scenario in which a carbon-emitting industry moves some or all of its operations to a jurisdiction with less strict emissions standards or policies. The outside jurisdiction could be attractive to industrial customers if it has lower electricity rates. Whether such a move would result in carbon leakage will depend on the carbon intensity of the electricity used in different service territories. Ultimately, if the introduction of an alternative regulatory framework were associated with carbon leakage from the manufacturing sector, the pathways through which the carbon leakage occurred would be indirect in nature and would depend on many variables beyond the PBR framework itself. Nonetheless, regulators should consider the needs of industrial customers when evaluating which PBR or alternative regulatory tools might best support cost-efficient progress toward the Commonwealth's goals.

## 2.5 Recommendations for Virginia

This report identifies many options and design considerations to improve electric utility regulations in Virginia. From these, we elevate a targeted set of chief concerns and have developed a list of recommendations that the Commonwealth can consider.

First, we emphasize two cross-cutting considerations that can support more effective, outcome-aligned regulations:

- **Ensure that the SCC has sufficient authority to properly design, implement, and maintain an effective regulatory framework.** This theme is reflected throughout this report, and fulfillment of its principal intent will permeate many decisions, statutory updates, and regulatory activities, large and small. Beginning with the 2007 Regulation Act and continuing for years, Virginia regulations became excessively prescriptive in legislated statutes. The General Assembly has recently made practical updates to authorizing statutes that tend more toward *directing (or allowing)* the SCC to act on areas within its regulatory authority, rather than prescribing specific utility revenue constructs. The General Assembly should feel encouraged to continue making such practical updates, while the SCC can embrace its authorities to fulfill public interest objectives.

- **Place affordability and cost containment at the center of all regulatory decisions.** As inflationary effects and grid investment needs bring unavoidable cost increases, cost-conscious utility management is paramount. Whether it is PBR in name or within any regulatory effort, the SCC should undertake strategies that enable effective monitoring of utility investments and establish cost-containment mechanisms to incentivize efficient business decisions.

We identify six specific recommendations to improve Virginia regulations. Each of these could be pursued independently, or they can be tackled in parallel in a coordinated manner through a more comprehensive regulatory reform effort. The recommendations are as follows:

1. **Continue rate adjustment clause (RAC) reform** to reduce the number of RACs and the total amount of costs collected through RACs.
2. **Open a fuel cost investigation** with the objective of creating a fuel cost-sharing mechanism or comparable reform to encourage reduced fuel costs.
3. **Open an investigation of renewable portfolio standard (RPS) financial incentives** for the purpose of aligning utility incentives and risk-sharing to achieve greenhouse gas reduction goals.
4. **Develop a set of targeted performance-incentive mechanisms (PIMs)**, including strategies to more strongly incentivize achievement of energy efficiency targets and select additional priority outcomes.
5. **Employ all-source competitive procurement** in future utility resource procurement in a manner that allows participation from resource alternatives, including clean energy supply and DSM solutions.
6. **Develop an integrated PBR framework** with an externally-indexed revenue cap multi-year rate plan (MRP) and complementary mechanisms, including, for example, decoupling, earnings sharing mechanism (ESM) improvements, capex-opex equalization tools, and an integrated set of PIMs and shared savings mechanisms (SSMs) for priority outcomes.

Each of these recommendations provides an opportunity to improve utility performance and alignment with the Commonwealth's goals, and we suggest that some or all should be considered for adoption. Among these, developing an integrated PBR framework (Recommendation 6) is possibly the most complete and far-reaching pathway to highly impactful system reform. It is also most effective when undertaken in coordination with (or accounting for) other developments across the regulatory system, including those other targeted reforms identified here. While this effort would arguably provide the highest impact in terms of redirecting utility decision-making to pursue broadly aligned objectives, it also requires significant time commitment. It would also require dedication to ensuring that the development process fosters an environment of shared expertise and co-development between the regulator and intervenors.

Table 2 expands on this shortlist of specific recommendations. Each recommendation in the table includes a brief description, rationale, and suggestion for which entity or entities have responsibilities associated with implementing the recommendation. Important design considerations related to these are included in the Technical Report. In most or all cases, the SCC would need to manage a proceeding to create a well-functioning mechanism that is fit for the Virginia context. In some cases, those proceedings could be directed by the General Assembly. In other cases, a statutory change might be needed to remove existing structures and give the SCC authority to make refinements.

**Table 2: Recommendations for consideration to improve Virginia electric utilities' incentive alignment**

| Recommendation | Rationale | Responsible Entity |
|---|---|---|
| 1. Continue progress to reduce the number of utility costs that are recovered via RACs by pursuing the following:<br>a. Identify which costs utilities are currently authorized to recover through RACs (including under Virginia Code § 56-585.1) that might be better recovered via base rates. Also, evaluate which RACs are or are not appropriate to be paired with a guaranteed ROE.<br>b. Evaluate which existing RACs (for costs that will remain as RACs) can be appropriately consolidated while retaining sufficient transparency. | Virginia relies more heavily on RACs than is common in other jurisdictions. Overall, this results in greater revenue certainty for utilities. It also diminishes utilities' incentive to contain costs that are automatically recovered via RACs (often with a guaranteed ROE), as opposed to those costs being subject to more involved prudency reviews side-by-side with base rates or related costs.<br><br>The SCC is authorized to consolidate RACs and has recently done so. This offers significant efficiency benefits, as Virginia's large number of RACs are reviewed in individual proceedings, resulting in a significant administrative burden for regulators, utilities, and intervenors alike. Consolidation should be limited to costs that are best suited for the RAC approach, and for RACs that can be logically grouped to support common objectives and cost centers. | *General Assembly:*<br>• Update/refine statute as needed to move additional RACs into base rates. Also, give the SCC additional authority to initiate and enact changes for RAC consolidation and/or movement of RAC costs into base rates.<br><br>*SCC:*<br>• Continue exploring, identifying, and consolidating RACs that could be logically grouped. |
| 2. Allow adoption of fuel-cost sharing mechanisms for Virginia electric IOUs, in support of shared benefit and fuel cost management. | Fuel cost sharing is a well-established approach to improve performance related to affordability, decarbonization, energy efficiency, and other performance areas that stakeholders identified as high priority in the Department's engagement process. However, Virginia's electric utilities are neither incentivized nor disincentivized to keep fuel costs low, as those costs are directly passed through to customers.<br><br>Under Virginia Code § 56-249.6, the SCC has the authority to review the prudency of fuel costs, with consideration for factors including reliability and cost. Further regulatory oversight and review in this area could help contain utility fuel costs. However, the SCC does not appear to have authority to enact a fuel-cost sharing mechanism. Because fuel cost sharing has sophisticated design requirements, further investigation of this topic may be needed to evaluate design options and determine suitable approaches for Virginia. | *General Assembly:*<br>• Direct the SCC to evaluate utility incentives for fuel cost management, and authorize the SCC to implement fuel cost-sharing mechanisms. |

| Recommendation | Rationale | Responsible Entity |
|---|---|---|
| 3. Incentivize utility alignment with greenhouse gas reduction and energy efficiency targets outlined in the Virginia Clean Economy Act (VCEA). This includes further incentivizing utilities to comply with the renewable portfolio standard (RPS) and to meet energy efficiency targets. In doing so, incorporate strategies that incentivize cost containment. | The VCEA establishes a renewable portfolio standard (RPS) and outlines energy efficiency targets for Virginia's electric IOUs. Virginia's electric IOUs have had varying success in achieving the energy efficiency targets established under the VCEA. Achievement of these targets would help advance progress toward achieving Virginia's affordability, equity, bill management, and environmental goals.<br><br>Additionally, utilities are currently authorized to pass renewable energy credit (REC) costs to customers via RACs. Utilities also receive ROE on the costs of those credits. Under this regulatory structure, utilities lack a financial disincentive for failing to meet annual greenhouse gas reduction targets.<br><br>Further incentivizing attainment (and disincentivizing non-attainment) of RPS and energy efficiency targets while controlling costs would better encourage utilities to achieve the targets established in the VCEA. A focused proceeding may be appropriate to evaluate and update incentives associated with RPS and energy efficiency compliance, which the General Assembly could direct the SCC to initiate. | *General Assembly:*<br>• Direct the SCC to open a proceeding to evaluate utility incentives related to RPS and energy efficiency target compliance. Associated legislation might include statutory updates to remove prescriptive cost recovery features for RPS or other programs, to allow SCC latitude to enact new incentive structures. |
| 4. Implement a limited number of PIMs with incentives for reasonably challenging, but achievable, priority outcomes. This can take place if the SCC elects to expand its use of PIMs through Case No. PUR-2023-00210. If feasible and more effective, updates to energy efficiency incentives (included in Recommendation 3) may be addressed here. | PIMs can effectively promote the achievement of a range of metrics of interest, including both traditional outcomes like reliability and more emergent topics of interest. The SCC already has a comprehensive evaluation of PIMs underway. Upside (reward) PIMs, or symmetric PIMs with reward and penalty, can provide meaningful inducement for utility attention to priority outcomes. A small number of downside-only PIMs can also be considered for core service obligations like reliability and customer service, particularly to serve as a "backstop" if broader PBR with strong cost-containment incentives is enacted (*i.e.*, Recommendation 6). A limited number of total PIMs (*e.g.*, maximum 5) is helpful to focus attention on priority areas and not dilute the incentive. | *SCC:*<br>• Informed by the SCC's ongoing PIMs proceeding in Case No. PUR-2023-00210, implement a select number of PIMs to incentivize utility achievement of desired outcomes. |

| Recommendation | Rationale | Responsible Entity |
|---|---|---|
| 5. Develop an all-source competitive procurement framework to make additional progress toward desired outcomes (including peak demand reduction, cost efficiency, and competitive market outcomes). | All-source competitive procurement approaches enable a technology-neutral process to address emergent load growth and system needs that can yield a more cost-effective resource portfolio than utility-led, technology-specific generation acquisitions. By adopting all-source competitive procurement, the state can add generation and capacity to address load growth, facilitate economic development, and better protect customer affordability. | *General Assembly:*<br>• Direct the SCC to require the use of all-source competitive procurement by utilities for applicable needs identified in resource planning processes, employing best practices identified in this report or other market standards. Consider whether other statutory updates are necessary for resource planning or Certificate of Public Convenience and Necessity (CPCN) requirements to ensure a common approach.<br>*SCC:*<br>• Ensure utility compliance with all-source competitive procurement, via monitoring, review, and approval of results. |
| 6. Iterate upon the existing biennial rate review structure by shifting to a three- to five-year multi-year rate plan (MRP) schedule. Incorporate other PBR mechanisms into the MRP design to achieve an outcome-based, balanced structure, including, for example, decoupling, PIMs, capex-opex equalization, and an updated earnings sharing mechanism (ESM). | Utilities currently submit biennial rate reviews. An MRP with a revenue cap, paired with a range of other PBR and alternative ratemaking tools, would help incentivize cost containment in balance with additional priority outcomes.<br>For the most successful implementation and greatest impact, a comprehensive and effective MRP should be adopted in concert with a range of PBR or alternative regulatory tools, including (but not necessarily limited to) the following:<br>• Decoupling, which can help accomplish revenue stability without the need to rely heavily on RACs<br>• PIMs, which can help promote achievement of identified metrics (described in greater detail in Recommendation 4)<br>• ESMs, which would subject a larger share of utilities' revenues and costs to performance incentives (currently, ESMs can only be applied to certain generation and distribution costs recovered via base | *General Assembly:*<br>• Direct the SCC to open a proceeding to design a PBR structure. Task the SCC to evaluate options and enact a detailed PBR framework that includes consideration of (1) the appropriate duration for an MRP in Virginia, and (2) the appropriate PBR mechanisms and associated design features to incorporate into the MRP. Provide a date by which the new MRP-based PBR system is to be adopted.<br>*SCC:*<br>• Initiate a proceeding that begins with SCC-proposed principles and a possible PBR framework for stakeholder consideration. Manage a |

| Recommendation | Rationale | Responsible Entity |
|---|---|---|
| | rates and cannot be applied to generation and distribution-related costs recovered via RACs)<br>• Tools to reduce or eliminate capex bias<br>• Methods for setting appropriate ROE levels that balance utility financial interests with ratepayer and policy objectives<br>• Other regulatory reforms as discussed in this report or as determined by the SCC to support system needs.<br><br>Initiation of this new MRP structure could take place following the subsequent biennial review periods (*e.g.*, in 2028-2029) to allow time before then to design its primary structures. | set of technical conferences and filings to refine options, seek intervenors' proposals, and manage toward enactment aligned with future rate cases and other system activities. |

# Chapter 3: Technical Report

## 3.1 Summary of the Virginia Department of Energy Stakeholder Process

At the broadest level, PBR combines a set of regulatory mechanisms and processes with an aim to align outcomes with regulatory objectives. This includes the list of PBR and alternative regulatory tools provided in the Joint Resolution and listed above. A regulatory framework is not inherently "performance-based" if it utilizes one or more of these mechanisms. Rather, good incentive regulation emerges when the full suite of regulations is structured to motivate outcome-oriented utility performance that delivers desired results.

The Joint Resolution directs the Department to conduct a stakeholder engagement process to gather perspectives regarding the potential for PBR and alternative regulatory tools in Virginia to inform the SCC's report. The Department held a kickoff meeting in October 2024 and conducted its stakeholder engagement process across eight additional engagement meetings held between December 2024 and April 2025. The process consisted of an extensive written comment period, eight stakeholder engagement meetings, and additional feedback opportunities including an opportunity to complete a regulatory assessment template, focused on evaluating Virginia's existing regulatory framework, and a PBR template, focused on the ways in which PBR or alternative regulatory tools may help achieve the regulatory outcomes identified in the Joint Resolution.

For a detailed overview of topics discussed at each meeting, groups that participated throughout the process, specific stakeholder perspectives on individual topics, presentation materials, etc., please refer directly to the Department's report or to the Department's website dedicated to the PBR stakeholder engagement process (Evaluation of Performance-Based Ratemaking: Stakeholder Process).

### Stakeholder Engagement Themes

Throughout the Department's stakeholder engagement process, participants had several opportunities to provide feedback and share their perspectives related to the performance areas listed in the Joint Resolution and alternative regulatory tools worth exploring. Figure 2 below displays the performance areas that stakeholders elected to consider while conducting an assessment of Virginia's existing electric utility regulatory mechanisms as part of the Department's stakeholder engagement process. The regulatory assessment assignment provided an opportunity for participants to evaluate how Virginia's existing regulatory framework does and/or does not incentivize achievement with the performance areas listed in the Joint Resolution.

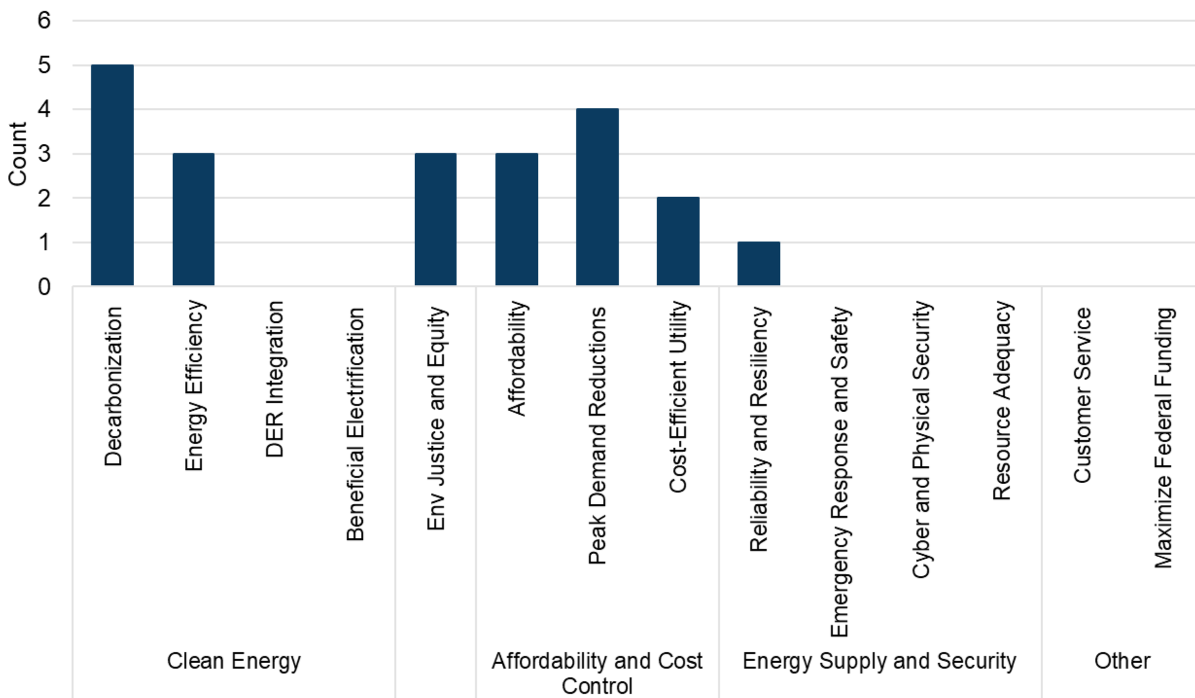
To complete the regulatory assessment, participants were asked to select one of the Joint Resolution performance areas and evaluate the effect that Virginia's existing regulatory mechanisms have on that performance area. The participant responses in Figure 2 show the performance areas that participants elected to evaluate as part of that activity. As displayed in Figure 2, the most popular performance areas for this activity were decarbonization and peak demand reduction.

In practice, identified performance areas interrelate and often affect broader objectives. For example, environmental justice relates to both clean energy concerns and affordability. Affordability, meanwhile, is influenced by numerous utility and system influences large and small. To reflect participants' top thematic areas of concern, Figure 2 displays their selected performance areas grouped according to related items. This reveals some thematic priorities among participants in the Department process:

- Affordability and cost control (nine responses)
  - Affordability (three)
  - Peak demand reductions (four)
  - Cost-efficient utility (two)
- Clean energy (eight responses)
  - Decarbonization (five)
  - Energy efficiency (three
- Environmental justice and equity (three responses)
- Energy supply and security (one response)
  - Reliability and resiliency (one)

These results are consistent with survey results from other points in the Department's stakeholder engagement process (refer directly to the Department's report for further details).[7]

**Figure 2: Key performance areas as identified by respondents during the Department-led stakeholder engagement process**




Source: Replicated from p. 24 of the Department's PBR stakeholder engagement report.

[7] Department's PBR Stakeholder Engagement Report (Part 1 and Part 2).

Note: In addition to the regulatory assessment—the results of which inform this figure—participants had additional opportunities to identify and discuss performance areas of interest via other surveys and homework assignments issued throughout the Department's stakeholder engagement process, and during the meetings themselves. While Figure 2 specifically reflects participants' responses to the regulatory assessment, the responses captured in this figure are broadly representative of perspectives shared throughout the Department's process. For more information, please refer directly to the Department's report.

As discussed in greater detail in the Department's report, participants had opportunities to share perspectives on Virginia's current regulatory structures and what PBR or alternative regulatory tools are worth considering or expanding in Virginia. Additionally, numerous participants expressed concern that Virginia's extensive use of rate adjustment clauses (RACs, sometimes also referred to as "riders" or "trackers") to recover utility costs interferes with some Virginia regulatory objectives, including the ability to improve affordability.

Overall, several participants expressed interest in MRPs, revenue decoupling, and PIMs (with metrics and scorecards) as potential pathways to incent improved performance. Participants emphasized the importance of considering the ways that these tools might operate in combination with one another, rather than in isolation. Some stakeholders in the Department process, including representatives for the IOUs, expressed that they felt that Virginia's existing framework is sufficient to achieve desired outcomes.

This report takes the stakeholder feedback and discussions held in the Department process as input that informs the assessment and review of regulatory reform opportunities. We also provide additional review and analysis—informed by research and experience with available regulatory tools—to provide an independent study in response to Joint Resolution directives.

## 3.2 Current Legislative and Regulatory Context

While the regulatory and legislative history related to electric utility ratemaking in Virginia is extensive, this section aims to briefly summarize current regulatory proceedings and legislative context relevant to alternative regulation and the Joint Resolution. This context informs the report's analysis of regulatory incentives and their performance.

### Relevant Regulatory Proceedings

#### *PUR-2024-00152: In the matter concerning performance-based regulation and alternative regulatory tools for investor-owned electric utilities*

On September 24, 2024, the SCC opened Case No. PUR-2024-00152, *In the matter concerning performance-based regulation and alternative regulatory tools for investor-owned electric utilities*.[8] In its Order Establishing Proceeding, the SCC outlined the directives for the Department and the SCC according to the Joint Resolution, and established a schedule for the proceeding. On December 17, 2024, the SCC issued an Order Modifying Schedule in this

[8] Virginia State Corporation Commission, Order Establishing Proceeding (September 24, 2024), Case No. PUR-2024-00152, *Ex Parte: In the matter concerning performance-based regulation and alternative regulatory tools for investor-owned electric utilities*.

proceeding, modifying the previous schedule and establishing that the Department's report must be filed in the docket on May 9, 2024.

In addition to establishing a schedule for the Department's stakeholder engagement process, the Order Establishing Proceeding also directed SCC Staff to support the Department in identifying and conducting outreach to parties with likely interest in the proceeding and established that there would be an opportunity for public comment on the Department's report.

### *PUR-2023-00210: In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia*

On December 12, 2023, the SCC opened Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia* on December 12, 2023 in response to legislative directives that the SCC "[initiate] a proceeding to review and determine the appropriate protocols and standards applicable to implementing … performance-based adjustments."[9]

In the proceeding, the SCC sought stakeholder perspectives and recommendations regarding potential standards and protocols to consider when implementing a performance-based approach, as required by the legislation. On August 1, 2024, the SCC filed a Staff Report summarizing stakeholder input from the proceeding, outlining potential implementation approaches, and identifying a list of metrics for the SCC to consider requiring utilities to report on.[10] In the report, Staff identified that the SCC could implement performance-based adjustments via a dedicated performance metrics proceeding, or by reviewing relevant performance data within electric utilities' biennial review proceedings, in which the SCC would determine metrics and develop a results scorecard. Staff also identified a number of metrics (some preexisting, some new) for utility performance tracking purposes, including metrics pertaining to reliability, generating plant performance, customer service, and operating efficiency. Staff proposed that some metrics should be tracked on a scorecard, while others should be tracked for informational purposes only.

Following public comments on the Staff report, the SCC issued an order on October 21, 2024, establishing that the Commission would review performance data in utilities' biennial rate review proceedings, and use that data to inform development of appropriate metrics and benchmarks and develop a scorecard, to be applicable starting in utilities' 2027 biennial rate reviews.[11] In its October order, the SCC approved most Staff-recommended metrics and sought public comments on both a list of suggested metrics to be evaluated in utilities' biennial proceedings

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[9] Virginia State Corporation Commission, Order Establishing Proceeding (December 12, 2023), Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia*.

[10] Virginia State Corporation Commission, Staff Report (August 1, 2024), Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia.*

[11] Virginia State Corporation Commission, Order (October 21, 2024), Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia.*

via a scorecard, as well a list of metrics to be provided for informational purposes. The order additionally directed Staff to develop draft proposed regulations for public comment, informed by public comments received on the SCC's order.

On March 7, 2025, Staff filed a list of proposed draft regulations for the SCC to consider, informed by comments in the proceeding.[12] The filing included proposed modifications to Virginia Administrative Code Chapter 204, *Rules Governing Utility Rate Applications and Annual Informational Filings of Investor-Owned Electric Utilities.* On May 30, 2025, the SCC issued an order directing that Staff's list of proposed draft regulations be sent to the Office of the Registrar for publication. A public comment period on the proposed draft regulations closed on July 30, 2025, and the proceeding remains active.[13]

### Legislative Context

Title 12.1 of the Code of Virginia establishes that the SCC "shall have the power and be charged with the duty of regulating the rates, charges, services, and facilities of all public service companies" in Virginia, including but not limited to qualifying electric utilities.[14]

Title 56 of the Code of Virginia establishes Virginia law related to public service companies subject to SCC regulation (including but not necessarily limited to electric utilities).[15] Several chapters within Title 56 define Virginia's electric utility ratemaking procedures, including Chapter 10, *Heat, Light, Power, Water and Other Utility Companies Generally*, which establishes the definition of a public utility in Virginia, and Chapter 23, *Virginia Electric Utility Regulation Act*, summarized in greater detail below.

#### *Virginia Electric Utility Regulation Act*

The Virginia Electric Utility Regulation Act, also known as the "Regulation Act," was signed into law in 2007 and has been substantially modified several times since. In 2007, the Regulation Act established procedures and requirements related to utility rates and earnings, including but not limited to RACs as a means for the utility to recover specified costs outside of base rates and utilities' biennial rate reviews.[16] In accordance with the Regulation Act, the SCC currently regulates utilities through a combination of traditional COSR practices and performance-based or alternative ratemaking practices, as summarized below in Table 3.

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[12] Virginia State Corporation Commission, Attachment A: Proposed Draft Regulations (March 7, 2025), Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia*.

[13] Virginia State Corporation Commission, Order Establishing Rulemaking (May 30, 2025), Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia*.

[14] Virginia Code § 12.1, State Corporation Commission.

[15] Virginia Code Title 56, Public Service Companies.

[16] Dominion's biennial rate reviews are primarily covered in Code § 56-585.1 and APCo's biennial rate reviews are primarily covered in Code § 56-585.8.

Under a pure COSR model, utilities are authorized to recover the prudently accrued costs (*e.g.*, costs associated with a necessary infrastructure project) across their base of customers, with an additional authorized return on equity (ROE). COSR is the core ratemaking framework for electric utilities, with other alternative ratemaking mechanisms also incorporated. Code of Virginia § 56-585.1 and § 56-585.8 directs the SCC to determine a fair ROE applicable to each of Dominion's and APCo's generation and distribution services, and grants the SCC the authority to determine a methodology for determining an ROE that is in the public interest.

The Regulation Act also establishes the following distinction between "Phase I" and "Phase II" utilities, which are subject to slightly different regulatory rules in some instances:[17]

- Phase I Utility: An investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002.
- Phase II Utility: An investor-owned incumbent electric utility that was bound by such a settlement.

Under these definitions, APCo is a Phase I utility and Dominion is a Phase II utility.

**Table 3: Overview of existing electric utility ratemaking mechanisms in Virginia**

| Existing Regulatory Mechanism | Overview |
|---|---|
| **Biennial Rate Reviews** | Virginia's electric IOUs file rate reviews on a biennial basis in accordance with 2023 revisions to the Regulation Act (Code of Virginia Title 56, Ch. 23). Previously, utility rate reviews were conducted on a triennial basis.<br><br>For rate reviews filed prior to 2024, utilities were subject to an earnings "collar" of 70 basis points (bps), which is 0.7 percent above its profit margin. Beyond this threshold, utilities were required to provide a bill credit equaling 85 percent of the earnings above the 70 bps threshold to its customers. However, this collar no longer applied starting in 2024 (see Virginia Code § 56-585.1). |
| **ROE Determinations** | Currently, Dominion and APCo have the following authorized ROE:[b]<br>• Dominion: 9.70 percent<br>• APCo: 9.75 percent<br><br>In March 2025, Dominion requested an ROE increase to 10.4 percent. More details on Dominion's requested ROE adjustment are available in Dominion's biennial review application (see SCC Case No. PUR-2025-00058).[c]<br><br>Utilities are authorized to earn this ROE on any of their RACs except for transmission costs (which are subject to the FERC-approved ROE) and fuel riders. |
| **Earnings Sharing** | Excess earnings by utilities can get returned to customers according to the following criteria:<br>• Dominion: 85 percent of over earning (earning above the allowed ROE) is credited back to customers, for amounts up to 150 bps above the allowed ROE; 100 percent of over earning is credited to customers for any additional amounts greater than the 150 bps threshold (see Virginia Code § 56-585.1). |

[17] Virginia Code § 56-585.1 A 1.

<table>
<tr><th>Existing Regulatory Mechanism</th><th>Overview</th></tr>
<tr><td></td><td><ul><li>APCo: 100 percent of over earning is credited back to customers, for amounts above 100 bps over the allowed ROE (earnings less than 100 bps above the allowed ROE are retained by the utility) (see Virginia Code § 56-585.8).</li></ul></td></tr>
<tr><td>Rate Adjustment Clauses (RACs)</td><td>Code of Virginia § 56-585.1 A 4–6 authorizes electric utilities to petition the SCC annually for approval of RACs for costs related to the following items. Customers pay for RACs on a per-kilowatt or per-kilowatt-hour basis. The list below is for summary purposes only. For full details of all costs eligible for recovery via a RAC, please refer directly to the statute (see Virginia Code § 56-585.1).
<ul>
<li>Transmission-related costs (utilities can earn FERC-approved ROE on transmission-related costs)</li>
<li>Program-related costs (full program implementation or pilot programs) deemed to be in the public interest, including:
<ul><li>Peak shaving programs</li><li>Energy efficiency programs</li><li>Low-income programs</li></ul></li>
<li>RPS compliance costs</li>
<li>Certain costs associated with offshore wind development</li>
<li>Certain costs associated with compliance with state and federal environmental laws and regulations</li>
<li>Distribution system right-of-way vegetation management costs and qualifying facility undergrounding costs</li>
<li>Certain costs associated with the development or modification of generation facilities</li>
<li>Electric distribution grid transformation projects</li>
</ul>
Dominion’s current RACs or “riders” are available on Dominion’s Exhibit of Applicable Riders (residential)[d] and Exhibit of Applicable Riders (business).[e]<br><br>
APCo’s current riders for residential and nonresidential customers are available on APCo’s Select Schedule Charges and Associated Rider Charges.[f]<br><br>
Each individual RAC is evaluated and set in its own SCC proceeding. Current RACs for Dominion and APCo are listed in Figure 14, Virginia RAC proceedings for Dominion and APCo, January 2022–May 2025.</td></tr>
<tr><td>Performance-incentive mechanisms</td><td>PIMs provide a financial reward (or penalty) to the utility based on measurable performance on an identified outcome. PIMs consist of a metric, a target, and a financial incentive. Metrics are specific, quantifiable measures used to assess a utility's performance in achieving a outcome.<br>
Virginia currently tracks utility performance across the following metrics. This list does not include additional SCC Staff-proposed metrics and targets for consideration in Case No. PUR-2023-00210:[g]
<table>
<tr><th>Metric</th><th>Benchmark/Point of Comparison</th></tr>
<tr><td>Reliability</td><td></td></tr>
<tr><td>System Average Interruption Duration Index (SAIDI) (excluding Major Events)</td><td>Historical comparison<br>Benchmark against peer electric utilities</td></tr>
<tr><td>System Average Interruption Frequency Index (SAIFI) (excluding Major Events)</td><td>Historical comparison<br>Benchmark against peer electric utilities</td></tr>
<tr><td>Generating Plant Performance</td><td></td></tr>
<tr><td>Equivalent Forced Outage Rate on Demand (EFORd) (non-nuclear)</td><td>PJM and NERC standards</td></tr>
</table></td></tr>
</table>

| Existing Regulatory Mechanism | Overview | |
|---|---|---|
| | Equivalent Forced Outage Rate on Demand Excluding Outages Designated Outside Management Control (XEFORd) (non-nuclear) | PJM and NERC standards |
| | Net Capacity Factor (NCF) (nuclear) | Nuclear industry standards |
| | Equivalent Availability Factor (EAF) (Fossil Fuel) | PJM standards |
| | Heat rates (Coal and Combined Cycle) | National average for coal and combined cycle facilities |
| | Capacity Factor (Renewables) | Historical comparison |
| | *Customer Service* | |
| | Average Speed of Answer (ASA) | Historical comparison |
| | Average monthly bills (by rate class) | Benchmark against peer electric utilities |
| | *Rate Competitiveness* | |
| | Revenue per kWh (by rate class) | Benchmark against peer electric utilities |
| | Total aggregated revenues | Benchmark against annual increases in the US Average Consumer Price Index |
| | *Operations & Maintenance Production Efficiency* | |
| | Operations & maintenance efficiency (percent of total assets) | Benchmark against peer electric utilities |
| | Large coal plant production costs | Benchmark against peer electric utilities |
| | Combined cycle plant production costs | Benchmark against peer electric utilities |
| | *Energy Efficiency/RPS Compliance* | |
| | Energy Efficiency Targets | Targets established under § 56-596.2 (see Table 4 below for details) |
| | RPS Targets | Total electric energy sold |
| **Energy efficiency (savings) target** | VCEA § 56-596.2 establishes energy efficiency targets for Phase I and Phase II utilities (see Virginia Code § 56-596.2). These targets are provided below in Table 4. | |
| **Integrated Resource Plans (IRPs)** | Title 56, *Public Service Companies*, Chapter 24, *Electric Utility Integrated Resource Planning* establishes the integrated resource planning (IRP) requirements for Virginia's regulated electric utilities. Although rates are not set via the IRP process, the IRP provides high-level direction regarding the types of investments that electric utilities will likely pursue to meet projected load, ensure reliability, and comply with necessary laws and regulations over a 15-year planning horizon. These investments, if approved, have rate and affordability implications. If a utility seeks to build its own electricity generation resources to serve the increased load projected in its IRP (or build or significantly modify other large energy-related infrastructure projects, such as transmission facilities), it would first need to receive approval to do so from the SCC through a Certificate of Public Convenience and Necessity (CPCN) proceeding. | |

Sources:

[b] S&P Global, *Rate Case Statistics Details* (New York, NY), accessed May 19, 2025.

[c] Virginia Electric and Power Company (Dominion) filing, *Application of Virginia Electric and Power Company for a 2025 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia* (March 31, 2025), Case No. PUR-2025-00058.

[d] "Residential Rates," Dominion Energy (website), accessed July 24, 2024.

[e] "Business Rates," Dominion Energy (website), accessed July 24, 2024.

[f] Appalachian Power Company (APCo), *Select Schedule Charges and Associated Rider Charges*, January 1, 2025.

[g] SCC Division of Public Utility Regulation, "PUR-2024-00152: HJ 30 and SJ 47 Performance-based Regulation Stakeholder Workgroup, SCC PBR Overview," Presentation from SCC Staff during the Virginia Department of Energy's Performance Based Regulation Stakeholder Engagement Process (December 9, 2024); SCC Division of Public Utility Regulation, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia*, Case No. PUR-2023-00210, Order Establishing Rulemaking (May 30, 2025)

In addition to the electric utility regulatory mechanisms listed above in Table 3, Virginia implements revenue decoupling for natural gas service, in accordance with the Natural Gas Conservation and Ratemaking Efficiency Act (Code of Virginia Title 56, Chapter 25). The Act authorizes natural gas utilities to develop "natural gas conservation and ratemaking efficiency plans" (more commonly referred to as "CARE plans") for SCC review and approval. The plans must "promote the wise use of natural gas and natural gas infrastructure through the development of alternative rate designs and other mechanisms that more closely align the interests of natural gas utilities, their customers, and the Commonwealth generally, and improve the efficiency of ratemaking to more closely reflect the dynamic nature of the natural gas market, the economy, and public policy regarding conservation and energy efficiency."[18]

If a gas utility elects to file a plan, the plan must include several gas conservation and ratemaking efficiency mechanisms, including (but not limited to) weather normalization and decoupling mechanisms. Electric utilities in Virginia are not currently subject to revenue decoupling.

### *Virginia Clean Economy Act*

The Virginia Clean Economy Act (VCEA), codified as Chapter 1193 of the Virginia Acts of Assembly (2020 Session), formally established a number of decarbonization-related goals and that energy efficiency and renewable resources are in the public interest in the Commonwealth. Broadly, the VCEA seeks to reduce Virginia's greenhouse gas emissions. Key standards relevant to utility operations are summarized below in Table 4, though the VCEA establishes additional requirements beyond those listed in the table, related to other topics.

**Table 4: RPS and energy efficiency standards established under the VCEA**

| VCEA Requirement | Applicable VCEA Statute | Target |
|---|---|---|
| **Mandatory RPS Program.** Phase I and II utilities' electricity portfolios must consist of certain percentages of RPS-eligible resources by dates established in VCEA. | Virginia Code § 56-585.5. Generation of electricity from renewable and zero carbon sources. | APCo:<br>• 80% by 2045<br>• 100% by 2050<br>Dominion:<br>• 100% by 2045 |
| **Mandatory energy efficiency program.** Phase I and II utilities must develop energy efficiency programs to achieve specified energy | Virginia Code § 56-596.2. Energy efficiency programs; financial assistance for low-income customers. | Energy savings targets by utility, compared to 2019 baseline year:<br>**APCo** / **Dominion**<br>0.5% by 2022 / 1.25% by 2022<br>1.0% by 2023 / 2.5% by 2023 |

[18] Virginia Code § 56-601 A.

| VCEA Requirement | Applicable VCEA Statute | Target | |
|---|---|---|---|
| conservation targets (compared to a 2019 baseline year). | | 1.5% by 2024<br>2.0% by 2025<br>3.0% by 2026<br>3.5% by 2027<br>4.0% by 2028 | 3.75% by 2024<br>5.0% by 2025<br>3.0% by 2026<br>4.0% by 2027<br>5.0% by 2028 |

In addition to the energy efficiency standards and RPS program, the VCEA contains provisions intended to improve grid reliability and security, enhance the distribution grid, expand renewable and storage deployment (including but not limited to DERs), reduce peak demand, and work toward decarbonization, consistent with many of the performance areas outlined in the Joint Resolution.

## 3.3 Analysis of Electric Utility Performance Under Virginia's Current Regulatory Construct

This section reviews the recent performance and outlook for Dominion and APCo under Virginia's existing regulatory structure.

### Primary Observations

Electricity retail rates in Virginia are competitive with national averages; however, prices are trending up and risk further increases as a result of planned utility investments. This trend points to an affordability challenge that is likely to accelerate in the years ahead. Existing ratemaking structures may not sufficiently encourage utility cost containment in a manner that promotes prudent utility decision-making aligned with regulatory and policy objectives. This is due to inherent limitations of traditional COSR ratemaking, including that COSR incentivizes utilities to maximize self-owned projects and capital investments ("capex bias") and that COSR has a tendency to reduce revenue uncertainty where possible through true-ups or automatic adjustments.

Virginia's regulatory construct employs an unusually high reliance on RACs compared to the use of cost trackers or riders in other states. The expanded use of RACs over years has significantly de-risked utility revenues and earning opportunities while siloing investment and cost categories in a manner that limits the utilities' ability to strategically manage the enterprise on a whole-system basis. Virginia also displays a high degree of ratemaking via legislative design. That includes instances in which precise details regarding ratemaking structures are prescribed in statute rather than delegated to the authority of state regulators, as is more common elsewhere in the US. This might have the effect of limiting the SCC's regulatory discretion in ratemaking decisions. It may also limit opportunities to evaluate how different ratemaking structures interact and can be applied to achieve desired outcomes system-wide and over longer time frames.

Virginia electric utility regulations include some limited performance-based mechanisms, as defined or authorized in statute. While these offer opportunities to incentivize key outcomes, they are narrowly constructed and are not always utilized. Opportunities exist to refine and expand these mechanisms, or possibly to pursue implementation of a more comprehensive

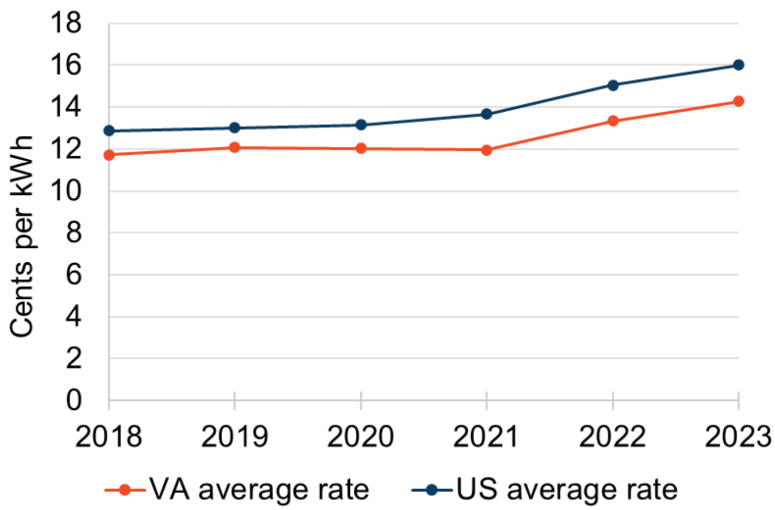
PBR framework that would tackle cost containment and other regulatory outcomes on a broader scale.

The remainder of this section expands upon these and other themes.

### Virginia Electricity Rates

Virginia electricity rates are fairly competitive with average rates nationwide and, similarly, reflect an upward trend (see Figure 3). This increase in electricity rates is not unique to Virginia—it is common among electric utilities nationwide. But it presents an affordability challenge to customers and the broader economy that depends on electricity. In 2023, Virginia's average residential electricity rate was 11 percent lower than the US average. From 2018 to 2023, residential electricity rates in Virginia increased by approximately 22 percent. Over the same period, average US residential rates increased by approximately 24 percent.

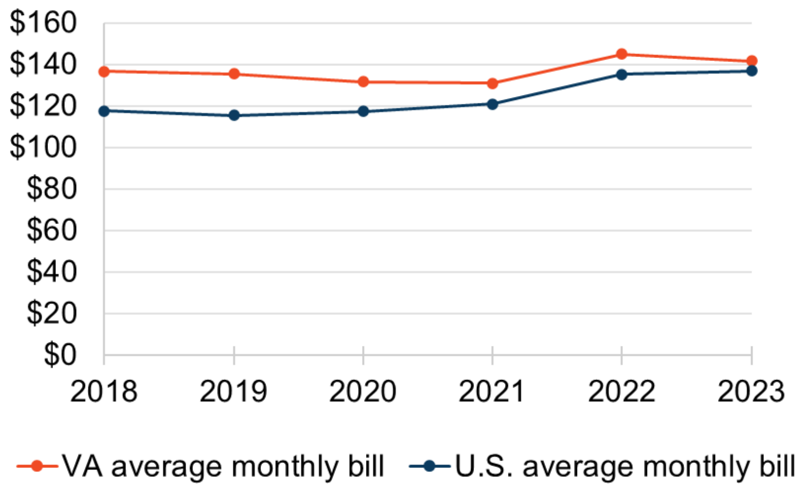
**Figure 3: Average retail residential rate, Virginia and US (2018-2023)**




Source: "Electric Sales, Revenue, and Average Price" (Table 4, January 2018–January 2023), US Energy Information Administration, accessed July 24, 2025. Figure by CEG and GPI with assistance from PNNL.

The average bill for Virginia residential electricity customers—which reflects total volume of electricity consumed as well as additional costs and charges—tells a similar story (see Figure 4). In 2023, the average monthly residential bill in Virginia was $141.63, which is 3.5 percent higher than the US average of $136.84. However, electricity bills in Virginia have increased at a lower rate than bills nationally. The average residential monthly bill in Virginia increased by 3.7 percent from 2018 to 2023, while the average US residential monthly bill increased by 16.3 percent over the same period.

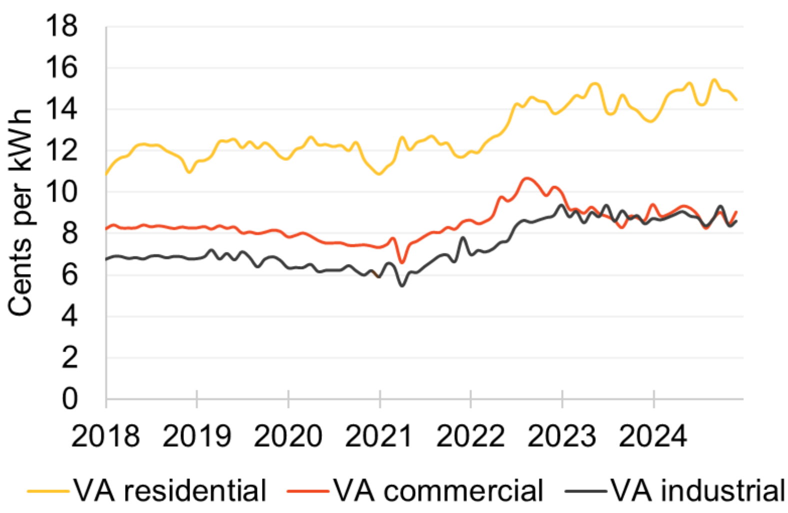
**Figure 4: Average monthly residential electricity bill, Virginia and US (2018–2023)**




Source: "Electric Sales, Revenue, and Average Price" (Table 5a, January 2018–January 2023), US Energy Information Administration, accessed July 24, 2025. Figure by CEG and GPI with assistance from PNNL.

As displayed below in Figure 5, commercial and industrial rates in Virginia are currently lower than residential rates. From 2018 to 2022, commercial rates were consistently higher than industrial rates, but beginning in 2023, the difference between these two rate classes narrowed and are now roughly equivalent. In addition, the difference between residential rates compared to both commercial and industrial rates has increased in recent years. From January 2023 to December 2024, Virginia's average residential rate increased by 3.6 percent while the average commercial rate decreased by 9.4 percent.

**Figure 5: Electricity rates by customer class, Virginia (2018–2024)**



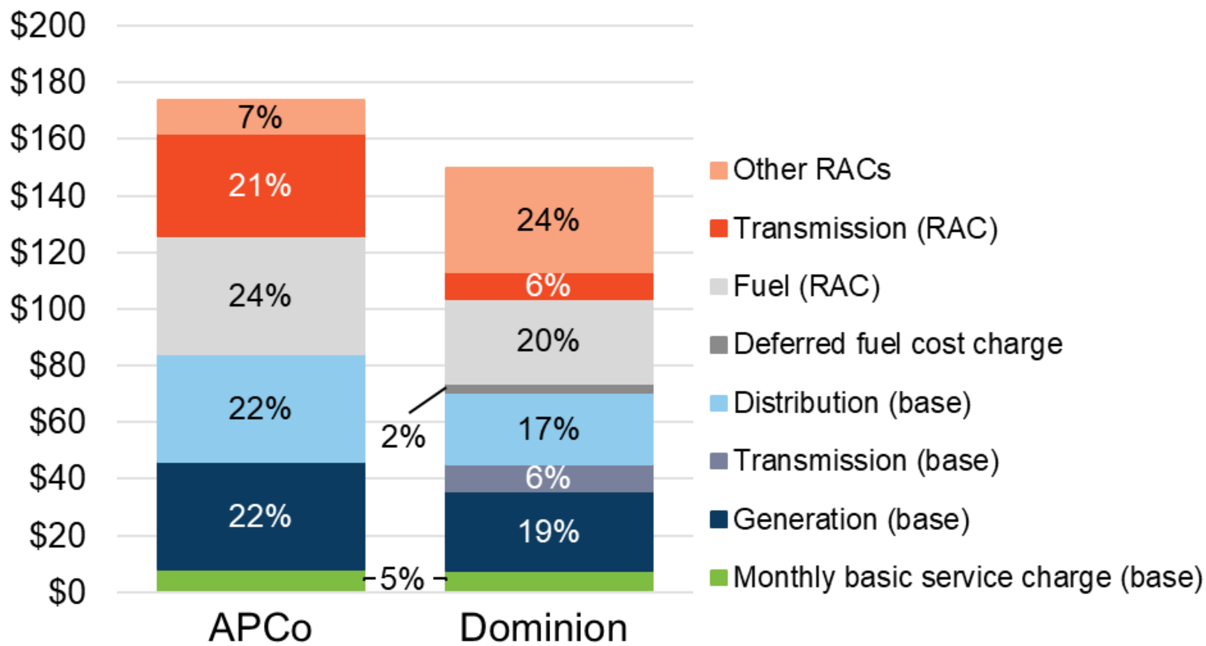

Source: "5.6 Average retail price of electricity to ultimate customers by end use sector, by state," *Electricity Data Browser* (January 2018–December 2024), US Energy Information Administration, accessed July 24, 2025. Figure by CEG and GPI with assistance from PNNL.

### Composition of Rates

Trends in total electricity prices are important; however, they can mask the underlying composition of utility cost, as well as what incentives may exist for utility cost control, policy achievement, and other outcomes.

Figure 6 shows the primary rate components for Dominion and APCo in 2025 for a typical residential customer that consumes about 1,000 kWh per month. This representative customer pays about $174 per month in the APCo territory, compared to about $150 per month for Dominion. For both utilities, rates are composed of multiple cost components, including distribution and transmission system expenses, electricity generation costs, fuel costs, and other rate adjustment clauses (RACs). In Dominion's case, a relatively larger portion of costs are contained in this "other RACs" category of expense. For APCo, fuel constitutes the largest cost component, although generation, transmission, and distribution costs are all comparable.

**Figure 6: Cost components of a typical monthly residential electricity bill in Virginia (1,000 kWh consumption) in 2025[a, b]**




Sources: Appalachian Power Company, [Select Schedule Charges and Associated Rider Charges](), January 1, 2025; Dominion Energy, [Schedule 1 Residential Service,]() August 4, 2024. Figure by GPI and CEG with assistance from PNNL.

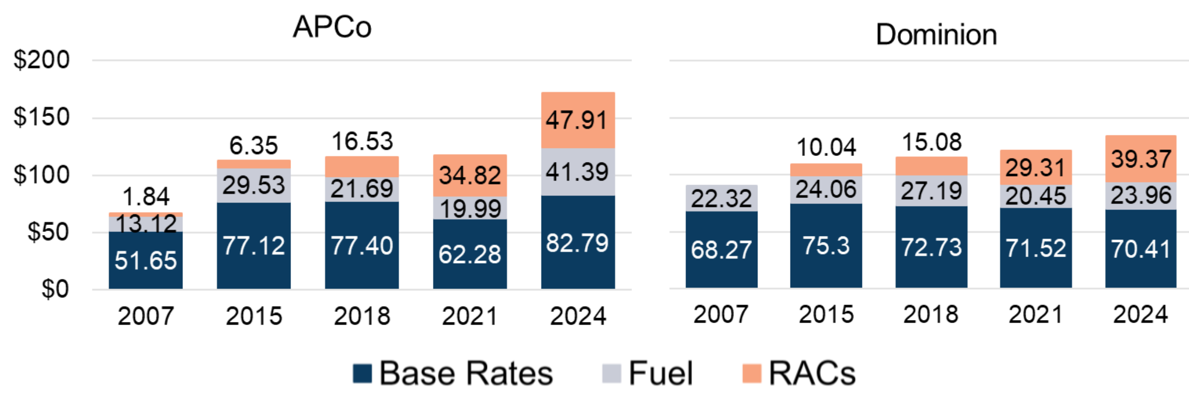
Notes:

a. For APCo and Dominion, many rate components are treated as independent RACs outside of utility base rates. These include transmission costs, composed in large part from FERC-regulated formula rates, and fuel costs considered to be a pass-through to customers. In this chart, rates are decomposed into their common categories of distribution, generation, transmission, and fuel costs to identify a familiar set of cost components for electricity rates, as well as "other" RACs to aggregate additional costs recovered on the utility bill. Dominion collects transmission costs through both a base charge and a RAC. APCo appears to collect all transmission costs through a RAC.

b. Dominion Energy Schedule 1 is composed of a two-part graduated rate, in which the first 800 kWh of monthly consumption receive a higher distribution rate than consumption above 800 kWh. Generation costs also vary by season, with costs in June–September being slightly higher for the first 800 kWh than in October–May, and significantly higher in the summer months for all electricity consumed above 800 kWh. Rates shown for Dominion reflect a weighted average for two-thirds winter rate and one-third summer rate and reflect the two-tier structure.

Over time, different rate components present different trends. Figure 7 below shows the composition of rates (base rates, fuel costs, and RACs) for each IOU at various points since 2007. Base rates include the primary capital costs associated with maintaining the generation and distribution infrastructure of each utility. These are the primary focus of rate case reviews and rate setting. Fuel costs are a pass-through expense for amounts spent by each utility to fuel its utility-owned and -operated generating fleets (largely composed of coal and natural gas costs). Fuel cost is treated as an operating expense, and thus is not eligible for a rate of return, nor is it subject to meaningful cost-containment incentives. The remainder of costs are contained in nonfuel RACs.

**Figure 7: Historical cost components of typical monthly residential electricity bill in Virginia (1,000 kWh consumption, summer month)**




Source: Recreated from Commonwealth of Virginia State Corporation Commission, *Status Report: Implementation of the Virginia Electric Utility Regulation Act*, November 1, 2024.

Note: From January 1, 2017, to December 31, 2019, APCo was under a "transitional rate period" in accordance with Virginia Code § 56-585.1:1, which functioned as a temporary rate freeze. Dominion was under a separate transitional rate period from January 1, 2017, to December 31, 2020. As established in Virginia Code § 56-585.1:1, the SCC may not conduct a biennial rate review during the transitional rate period for either utility but is still responsible for reviewing fuel recovery and purchased power costs. Following the transitional rate period, rate reviews for APCo recommenced in 2020, utilizing the prior three 12-month test periods (2017, 2018, and 2019). Rate reviews for Dominion recommenced in 2021, utilizing the prior four 12-month test periods (2017, 2018, 2019, and 2020). For further details, please refer directly to Virginia Code § 56-585.1:1.

As Figure 7 illustrates, both utilities have had relatively stable base rates, at least since 2015. APCo base rates grew significantly between 2007 and 2015 then stabilized, while Dominion base rates are almost unchanged. Fuel costs reflect changes in market prices and other factors, including a significant increase in recent years. This recent increase is attributable in part to inflationary pressures, as well as recent global geopolitical conflicts. RACs, meanwhile, have increased dramatically over this period for both utilities.

In practice, this increase in the RAC cost component has the effect of shifting a proportionally larger share of utility costs—and associated revenue—into what are predominantly "trackers" with automatic adjustments. This has moved what would otherwise be recovered in base rates to something more like pass-through expenses with greater revenue stability and low risk of under-recovery. Nonetheless, many of the RACs receive a rate of return, more like a rate-based capitalized expense than a pass-through operating expense like fuel costs. This creates a “best of both worlds” scenario for utility cost recovery and earning in which these costs receive a regulated return, or profit, while that revenue and associated earning is substantially de-risked through a mechanism designed for revenue assurance.

Fuel costs and RACs are both discussed in more detail below in this section, as well as elsewhere in the report to consider performance-based remedies to encourage cost containment and alignment with other objectives.

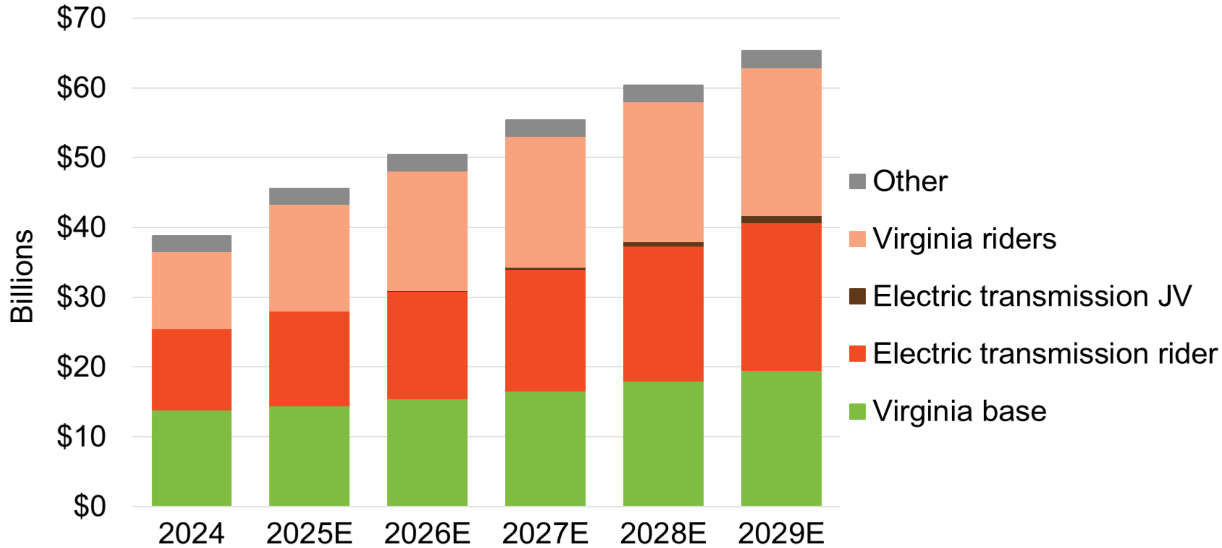
### Future Capital Spending

Although Virginia electricity prices have historically been competitive and relatively low, an affordability challenge is building and looms larger in the years ahead. These patterns track with similar trends experienced in peer jurisdictions across the US, as utilities across the country propose large capital expansion plans to manage compounding factors including deferred infrastructure investment, grid modernization needs, clean energy policies, and broader inflationary pressures.

Likely increases to customer rates are evident in Dominion’s published capital plans, in which its total Virginia rate base is forecast to increase by approximately 68 percent from 2024 to 2029.[19] In its expansion plan, Dominion forecasts numerous categories of capital expense, including transmission and distribution as well as increased investments in renewable energy. Dominion also anticipates growth in RACs. Figure 8 below displays common categories of utility investment, including transmission investment that may be collected via one or more RACs. The pronounced increase in “Virginia riders” is also notable because these reflect a range of costs that are expected to be recovered through various RACs as well.

[19] Dominion Energy, “Q4 2024 Earnings Call,” February 12, 2024, p. 48. Excludes Dominion rate base allocated to North Carolina jurisdiction customers.

**Figure 8: Anticipated growth in Dominion's rate base, by category**




Source: Dominion Energy, "Q4 2024 Earnings Call," February 12, 2025, p. 48.

The review in this section provides a limited snapshot of anticipated capital spending and is mainly limited to Dominion. But the general trends and stairstep increases are consistent across the utility sector. Additional factors will determine the ultimate rates and total bills paid by customers, including fuel costs and total energy consumption by users, but in general, the forecasted increase in capital expenditures will be directly borne by customers as a commensurate increase to their electricity bill. In many cases, those investments are necessary upgrades and expansions to the power system, which will lead to rate increases. Consequently, regulations need to encourage cost efficiency to dampen rate increases to a manageable level. In light of this outlook, it is imperative that regulations have appropriate monitoring and controls in place to support prudent investment decisions as well as serious consideration of alternative solutions.

## Achievement of Select Other Outcomes

The following subsections review a select set of utility performance areas identified in the Joint Resolution, which are considered core responsibilities or policy requirements and can be subject to regulatory incentives: reliability, energy efficiency, and decarbonization and RPS achievement. It is not feasible to make an exhaustive evaluation of all performance areas here due to lack of easily identifiable performance data, among other limitations, but this review provides a lens into priority concerns that Virginia stakeholders have raised for attention.

### *Reliability*

Reliability is among a utility's core service responsibilities, along with affordable and safe electricity service to customers. APCo and Dominion both report annual "blue-sky"[20] SAIDI and SAIFI performance to the SCC, which in turn reports on reliability to the Virginia Legislature.[21] The utilities also report their SAIDI, SAIFI, and CAIDI performance—with and without major event days (MEDs)—to the US Energy Information Administration for its Annual Electric Power Industry Report (see Table 5 below). Currently, there are no public goals, mandates, or targets for the utilities' reliability performance. However, SAIDI, SAIFI, and CAIDI metrics are used to track performance and can inform funding decisions for vegetation management, worst-performing circuits, or strategic underground programs.[22]

As displayed below in Figures 9–11, which provide data on SAIDI, SAIFI, and CAIDI by utility, Dominion's reliability performance is commensurate with national IOU averages, whereas APCo's reliability performance is not. APCo faces more service territory-specific challenges to reliability, however, because its service territory is mountainous and rural, whereas Dominion's is generally flatter, urban and suburban, and customer-dense.[23]

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[20] "Blue-sky" refers to the indices omitting major weather-related events, known as major event days (MEDs) in other jurisdictions, such as hurricanes and derechos.

[21] Virginia State Corporation Commission, *Combined Reports of the State Corporation Commission*, (December 1, 2024), p. 5.

[22] Virginia State Corporation Commission, *Combined Reports*, p. 5.

[23] Virginia State Corporation Commission, *Combined Reports,* p. 6–7.

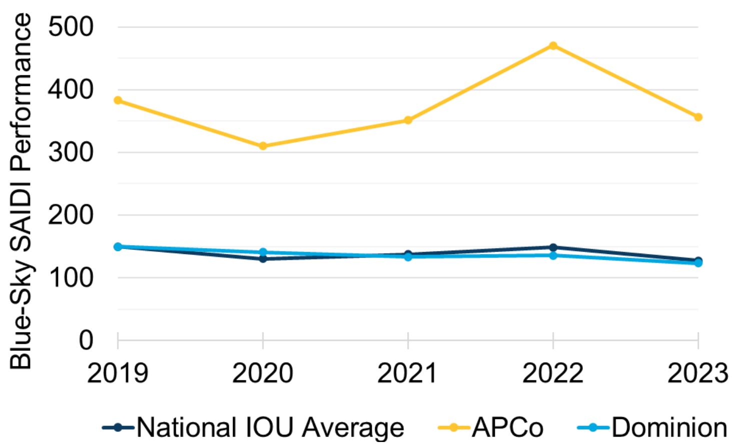
**Table 5: Utility SAIDI, SAIFI, and CAIDI (without MED) compared with national IOU average**

| | SAIDI | | | SAIFI | | | CAIDI | | |
|---|---|---|---|---|---|---|---|---|---|
| | National Average | APCo | Dominion | National Average | APCo | Dominion | National Average | APCo | Dominion |
| **2019** | 149.98 | 382.90 | 149.87 | 1.18 | 1.71 | 1.24 | 122.84 | 224.58 | 120.48 |
| **2020** | 130.46 | 310.20 | 140.99 | 1.12 | 1.51 | 1.26 | 114.86 | 205.43 | 111.90 |
| **2021** | 137.60 | 351.30 | 133.60 | 1.08 | 1.46 | 1.16 | 119.56 | 240.78 | 114.98 |
| **2022** | 148.68 | 470.60 | 136.05 | 1.17 | 1.80 | 1.20 | 120.47 | 261.88 | 153.47 |
| **2023** | 127.78 | 356.60 | 123.32 | 1.04 | 1.53 | 1.17 | 117.48 | 233.84 | 105.86 |

Source: US Energy Information Administration, *Form-861*, 2020-2023.

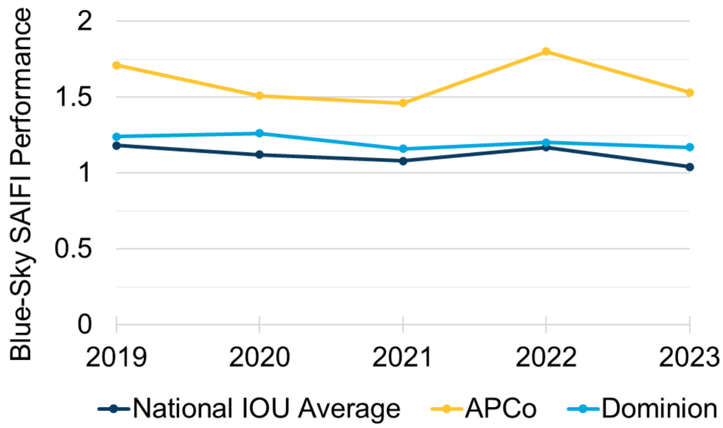
Note: SAIDI is defined as the average outage duration for each customer served. SAIFI is defined as the average number of service interruptions experienced per customer. CAIDI is defined as SAIDI divided by SAIFI, to measure the average duration of power interruptions experienced by customers who have experienced one or more outages.

**Figure 9: Utility SAIDI (without MED) compared with national IOU average**



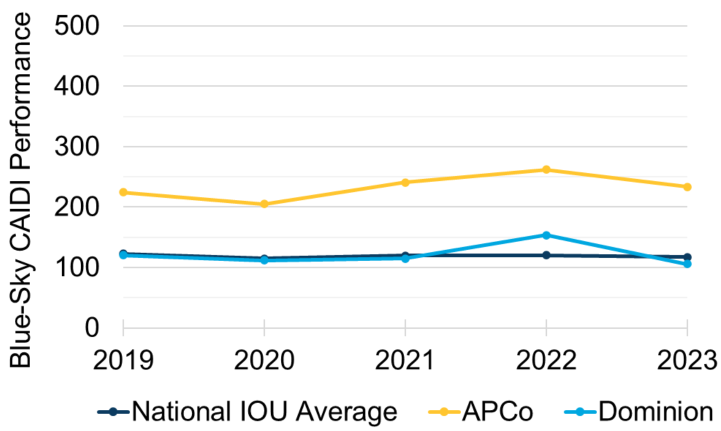

Source: Data from US Energy Information Administration, *Form-861*, 2019-2023, updated October 10, 2024.

**Figure 10: Utility SAIFI (without MED) compared with national IOU average**




Source: Data from US Energy Information Administration, *Form-861*, 2019-2023, updated October 10, 2024.

**Figure 11: Utility CAIDI (without MED) compared with national IOU average**




Source: Data from US Energy Information Administration, *Form-861*, 2019-2023, updated October 10, 2024.

Both APCo and Dominion have reported steady reliability (SAIDI, SAIFI, and CAIDI) performance in recent years. Virginia's reliability could be challenged in the future, however, as climate pressures, aging infrastructure, and demand growth strain regional infrastructure.

For example, Virginia utilities purchase external energy through the PJM capacity market, which targets a reserve margin (the percentage of additional capacity above forecasted peak load to ensure reliability across the PJM market) to protect against system blackouts.[24] PJM's reserve margin is expected to shrink in the coming years because new generation may not sufficiently

[24] "2024 in Review: PJM Markets Adapting for Energy Transition," PJM Inside Lines, January 6, 2025.

meet retirements and demand growth.[25] Recent PJM studies find that the construction and interconnection of new (primarily renewable) energy resources matches previously projected “Low New Entry” scenarios, which indicate that the PJM market may not meet projected peak loads by 2028.[26] This PJM-wide issue is especially relevant for Virginia’s growing energy economy, where data center demand is projected to increase by 1.4 GW by 2027 and population is projected to increase by 500,000 residents by 2030.[27] These cumulative pressures will strain Virginia’s electricity system and the utilities’ efforts to maintain or improve reliability.

To counteract these known challenges, Virginia can consider incentives to maintain or improve reliability performance in balance with other utility and Commission priorities. Some options are described in the performance mechanism discussion in Section 3.4, *Detailed Overview of Performance-based and Alternative Regulatory Tools*.

### *Energy Efficiency*

As described above in Section 3.2, *Current Legislative and Regulatory Context*, the VCEA sets energy efficiency targets for both large IOUs. The targets are set on an annual basis as a percentage of total sales to be reduced below 2019 levels, with the target reduction increasing in each year. Dominion’s target grew from 1.25 percent in 2022 to 5 percent in 2025, while APCo’s grew from 0.50 percent to 2 percent over that same time frame. As previously displayed in Table 4, the IOUs have updated energy efficiency targets for the coming years. Dominion’s energy efficiency targets have been reduced to 3 percent in 2026, 4 percent in 2027, and return to 5 percent in 2028, while APCo’s new energy efficiency targets are 3 percent in 2026, 3.5 percent in 2027, and 4 percent in 2028.[28]

Virginia IOUs are eligible to earn additional profit, or margin, for achievement at or above the annual targets, in an amount equal to additional allowed ROE on the operating expense for the energy efficiency program. A further 20 basis points are added to the allowed ROE for each 0.1 percent of savings achieved above the target, up to a maximum adder of 10 percent of the utility’s total energy efficiency program spending for the year.[29]

As shown below in Figure 12, Dominion has underachieved against its targets, while APCo achieved savings above its targets. In recognition of this performance, APCo received an earnings margin on operating expense associated with its energy efficiency program management in 2022.

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[25] Virginia Electric and Power Company (Dominion) filing, *2024 Virginia Integrated Resource Plan*, Case No. PUR-2024-00184. p. 16-17.

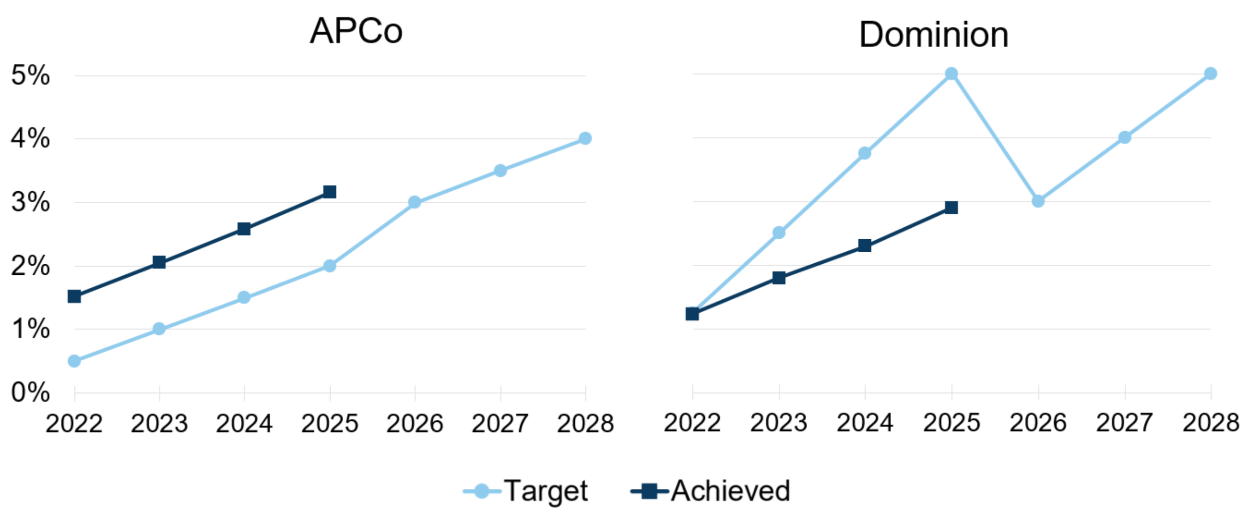
[26] Dominion’s *2024 Virginia Integrated Resource Plan*.

[27] Newmark, *2023 U.S. Data Center Market Overview & Market Cluster* (January 2024). p. 8,: https://www.nmrk.com/insights/market-report/2023-u-s-data-center-market-overview-market-clusters; “New Virginia Population Projections for 2030-205,” University of Virginia Weldon Cooper Center for Public Service, September 6, 2023, https://www.coopercenter.org/research/new-virginia-population-projections-2030-2050.

[28] Virginia Code § 56-596.2.

[29] Virginia Code § 56-585.1.

**Figure 12: Utility achievement of DSM targets in Virginia**




Source: Virginia State Corporation Commission, *Status Report: Implementation of the Virginia Electric Utility Regulation Act*, November 1, 2024.

Many stakeholders in the Department-led process expressed strong interest in improving energy efficiency outcomes in Virginia in support of affordability, equity, bill management, and environmental outcomes (see Figure 2, *Key performance areas as identified by respondents during Department-led stakeholder engagement process*). While the existing performance incentive for energy efficiency attainment is supportive to these interests, it does not appear to induce performance in line with stakeholder interests and VCEA objectives. Virginia can consider updates to the DSM performance incentives as well as other reforms that are identified later in this report.

### *Decarbonization and RPS Achievement*

APCo and Dominion are obligated to procure renewable energy in fulfillment of RPS requirements under the VCEA as described in Section 3.2, *Current Legislative and Regulatory Context*. These prescribe annual attainment levels, which, in brief, require APCo to obtain 14 percent renewable energy in 2025, increasing to 100 percent by 2050, and Dominion to obtain 26 percent renewable energy in 2025, increasing to 100 percent by 2045.[30]

Review of associated statutes and relevant SCC proceedings reveals that RPS attainment in Virginia may function mainly as an economic procurement activity and accounting exercise, detached from the actual resource supply mix. In particular, the utilities are obligated to obtain renewable energy credits (RECs), which can be sourced from generation by utility-owned resources, from RECs associated with purchased power, or purchased as a credit on the open REC market. In this manner, RECs can be used to achieve RPS percentage targets without

[30] Virginia Code § 56-596.2.

necessarily reflecting a reduction in greenhouse gas-emitting generation. The VCEA contains separate requirements for retirement of all utility-owned fossil generation resources by 2045, which, in theory, should provide complementary support for actual reductions in greenhouse gases. However, that requirement does not necessarily produce direct greenhouse gas reductions in the intervening years. In fact, in its 2024 IRP, Dominion indicated that it does not plan to retire any power plants before 2045, while it seeks to add natural gas fired generation to serve load growth.[31]

The REC-based RPS structure in Virginia also demonstrates little incentive for the utilities to pursue cost-effective RPS attainment. RPS costs appear to function entirely as a pass-through to customers, in the form of a collection of RACs, while the utilities also appear to earn a return on equity for the costs of RECs or purchased power they obtain. As will be discussed in the next section on RACs, this structure not only de-risks utility investment decisions while removing the utility's self-interest in cost management, but in fact creates a profit advantage as costs rise. Arguably, this profit opportunity provides a helpful incentive to achieve full RPS compliance; however, it is overshadowed by other deficiencies including the lack of direct decarbonization and lack of cost control incentive. Meanwhile, there is no disincentive (*e.g.*, penalty) to utilities for noncompliance or underachievement of annual RPS targets because deficiencies are collected as a pass-through from customers at a rate of $45 per MWh.

In practice, Dominion's RPS-related costs have increased significantly in recent years, while APCo's have been more modest. Dominion filed a request in December 2024 in the Rider RPS RAC proceeding to collect $608.7 million for the year, effective in September 2025.[32] This is an increase of more than $250 million over the previous year, or an almost $3.00 per month increase for a typical residential customer.[33] APCo, meanwhile, was granted an RPS revenue

[31] Dominion's 2024 Virginia Integrated Resource Plan. In March 2025, Dominion filed a CPCN application to construct the Chesterfield Energy Reliability Center. As proposed, the 944 MW Chesterfield Energy Reliability Center would add four natural gas-fired turbines to an existing facility (and would be hydrogen-natural gas blend capable). The additional turbines would occupy the footprint of a now-retired coal generation unit, and would accompany two existing gas-fired combined cycle units at the site (see Part 1 of Dominion's CPCN application for this facility). For more information, please refer directly to Case No. PUR-2025-00037, *Application of Virginia Electric and Power Company, For approval or a certificate of public convenience and necessity to construct and operate the proposed Chesterfield Energy Reliability Center electric generation and related transmission facilities pursuant to § 56-580 D and 56- 46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider CERC, under § 56-585.1A 6 of the Code of Virginia*.

[32] While this analysis is limited to the RPS rider, Dominion's recovery of RPS-related costs appears to take place across at least three different RACs: rider CE (clean energy), rider OSW (offshore wind), and rider RPS. A fourth RPS-related rider—rider PPA—was consolidated with CE in 2024.

[33] Bryan D. Stogdale, Report of Bryan D. Stogdale, Hearing Examiner (June 2, 2025), Case No. PUR-2024-00215, *Petition of Virginia Electric and Power Company for revision of a rate adjustment clause, designated Rider RPS, under § 56-585.1 A 5 d of the Code of Virginia for the Rate Year commencing September 1, 2025*.

requirement of $16.5 million for the year ending October 2025, or an approximately $0.05 per month increase for a typical residential customer over the previous year.[34]

Costs for RPS attainment, as well as related investments for a transition to a clean grid, are a chief concern of some stakeholders and energy customers in Virginia. As evidenced by increasing electricity rates, which include costs tied to the RPS and other RACs associated with clean energy supply, there are undeniable costs for clean energy procurement and grid investments. However, the review of underlying rate structures reveals that attention is needed on the embedded regulatory incentives and cost recovery structures that govern how these investments get paid for. Considering the principal objectives contained in the VCEA, including the state policy imperative to decarbonize the power system, there is significant opportunity to revise Virginia's RPS rules, including to consider utility-borne penalties for noncompliance. This and other potential reforms offer the opportunity to align utility decision-making more directly with objectives for both cost control and reduction in greenhouse gas emissions.

## Existing Ratemaking Structures and Their Performance

Virginia's electric IOUs are subject to a broad and interrelated set of policies, procedures, and ratemaking structures, as previously described. All of these combine to influence electric utility performance and outcomes. This discussion will focus on a limited number of notable features in Virginia regulation and their relationship to utility cost centers, which we identify as having the most profound influence on utility performance against identified performance areas.

### *Revenue Adjustment Clauses (RACs)*

RACs—commonly called riders or trackers in utility ratemaking—constitute a large portion of Virginia electricity customers' bills. RACs are separated from "base rates" so they receive independent regulatory review or serve as a pass-through for costs considered to be outside a utility's control. In Virginia's case, many RACs originate from state legislation, reflecting public policy priorities or other desires for separate rate treatment. The use of riders is increasingly common across the US, including for costs related to generation and distribution infrastructure construction, though Virginia's reliance on RACs relative to total rates is significantly higher than peer jurisdictions.[35]

Figure 13 below shows a breakdown of the RACs contained in APCo and Dominion residential rates, including those previously grouped as "Other RACs" in Figure 6, *Cost components of a typical monthly residential electricity bill in Virginia (1,000 kWh consumption) in 2025*. That is, they exclude transmission and pass-through fuel costs, while including a wide variety of other costs including some that would, under a different regulatory construct, be included in base rates. The RACs represent a range of policy imperatives as well as supplemental grid

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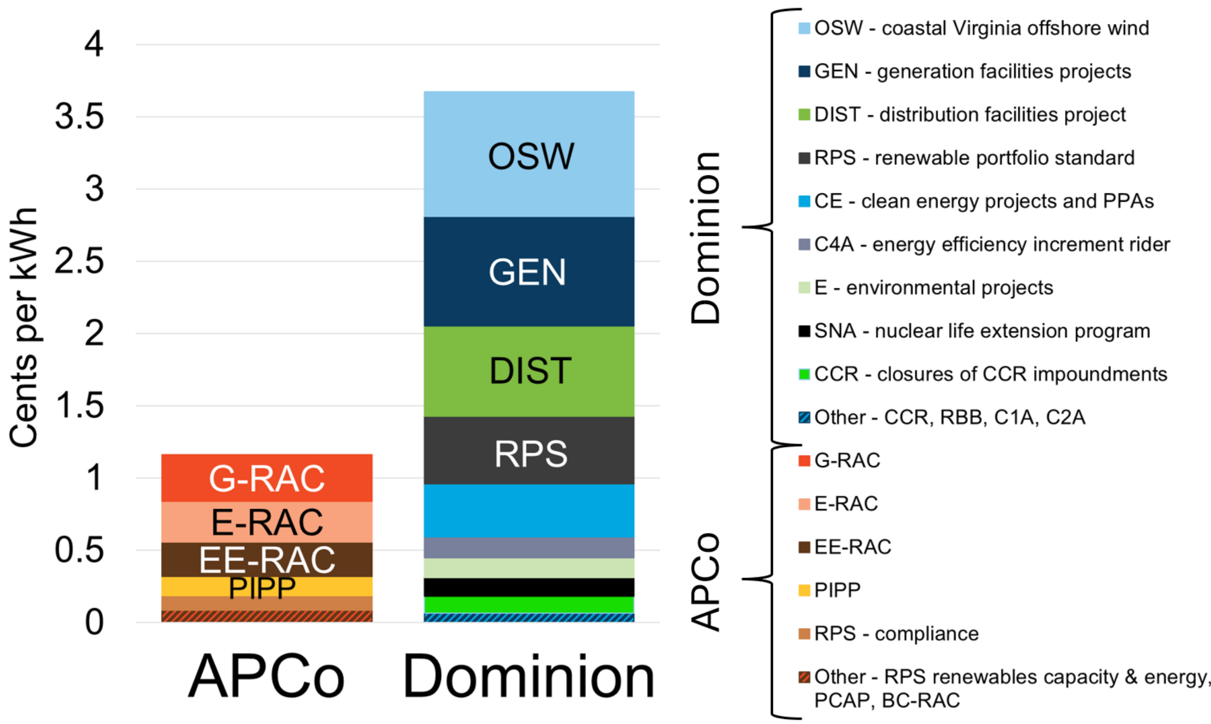
[34] Michael D. Thomas, Report of Michael D. Thomas, Senior Hearing Examiner (August 30, 2024), Case No. PUR-2024-00020, *Petition of Appalachian Power Company for approval of its 2024 RPS Plan under § 56-585.5 of the Code of Virginia and related requests*.

[35] Russell Ernst, Brian Collins, and Monica Klinka, *Adjustment Clauses: A state by state overview* (S&P Global Market Intelligence), p. 4.

investments that have been approved over the years, in addition to some more minor operating expenses such as taxes. In Virginia, the utilities' authorized rate of return is applied directly to numerous RACs, thereby providing an increased measure of certainty for revenue and utility profit within narrow subcomponents of the utility business.

**Figure 13: RACs for Virginia's electric IOUs (excluding fuel and transmission riders)**




Sources: "Residential Rates," Dominion Energy, accessed July 24, 2025; "Business Rates," Dominion Energy, accessed July 24, 2025; Appalachian Power Company (APCo), *Virginia SCC Tariff No. 28*, December 11, 2024; Appalachian Power Company (APCo), *Select Schedule Charges and Associated Rider Charges*, January 1, 2025. Figure by CEG and GPI with assistance from PNNL.

Note: Excludes fuel costs, transmission costs, and sales and use taxes.

Dominion, in particular, demonstrates a very large proportion of customer bills collected though an assemblage of RACs, some relatively small and others more significant. Some reliance on RACs, or riders, is common in modern utility ratemaking; however, in aggregate they represent a shifting of costs from the utility's consolidated capital budget to a set of individual accounts for special purposes. This has the effect of scattering costs into numerous accounts and separate, less connected reviews that make it harder to get a full picture of the utilities' total costs.

The four largest RACs on the Dominion bill are:

- **Offshore wind (Rider OSW)** for collection of costs associated with Dominion's construction of the Coastal Virginia Offshore Wind project. In the September 2024 to August 2025 period, the rider was approved to collect approximately $486 million.[36]
- **Generation facilities (Rider GEN)**, created in spring 2025 to combine six previous riders for various individual power plants (solar, biomass, and natural gas) as well as an LNG storage terminal. The RAC will recover approximately $437 million in its applicable Rate Year 1, and $311 million in Rate Year 2.[37]
- **Renewable portfolio standard (Rider RPS)** to pay for utility compliance with the Commonwealth's RPS standard. In the September 2024 to August 2025 period, the rider collected allowed revenue of approximately $358 million.[38]
- **Distribution system investments (Rider DIST)** to collect revenue for a variety of projects including grid modernization, cybersecurity, distribution undergrounding, and more. This RAC is the combination of two previous RACs, Rider GT and Rider U, and will collect approximately $267 million in its first year (beginning June 1, 2025). [39] Although the total Rider DIST revenue requirement is less than that for Rider RPS, allocations by class appear to result in a slightly higher rate for DIST compared to RPS.

More than a dozen other RACs are included on the Dominion bill, collecting revenue for utility responsibilities ranging across energy efficiency program management, rural broadband buildout, distribution system undergrounding, clean energy projects, environmental costs from coal power plants, and more. In some cases, they represent cost categories that could otherwise be embedded within base rates, such as riders for distribution system buildout and grid modernization. Each RAC represents an identified policy priority or other item for cost recovery. However, in aggregate they display an exceedingly narrow breakdown of costs that is far too complex for the average ratepayer to make any sense of.

Both APCo and Dominion have increasingly relied on RACs over time. As reported by the SCC in 2024 (see Figure 7, *Historical cost components of typical monthly residential electricity bill in Virginia [1,000 kWh consumption, summer month]*), the majority of rate increases in the past 15–20 years have occurred via RACs, while base rates and fuel costs have, in comparison, been more stable. In Dominion's case, the typical monthly residential bill increased almost 50

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[36] Virginia State Corporation Commission, Final Order (July 25, 2024), Case PUR-2023-00195, *For revision of rate adjustment clause: Rider OSW, Coastal Virginia Offshore Wind Commercial Project, for the Rate Year commencing September 1, 2024.*

[37] Virginia State Corporation Commission, Final Order (February 27, 2025), Case PUR-2024-00097, *For approval of a rate adjustment clause, designated Rider GEN, under § 56-585.1 A 6 of the Code of Virginia and the consolidation of Riders B, BW, GV, US-2, US-3, and US-4 pursuant to § 56-585.1 A 7 of the Code of Virginia.*

[38] Virginia State Corporation Commission, Final Order (August 7, 2024), Case PUR-2023-00221, *For revision of a rate adjustment clause, designated Rider RPS, under § 56-585.1 A 5 d of the Code of Virginia for the Rate Year commencing September 1, 2024.*

[39] Virginia State Corporation Commission, Final Order (May 1, 2025), Case PUR-2024-0013, *Petition for approval of a rate adjustment clause, designated Rider DIST, under § 56-585.1 A 6 of the Code of Virginia and the consolidation of Riders GT and U pursuant to § 56-585.1 A 7 of the Code of Virginia.*

percent from 2007 to 2024, from $90.59 to $133.74, during which time RACs expanded from zero to almost $40 for the typical customer.[40]

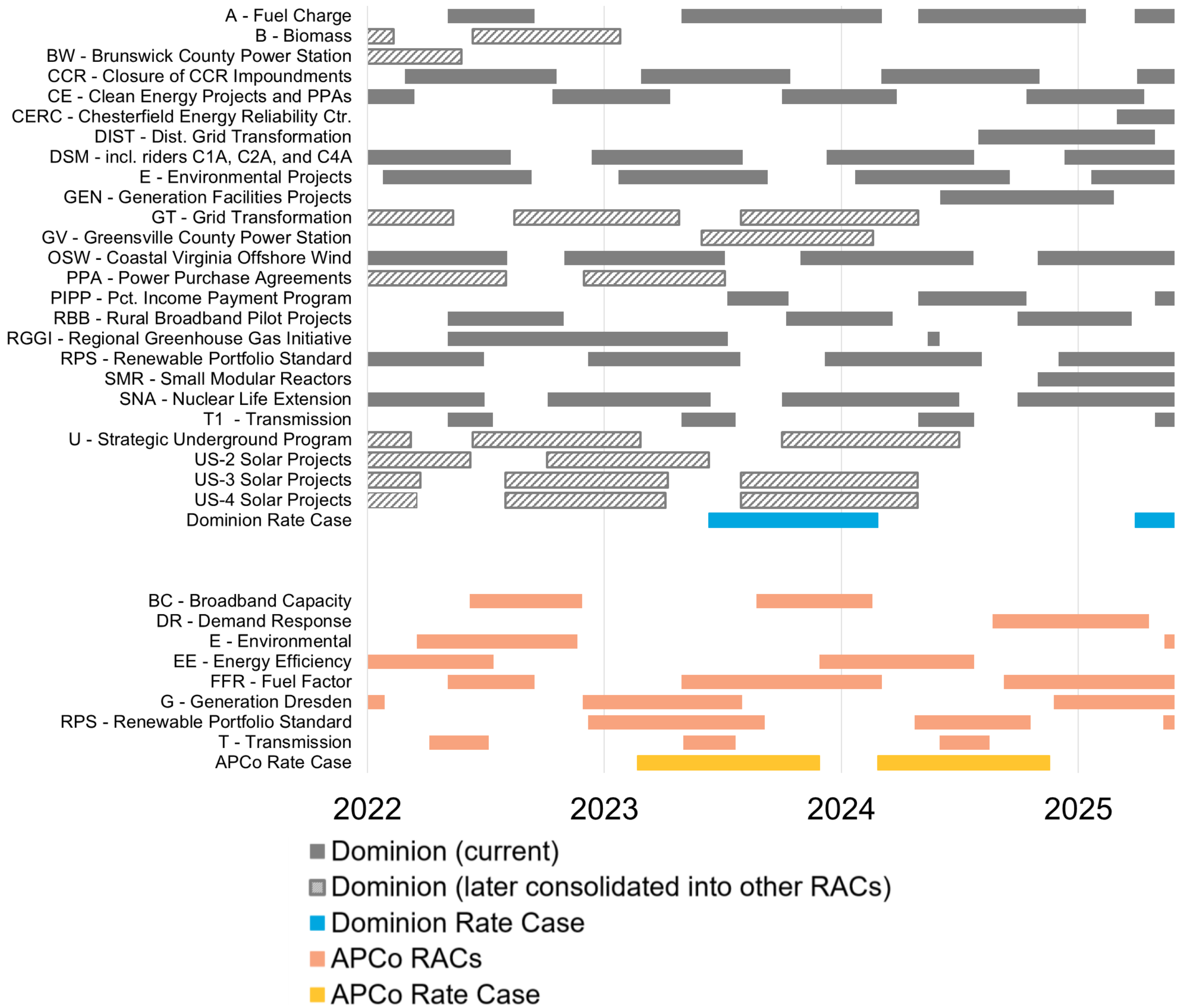
For APCo residential customers, a typical bill increased by 158 percent from $66.61 to $172.09 per month over the same period. In contrast to Dominion, all portions of the APCo bill grew over that time, but RACs still constitute the largest increase: $1.84 per month in 2007 to $47.91 in 2024.[41] The relatively smaller proportional growth here, in which other portions of APCo's bills increased in addition to RACs, may reflect less reliance on RACs by APCo for new areas of investment, as compared to Dominion's favored use of RACs. Nonetheless, RACs are a substantial portion of electricity bills for both utilities.

Although RACs can increase visibility of individual cost components of the bill, in practice they may be counterproductive to regulatory objectives for cost containment and even transparency. In particular, the extensive use of RACs creates undue administrative burden and potential for reduced attention from utility management. Many RACs require individual regulatory reviews, sometimes annually. This creates a significant administrative burden on the SCC, utilities, and intervenors to participate in numerous overlapping proceedings. See Figure 14 below for a timeline of recent RAC proceedings at the SCC. This chart illustrates the substantial regulatory and administrative burden resulting from this reliance on numerous RACs. This is especially true for Dominion, although there is arguably room to reduce the number of RACs for both utilities.

[40] Virginia State Corporation Commission, *Status Report: Implementation of the Virginia Electric Utility Regulation Act* (November 1, 2024).

[41] SCC's 2024 Status Report on the Implementation of the Virginia Electric Utility Regulation Act.

### Figure 14: Virginia RAC proceedings for Dominion and APCo, January 2022–May 2025




Sources: "Residential Rates," Dominion Energy, accessed July 24, 2025; "Business Rates," Dominion Energy, accessed July 24, 2025; Appalachian Power Company (APCo), *Virginia SCC Tariff No. 28*, December 11, 2024; Appalachian Power Company (APCo), *Select Schedule Charges and Associated Rider Charges*, January 1, 2025. Figure by CEG and GPI with assistance from PNNL.

Note: Displayed RACs include those from the Dominion residential tariff effective June 1, 2025, and APCo tariff effective January 1, 2025. Dominion also includes two potential RACs for which proceedings began in late 2024 or in 2025 but do not yet appear on customer bills (Small Modular Reactors [SMR] and Chesterfield Energy Reliability Center [CERC]). Length of cases is measured from initial utility filing to final commission order. Significant attempts were made to accurately reflect the full set and timelines of various RAC proceedings; however, some proceedings or details might be missing. For Dominion, three RAC proceedings are excluded (Rider R [Bear Garden], Rider S [Virginia City], and Rider W [Warren County]) because the end of reviews took place in early 2022 before those were moved into base rates in 2023 at the direction of statutory updates. For APCo, stand-alone filings for Riders SUT and PIPP were not identified within the date range and therefore are not included. The RPS proceeding appears to cover A.5 RPS RAC, A.5 PCAP RAC, and A.6 RPS RAC, but this was difficult to confirm from case reviews.

The 2023 updates to the Regulation Act took steps to reduce the number of RACs on Dominion bills, allowing the SCC to determine, at its own initiation or by petition of the utility, to "direct the consolidation of any one or more subsets of rate adjustment clauses … in the interest of judicial economy, customer transparency, or other factors the Commission determines to be appropriate."[42] Some effort has been made under this authority, including the above-mentioned Rider GT and Rider U consolidation into a single new Rider DIST, and the consolidation of multiple generation facility riders into a new Rider GEN. Dominion's Rider CE (clean energy) and Rider PPA were also consolidated in 2024.[43] These consolidated proceedings are represented in the Dominion chart where shaded gray bars indicate RACs that were subsequently combined or merged into a different RAC. That consolidation should reduce some of the total administrative burden, and more consolidation could be considered going forward.

Administrative costs are not the full story, however. Rather than provide consolidated review of the utility's total investments and allow judgment on the prudency of business decisions, as may be their intention, individual RAC proceedings could have the practical effect of hiding costs in many disparate dockets and accounts. Meanwhile, smaller, less-resourced parties are likely unable to participate in every docket. Because various special projects or cost components are examined in a large and disconnected set of reviews, it can diminish regulators' and intervenors' ability to make a holistic review of how investments and cost management is being handled across the utility enterprise.

Participants in the Department stakeholder process expressed similar concerns with the use of RACs in Virginia. A 2021 report prepared on behalf of the Virginia Poverty Law Center demonstrates that Virginia uses RACs disproportionately more than other states, particularly for revenue collection for generation project investments that would normally be accounted for in base rates and associated proceedings. That report further concludes that Virginia's use of RACs displays a high degree of legislative precision, limiting regulators' authority to consider RACs within prudency reviews, which normally are the purview of regulators.[44]

RACs may also limit the utility's ability or interest to strategically manage between parts of its business because each RAC is effectively treated as its own revenue and cost center with limited discretion (or incentive) to optimize between these. Although RACs succeed in providing revenue stability and greater assurance of cost recovery for utilities, overreliance on them can decrease utilities' incentive for cost containment and limit their ability to strategically manage across business objectives and policy requirements in a coordinated manner. That limitation appears to also be imposed on the SCC's reviews of RACs in balance with other cost drivers, because Virginia Code states that "any petition filed pursuant to subdivision 4, 5, or 6 [RAC authorizations] shall be considered by the Commission on a stand-alone basis without regard to the other costs, revenues, investments, or earnings of the utility."[45] This language may prevent the SCC from assessing RAC costs and the performance of those investments in a coordinated

[42] Virginia Code § 56-585.1.

[43] SCC's 2024 Status Report on the Implementation of the Virginia Electric Utility Regulation Act.

[44] E9 Insight on behalf of Virginia Poverty Law Center, *Thumb on the Scale: An Examination of Utility Rate Adjustments and the Role of the Virginia Legislature* (September 2021).

[45] Virginia Code § 56-585.1.

manner with other utility costs and programs, above and beyond inherent limitations due to RACs' separation into a dispersed set of dockets.

It is not necessary to recover all costs associated with public policy objectives through separate RACs. This is reflected in existing provisions of the Virginia Code such as § 56-585.1:13, which asserts that costs associated with investments in transportation electrification should only be recovered through base rates for generation and distribution.[46] This provides a model for how other public policy imperatives may be migrated into base rates in the future, thereby consolidating ratemaking and billing components while enhancing the Commission's ability to review costs in a more holistic or interconnected manner.

### *Return on Equity (ROE)*

Virginia statute has applied changing rules and parameters to the setting of the electric IOUs' allowed ROE over time. While it was once at the general discretion of the SCC in accordance with common US regulatory practice to permit a fair opportunity to earn a return, legislative revisions over the past 10 years applied more specification and limitations on the SCC's discretion in this area. This includes prior legislation directing APCo's allowed ROE to be set according to benchmarking against peer IOUs in a specified set of southeastern states. This and other provisions in the Virginia Code may have the undesired effect of artificially tethering Virginia utilities' earnings to factors that are divorced from market fundamentals or utility performance.

Changes to the Regulation Act in 2023 made constructive improvements to the practice of determining utility ROEs in Virginia by returning discretion to the SCC to determine a fair return. While it legislated a 9.70 percent allowed ROE for Dominion in its current period, the 2023 updates authorize the SCC to determine ROE going forward at its discretion using any methodology that is consistent with the public interest. The SCC may also increase or decrease a utility's combined rate of return by 50 basis points based on performance factors including reliability, generating plant performance, customer service, and utility operating efficiency. These updates provide the SCC useful authority, by which it can ensure that utilities maintain a fair opportunity to profit while also maintaining ROEs at levels that reflect risk-adjusted market conditions and utility performance.

As previously stated, Virginia also allows earning on some (but not all) RACs, which has the effect of spreading the utility collection of earnings-eligible revenue across many separate accounts. In some cases, these may not permit meaningful review of their relation to operational performance or if costs are prudently incurred, as compared to ROE determinations conducted via rate cases. Rather, it appears that the allowed ROE determined in rate cases is subsequently applied to some RACs, *assuring* profit collection rather than simply providing an *opportunity* to earn profit.

The net effect of this practice is to separate earnings into numerous individual accounts and collections, thereby incentivizing the utility to increase and optimize those cost categories where earning is larger or more assured. This is in contrast to a competitive firm (or a utility with a

[46] Virginia Code § 56-585.1:13.

more consolidated set of revenue collected in base rates), in which investments and management decisions need to optimize *between* cost centers to achieve operational efficiency and to increase value to customers as well as to the business.

### *Earnings Sharing*

There are provisions in Virginia Code for a type of earnings sharing mechanism (ESM) if a utility earns in excess of the fair rate of return on common equity (aka ROE) set in the previous rate case. For Dominion, 85 percent of earnings must be credited back to customers for any excess earnings up to 150 basis points above the allowed ROE. All excess earnings above this 150 basis point threshold are returned to customers over a 6–12 month period after the rate case is settled.[47]

APCo's ESM is described in a different section of Virginia Code and is structured differently. In APCo's case, any earnings within 100 basis points above or below the SCC-determined ROE (as set in the last rate case) are considered reasonable and no adjustment is made. If APCo's realized ROE deviates by more than 100 basis points above the allowed ROE, then customers are credited 100 percent of all earnings above the 100 basis point threshold.[48]

These Dominion and APCo structures can be described as **asymmetric ESMs** because they affect one side (overearning) of the allowed ROE range and not the other (underearning). Dominion's ESM is two-part, in which the sharing ratio changes from 85 to 100 percent at the 150 basis point level and does not include a "no sharing" deadband. APCo's ESM, on the other hand, has a deadband of 100 basis points around the allowed ROE, whereby sharing only occurs above or below this amount.

These structures provide a ceiling that should help limit excessive utility earnings. In this way, ESMs can serve as a useful restraint on excess collections from customers to the benefit of utilities. However, in Virginia, the identified ESMs apply only to utilities' base rates for some generation and distribution costs, which overall constitute a relatively limited portion of the utilities' earnings opportunity. This excludes utility earnings on transmission because those are FERC-regulated, as well as costs subject to RAC revenue collection. Accordingly, the resulting ESM calculations fail to capture those utility earnings that that have been moved into RACs, the effect of which is to make these expenditures function more as a pass-through cost with an automatic margin. This may interfere with the broader purpose of an ESM by limiting utility incentives and the earnings that can be shared with customers.

### *Fuel Cost Recovery*

Fuel costs account for a substantial portion of customer rates, contributing about 18 percent ($23.96) and 24 percent ($41.39) of the typical residential monthly bill for Dominion and APCo customers, respectively, as of 2024 (as seen in Figure 7, *Historical cost components of typical monthly residential electricity bill in Virginia [1,000 kWh consumption, summer month]*).[49] These

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[47] Virginia Code § 56-585.1.

[48] Virginia Code § 56-585.8.

[49] SCC's 2024 Status Report on the Implementation of the Virginia Electric Utility Regulation Act.

amounts have stayed relatively stable for Dominion over the years, ranging between $20 and $30 per month for the typical customer between 2007 and 2024 For APCo, fuel costs varied between about $13 and $30 for the typical customer between 2007 to 2021. More recently, APCo fuel costs substantially increased—by more than 100 percent from July 2021 to July 2024 for the typical customer. This increase in fuel cost accounts for almost 40 percent of the increase in APCo customers' bills in that time period.

For all Virginia electricity customers, fuel costs should be expected to decline as the utilities meet RPS, energy efficiency, and other environmental goals because those should reduce reliance on fossil fuel-derived power. This should have the effect of shrinking fuel costs' contribution to rates, both on a total dollar basis and as a percentage of total costs. Yet there is no indication from recent trends or available information that this is being achieved.

Additionally, a common rationale for collecting fuel costs as an automatic rate adjustment is that fuel costs are "outside the utility's control." This may be a misleading characterization, however, because there are options to enter fuel and purchased power contracting structures to reduce cost volatility or price spikes. Utilities can also manage their generation mix in a manner that limits overreliance on one class of fuels. In light of fuel costs' substantial contribution to total energy costs, it may be appropriate to increase Virginia utilities' incentive to reduce fuel costs, and/or total fossil fuel use, to the extent practical.

All things being equal, the utilities are neither incentivized nor disincentivized to manage fuel costs, whether for cost-containment purposes or to achieve other policy goals. Because these costs are a direct pass-through, however, utilities lack a meaningful motivation to reduce fuel costs. The SCC has some authority to review fuel costs and can disallow costs that it finds were imprudently incurred.[50] The SCC can continue to exercise this authority, keeping key performance areas such as affordability in mind.

Multiple participants in the Department stakeholder process raised concerns about fuel costs and associated incentives (or lack thereof) for utility fuel cost management. Some participants suggested that a fuel cost-sharing mechanism could be complementary to and supportive of goals including energy efficiency, greenhouse gas reductions, and cost containment. Fuel cost-sharing mechanism design is discussed further under "Performance Mechanisms" in Section 3.4, *Detailed Overview of Performance-based and Alternative Regulatory Tools*.

### Overall Assessment of Virginia's Current Ratemaking Construct

As illustrated in this and the preceding section, Virginia's electric utility ratemaking laws and regulations were developed, iteratively built, added to or revised, and restructured at various times over the years due to market restructuring and the pursuit of specific policy objectives. Virginia's electric IOUs are regulated on the foundation of a traditional COSR model, but with

[50] Virginia Code § 56-249.6: "The Commission shall disallow recovery of any fuel costs that it finds without just cause to be the result of failure of the utility to make every reasonable effort to minimize fuel costs or any decision of the utility resulting in unreasonable fuel costs, giving due regard to reliability of service and the need to maintain reliable sources of supply, economical generation mix, generating experience of comparable facilities, and minimization of the total cost of providing service."

significant changes and deviations that make it unique and often difficult to fully comprehend. Some limited “performance-based” regulations are embedded within Virginia’s existing framework, including ESMs, earning on energy efficiency expenses, and more recently consideration of additional PIMs. However, the incentives associated with these are relatively small and overshadowed by other embedded motivations including expanding capital expense, keeping allowed ROEs as high as permissible, and limiting revenue uncertainty wherever possible.

Virginia’s resulting ratemaking structure contains dozens of narrowly constructed cost recovery structures—most notably a heavy reliance on RACs—and involves a complex set of accounting practices and embedded utility incentives. This range of complex structures partitions the utility business into small components to achieve narrow or specific ends, while cost recovery (and sometimes utility earning) for each portion is made more assured through RACs and other structures. Overall, the current structure incentivizes utilities to grow their capital expenditures (rate base), maintain as high an ROE as possible, and reduce or eliminate risks or influence from market factors such as competitive providers, fuel prices, technology evolution, and shifting cost structures.

Some of this is normal and even appropriate for a regulated monopoly that provides an essential service like electricity. It is in the public interest for utilities to have stable, low-risk revenue projections. This supports the financial stability of the utility business, which in turn can support ready access to capital markets for low-cost financing of future investment needs, as well as proper attention to basic service requirements. Reforms should not be made in Virginia that would fundamentally erode or undermine utilities’ financial integrity, particularly utilities’ ability to access low-cost debt financing. Nonetheless, there appears to be space in Virginia’s ratemaking construct to realign incentives in a manner that maintains the utilities’ basic financial and operating parameters while promoting greater cost containment, pursuit of policy goals, and sharing of risks between utility shareholders and ratepayers.

Virginia’s ratemaking structures also rely on an unusually high degree of legislative direction, which in most other states is commonly reserved for state utility commissions. This includes statutorily defined methods for determining utilities’ allowed ROE, narrowly described structures for available ESMs, and heavy reliance on RACs. When these structures are established so discretely via statute, it lessens regulators’ discretion to apply professional expertise and effective monitoring of utility practices.

Legislative updates in 2023 to the Regulation Act appear to make some course correction to incentive misalignments by giving greater discretion to the SCC for ROE determinations; instruction to consider consolidation of some RACs or moving those RACs into base rates; and other expanded opportunities for SCC consideration of prudency, operational efficiency, and potential rewards or penalties for utility performance.

Virginia’s ratemaking construct remains relatively “fixed” in statute, however, as compared with peer states or other jurisdictions that are confronting energy system challenges with increased attention to incentive regulation (including Connecticut, Hawaii, Maryland, and the United Kingdom). The prevailing Virginia regulatory construct may be good for utilities and their investors, who tend to prefer a low-risk, broadly predictable revenue structure. However, it is less well suited to the achievement of new objectives for utilities, including integration of new technologies and customer service innovation, promoting cost containment, and more.

Moving forward, in consideration of mounting cost pressures, load growth expectations, affordability concerns, environmental and other public policy imperatives, and more, the Virginia ratemaking construct may be due for an update. It is beyond this report's scope or ability to prescribe precisely what forms those should take because those determinations should be subject to SCC deliberation, possibly with legislative direction.

As a general matter, however, the most effective regulations can result from the empowerment of regulators in a manner that allows them to exert their expertise and professional judgment, and apply their holistic understanding of the utility enterprise. Effective regulations can include specific ratemaking structures, planning procedures, and financial rewards or penalties that allow utilities to manage their business in a manner that delivers safe, reliable, clean, and affordable electricity service in accordance with the Commonwealth's goals. In this regard, we suggest that the SCC would need additional authority and resources—as well as direction on policy objectives and priority outcomes—to properly design, implement, and maintain a more effective regulatory framework.

The remainder of this report describes a set of regulatory tools, under the general banner of performance-based regulation and alternative ratemaking, that provide options to pursue that end.

## 3.4 Detailed Overview of Performance-based and Alternative Regulatory Tools

This section provides an overview of performance-based and alternative regulatory mechanisms, including a review of common objectives that often inform the development of a PBR framework. The discussion does not provide a comprehensive review of ratemaking theory and practice because there is significant literature and regulatory experience to draw on for that purpose. Rather, this section offers a reference and review for key considerations that could be brought to Virginia if the Commonwealth determines to undertake reform. This review is informed by stakeholder input in the Department's workshop series, as well as practical experience in peer jurisdictions and the context of Virginia's existing regulations.

Interest in PBR reflects a recognition of the shortcomings of the COSR model, as well as an expanded set of outcomes and objectives applicable to the modern utility system. Legislators and regulators may pursue PBR as a tool to help achieve this wide array of policy goals or desired outcomes. Although PBR can seek to address multiple objectives or outcomes, it is useful to prioritize a subset of primary objectives when constructing PBR regulations. Participants in the Department's stakeholder process reflected this sentiment as well, stating a desire to clarify the specific goals and outcomes that a Virginia PBR structure would address.

The policy and regulatory objectives outlined in the Joint Resolution include performance improvement for affordability, reliability, and customer service; enhancing cost-containment incentives; and making progress on energy efficiency and decarbonization goals, all of which correspond to common objectives for PBR. As previously discussed, participants in the Department's stakeholder engagement process expressed interest in improving performance in areas related to clean energy, environmental justice and equity, affordability and cost control, and energy supply and security. Should the SCC undertake future work to design and adopt PBR reforms (that is, beyond the evaluation phase that is the focus of this report), some formalization of priority outcomes is a useful starting point.

Some topics identified in the Joint Resolution are less common for PBR attention, however, or may not be directly addressed by standard PBR tools. Those include concerns for carbon leakage from the manufacturing sector or application of PBR to other entities such as competitive service providers (CSPs). PBR may not be suitable to directly incentivize decisions by these nonutility actors, but there are opportunities to improve regulatory incentive structures to support these objectives such as improvements to planning and resource procurement, and levelizing earning opportunities between capital and operating expenditures to encourage least-cost or highest-value solutions be selected. Though implementing a more comprehensive PBR framework for Virginia's electric IOUs would have minimal implications related to carbon leakage from the manufacturing sector or the operation of CSPs, both topics are discussed in Section 3.6, *Competitive Service Providers and Carbon Leakage from the Manufacturing Sector*, in accordance with the Joint Resolution requirements.

### Common PBR Tools and Their Potential Application for Virginia

The Joint Resolution outlines numerous PBR tools and alternative regulatory mechanisms, which were also discussed throughout the Department's stakeholder engagement process. This section provides a brief review of the most prominent tools, identifies key considerations related to those tools, and discusses how they may interact with other PBR tools or existing ratemaking structures.

If Virginia pursues a PBR regulatory framework, the SCC will need to conduct additional review and should make decisions for how to construct these mechanisms—individually or in tandem—to address Virginia's specific circumstances.

This section divides PBR tools into three different categories, two of which reflect general components of a performance-based structure, and the third including "other" complementary regulatory reforms. The three categories are:

- **Revenue adjustment mechanisms** to establish appropriate revenue levels for cost recovery and associated mechanisms to adjust revenues and/or ensure customer protection.
- **Performance mechanisms** to promote priority outcomes through increased transparency to system outcomes as well as rewards for good performance and penalties for underperformance.
- **Other regulatory structures** to create new processes or institutional arrangements that shift utility functions (or create new functions) in service to identified needs.

While these groupings provide a useful organizing structure by which to design regulations, in reality, performance-based approaches may interact across several categories. This categorization helps identify the most significant or broadly influential incentive features (often embedded in revenue adjustment mechanisms), versus what may be more targeted incentives to specific outcomes or cost categories. This approach is also consistent with industry practice and the approach taken in peer jurisdictions.[51]

### *Revenue Adjustment Mechanisms*

Revenue adjustment mechanisms provide a foundational ratemaking structure that balances utility and customer (ratepayer) interests to fairly collect target revenues, while those same parties share in the risks and rewards from resulting revenue and costs. They can also provide accounting adjustments or modifications to revenue collection.

Mechanisms associated with revenue adjustments include tools that shift regulation away from a backward-looking view of costs and sales to a more future-oriented approach that incentivizes cost control. These reforms are not necessarily a major departure from traditional COSR because they still rely on common features for rate cases and prudency reviews. A fundamental difference, however, is their orientation toward setting ongoing target revenues for a defined period, then holding those levels more fixed than they would be under a COSR framework while the utility takes on greater responsibility to manage its costs.

The following tools are some of the most common revenue adjustment mechanisms employed for PBR.

**Multi-year Rate Plans (MRP)**

When properly designed, an MRP can serve as the foundation for a comprehensive PBR framework. An MRP can be a powerful motivator for utility cost containment enabled by investment efficiency in pursuit of utility earnings.

MRPs require careful design and adherence to proper incentive structures to support regulatory objectives. They also require a highly involved regulator with sufficient technical expertise to establish appropriate MRP structures, mitigate potential for competing or misaligned incentives, and monitor utility performance to maintain or adjust the structure from one rate case to the next.

MRPs typically apply a predetermined total revenue cap (sometimes a price cap) for a three-to-five-year rate case moratorium, commonly referred to as a "stayout period," before the next rate case. Allowed revenue may increase or decrease year to year within the stayout period based on predetermined adjustment factors for exogenous influences like inflation. MRPs can also include the following adjustments, sometimes called attrition relief mechanisms (ARMs):

- Productivity factor ("X-factor") to encourage increasing business efficiency
- Capital adjustment factor ("k-factor") for permissible additions to rate base (*e.g.,* a midperiod grid modernization effort)

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[51] See, for example: Guidehouse, prepared for Edison Electric Institute, "Electricity Regulation for a Customer-Centric Future: Survey of Alternative Regulatory Mechanisms" (2020); Hawaii Public Service Commission, Decision and Order No. 37507 (December 23, 2020), p. 14–17, Docket No. 2018-0088, *In the Matter of Instituting a Proceeding to Investigate Performance-based* Regulation; PURA, Revised Straw Proposal (February 27, 2024), p. 21–23, Docket No. 21-05-15RE02, *PURA investigation into performance mechanisms for a performance-based regulation*.

- Adjustments for unanticipated events ("Z-factor") such as a major storm or recession

Target revenues in each year of the stayout period, including adjustment factors, can be expressed in algebraic form as illustrated below.

**Target Revenue Year N = Target Revenue Year(N – 1) + Inflation – X-factor + k-factor + Z-factor**

Given the index-based adjustments made to a predetermined ingoing target amount, MRPs can provide a clear and transparent revenue outlook, inclusive of fair opportunity for earnings, thereby providing revenue certainty to the utility. In this manner, MRPs should shift utility management attention from revenue collection to efficient cost control during the stayout period.

This section provides only a sampling of some components of an MRP. In practice, MRPs can incorporate many additional features or variations. MRPs are also compatible with other PBR tools such as decoupling, PIMs, or ESMs. Accordingly, MRP design compels a "whole-system" approach with thoughtful development and calibration, often in coordination with resource planning processes, upcoming rate cases, and other regulatory activities.

| **Multi-year rate plan (MRP)** | |
|---|---|
| Purpose | Create cost-containment incentives and greater management discretion to improve utility operations and their investment decisions via predetermined revenue requirements under which the utility has the opportunity to achieve cost savings resulting in higher earnings. Also, reduce the number and frequency of rate cases. |
| Outcomes (performance areas) commonly addressed | • Affordability<br>• Cost-efficient utility<br>• Others based on determinations for priority outcomes in each state or utility |
| Mechanism design | Predetermination of a utility's revenue requirement and base rates through cost forecasts or index-based formulas, set for a prescribed stayout period (rate-base moratorium) of more than one year (frequently three to five years). Revenues and resulting rates adjust during the stayout period based on adjustment factors, cost trackers, or other mechanisms. Requires careful design and monitoring to ensure appropriate incentives in total and interactions with other ratemaking structures. |
| Interactions with other ratemaking tools | Broad interaction with the entire ratemaking construct; however, most directly associated with (or can be designed to include):<br>• Revenue decoupling<br>• Earnings sharing mechanism (ESM)<br>• Performance metrics and scorecards<br>• PIMs (to prevent backsliding on core service requirements, or to promote priority outcomes)<br>• Efficiency carryover mechanism<br>• Rate cases and ROE determinations<br>• Trackers or RACs to consider incentive structure and cost containment on a total system basis |

To be meaningfully performance-based, an MRP should include a total revenue cap with limited automatic adjustments. Those adjustments should be set according to predetermined factors or established criteria. In the absence of these or other MRP best practices (*e.g.*, if a stayout is permitted but is overly reliant on formula rate adjustments and/or external trackers/RACs), cost-containment incentives are severely diminished and this is not properly called an MRP.[52]

For Virginia, MRPs could be a logical evolution of current biennial reviews. An MRP-based performance structure could provide an effective, broad-based incentive for cost containment while creating the foundation for achievement of other outcomes. Where current biennial reviews serve to bundle two years into one rate case, an MRP approach would expand this to three to five years and would review the full stayout period in a consolidated manner (*i.e.*, rather than each year being treated as somewhat independent). Anticipated rate reviews for the 2027 and later period provide an opportunity to consider adoption of MRPs. However, because Virginia statute currently prescribes two-year rate reviews, statutory revision would be required to lengthen stayout periods in alignment with an MRP standard of three or more years.

MRPs also require careful up-front design considerations as well as monitoring during the stayout period to evaluate performance. Virginia would need to dedicate additional attention to determine how ingoing rates get set, what are appropriate adjustment factors for the electric IOUs, and how to calibrate an MRP with other PBR mechanisms.

In summary, well-designed and impactful MRPs require time, resources, and political support to empower the regulator with appropriate discretion and to ensure that desired results are achieved without gaming, backsliding, or too much insulation from competitive market decision-making. In light of all these factors, MRPs may be an appropriate medium-term goal for Virginia utilities, following one additional cycle of two-year rate reviews.

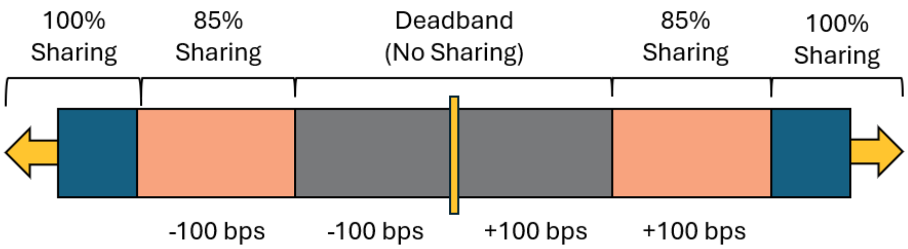
**Earnings Sharing Mechanisms (ESMs)**

ESMs create a structure by which the utility shares over- or underearning outside a targeted ROE with customers. This protects the utility from underearning and protects customers from paying for excess utility earnings. Under an ESM framework, utilities are highly incentivized to contain costs because they receive higher profit if cost-containment strategies succeed, meaning that cost containment is well incentivized. They can also insulate the utility from downside earnings risk and avoid excess earnings. This is a particularly useful feature in MRPs, in which a strong cost-containment objective could result in significant cost cutting and business efficiency improvements, but without those benefits being shared with customers. For these reasons, ESMs are an important feature of a PBR structure.

Figure 15 below illustrates how an ESM can be designed, in this case reflecting symmetrical sharing with a deadband around a target allowed ROE.

[52] These differences are described by Synapse (2019): “Multi-Year Rate Plans: Core Elements and Case Studies.” Prepared for Maryland PC51 and Case 9618. That work highlights important distinctions between revenue cap versus forecast MRPs, as well as MRP differentiation from formula rate plans, which should be carefully considered during the development of an MRP to avoid pitfalls that can dampen intended cost containment objectives.

**Figure 15: Illustrative design of a symmetric ESM with deadband**




Source: Figure adapted from RMI, "Examples & Lessons Learned from PBR in Practice," January 17, 2025, p. 18.

ESMs reduce the potential for a perverse ROE outcome. They should be designed in concert with setting the ROE as well as establishing other regulations because fundamental cost-containment incentives and assurance of fair earnings start with other areas of the ratemaking construct. In combination, such a structure enables fair earning opportunities for the utility and balances utility interests with customers. An ESM can also maintain allowed ROE in a range that helps support utility financial metrics and necessary capital raises from debt and equity markets. The range can include a lower band that supports fair opportunity to earn a return and an upper band above which earnings may not be justified.

Regulators can consider incorporating specific features into ESM design, such as whether to apply a "deadband" around a target ROE within which there is no sharing (*i.e.*, utility retains all earnings, or bears risk of underearning). A deadband can be designed to be symmetrical or asymmetrical. ESMs with asymmetrical deadbands enable excess earnings to be returned to customers but do not protect the utility from underearning. Regulators may also consider whether the ESM should incorporate sharing "tiers" (*e.g.*, higher amounts returned to customers as overearning increases). These details are generally best decided by regulators' judgment, taking into account the full balance of incentives, earning opportunities, and other structures being co-developed in a PBR approach.

| **Earnings sharing mechanism (ESM)** | |
|---|---|
| Purpose | Support an opportunity for the utility to earn a fair return while sharing with customers the cost efficiency and savings that can result from an MRP or other performance incentives. |
| Outcomes (performance areas) commonly addressed | • Affordability<br>• Cost-efficient utility |
| Mechanism design | Regulator determines the components and structure of the ESM including whether to include deadbands, symmetrical or asymmetrical risk sharing, and if there are tiers of sharing. These structures can be established in numeric terms (*e.g.*, as basis point values or percentage). |
| Interactions with other ratemaking tools | **ROE determinations** to establish a target ROE (possibly in a rate case) around which a sharing structure is applied. **MRPs** to set the parameters for reviews between rate cases. **PIMs** to consider if associated earning opportunities are included in the ESM. **Trackers (or RACs)** to similarly consider how associated earning opportunities are incorporated into the ESM. |

In Virginia, ESMs are in place for Dominion and APCo, as discussed in Section 3.3, *Analysis of Electric Utility Performance Under Current Regulatory Construct*. These provide an existing structure and administrative experience to build upon, should the Commonwealth seek to maintain an ESM in a PBR framework. Notably, the existing ESMs in Virginia are defined in statute and only apply to a portion of utility earning opportunities (*i.e.*, base rates; not RACs). Legislative updates could consider whether to broaden the ESM to apply to earnings on RACs as well, thereby capturing a fuller utility earnings and financial picture, as well as subjecting a greater share of utility revenue and costs to embedded performance incentives.

**Revenue Decoupling**

Under traditional COSR frameworks, utilities are incentivized to increase their total electricity or gas sales as a means to increase revenue and pad their margin on relatively fixed costs. This is commonly referred to as a "throughput incentive." Revenue decoupling is a long-standing regulatory tool that can be implemented independently or as a feature of more holistic reforms. Removing the throughput incentive has several potential benefits:

- Mitigating possible utility resistance to or incentive misalignments for energy efficiency and other demand-side resources like rooftop solar
- Providing revenue stability to utilities, thereby reducing financial risk
- Insulating customers from overpaying for fixed system costs

Decoupling does not, in itself, encourage investment or strategic attention to energy efficiency or other clean energy outcomes. Rather, it removes possible disincentives for these programs, while other tools like an energy efficiency resource standard or performance incentives (*e.g.*, PIMs) help promote their achievement. Decoupling design should not happen in isolation, but rather should proceed following decisions regarding whether other PBR structures such as MRPs will also be adopted. Decoupling structures require careful design for alignment with such other structures. Important design considerations include identifying what costs decoupling will pertain to, what methods and forecast assumptions apply to its calculations, and if the decoupling structure's risk-mitigating effects should be accounted for in related ROE decisions.

| **Revenue decoupling** | |
|---|---|
| Purpose | Mitigate utilities' "throughput incentive" to sell higher volumes of electricity. Can also provide revenue stability to the utility, reducing the perceived utility risk profile. |
| Outcomes (performance areas) commonly addressed | • Affordability<br>• Energy efficiency<br>• Peak demand reduction |
| Mechanism design | Requires predetermination of allowed revenue, which is then compared to actual revenue collected from rates to make an ex post true-up (collected from or returned to customers in subsequent bills, often as a monthly reconciliation). |
| Interactions with other ratemaking tools | **PIMs**, **energy efficiency standards**, or other performance mechanisms can be designed to create targeted incentives for desired performance areas. Frequently included as a complementary component of **MRPs**. |

Virginia does not currently employ decoupling for its electric utilities. Decoupling is a worthwhile PBR reform to consider because it can support multiple objectives including cost containment and promotion of energy efficiency and clean energy programs. In Virginia, decoupling could help support achievement of energy efficiency and DER deployment goals—outcomes of significant interest among participants in the Department-led stakeholder process.

Decoupling also seeks to improve revenue stability. However, this is largely accomplished in Virginia's existing regulations by the Commonwealth's extensive use of RACs. For this reason it might not be appropriate—and could in fact be counterproductive or unnecessarily complex—to add revenue decoupling as long as the framework continues to extensively rely on RACs. Accordingly, Virginia policymakers should evaluate the applicability of decoupling and how to achieve its desired results, but only in concert with full consideration of, and possible reforms to, other ratemaking elements.

**Equalization of Capital and Operating Expense**

Capex-opex equalization is not a single PBR mechanism but rather reflects a frequent objective in PBR and alternative ratemaking, which can be pursued through a suite of incentive mechanisms. This objective derives from the recognition that under traditional COSR frameworks, utilities have inherent "capital bias" because profit derives from rate-based capital expenditures (capex) while operating expense (opex) is passed through to customers. As a result of this structural model, utilities may overlook high-value, lower-cost opex solutions such as energy efficiency, demand-side management, and even other novel and highly innovative technologies such as virtual power plants[53] in favor of larger capex infrastructure projects that they can spread across their rate base, such as generation projects or transmission and distribution buildout. This concern has become increasingly relevant in an era of growing potential for operational innovations such as software-based digital services, customer-sited assets or programs, and opportunities for third-party development of contracted solutions.

Available tools for capex-opex equalization include the following, each of which have varied breadth in their application (*i.e.*, targeted versus system interventions), and which require design consideration specific to the applicable jurisdiction and ratemaking structure:[54]

- **Opex capitalization** to allow rate basing for inclusion in allowed earnings of select areas of operating expense determined to be of high value or to offset capex, such as software or DER program management.

[53] In 2025, the Virginia General Assembly passed legislation directing Dominion to develop a virtual power plant pilot program for SCC review (see Virginia Acts of Assembly, Chapter 712). While pilot program details are still being refined, at a high level, such a program would enable residential, commercial, and industrial customers to enroll in the virtual power plant. The virtual power plant would encompass a wide range of distributed energy resources, which—in aggregation—should provide similar (or potentially additive) services to a more traditional utility-built, -owned, and -operated large generation facility. Virtual power plants are one of numerous opex solutions a utility could consider in lieu of a large capital expenditure, under appropriate circumstances.

[54] RMI, *How to Restructure Utility Incentives, for additional information on these capex–opex equalization tools* (July 2024).

- **Targeted PIMs** to allow earning on applicable costs if prescribed targets are met on programs that are otherwise paid from opex and that can offset capex.[55]
- **Modified clawback mechanisms** to permit the utility to retain a share of the cost savings that would otherwise be "clawed back" (hence the modification) in cases in which operating expense is substituted for capital expense.[56]
- **Calibrated efficiency carryover mechanism (ECM)** seeks to equalize the cost-containment incentive for both capex and opex. Calibrated ECM is a variation on an ECM, which allows the utility to retain a portion of cost savings achieved during an MRP.
- **Totex accounting** replaces standard capex and opex accounting categories with a single "total expenditures" (totex) account. That amount is divided into "fast money" and "slow money," the latter of which earns a return similar to rate-based capex. However, the utility's incentive to spend on one type of project over another is diminished if not eliminated.

Of the above tools, opex capitalization and targeted PIMs are more common in practice and relatively straightforward to incorporate with existing structures. They offer approaches to promote desirable programs or test new solutions such as non-wires alternatives. They might not, however, overcome deeply engrained capital bias that results from the COSR paradigm because they can provide additional earning opportunities that do not diminish the utility's inherent desire to grow its rate base. Accordingly, they should be designed with a systemic review to broader incentive structures including total ROE and the balance of other PIMs or relative earning opportunities.

A modified clawback mechanism and calibrated ECM, on the other hand, are mechanisms that can be incorporated into the foundational ratemaking construct, including MRPs. These tools encourage the utility to seek capital expense savings within a rate case stayout period and to pursue operating expense alternatives, including non-wires alternatives. Similar to a shared savings mechanism, these tools allow the utility to retain a portion of savings, thereby encouraging them to pursue the savings in the first place. For both tools, it is critical that regulators pay careful attention during the design phase, with consideration for potential interactive effects with other ratemaking features (including allowed revenue and cost forecasting). Subsequent accounting review is also required to ensure objectives are satisfied. These tools are employed in a few jurisdictions, including New York for the modified clawback mechanism and Australia for the calibrated ECM, while variations or similar concepts by a different name appear elsewhere.

Totex accounting provides the most complete reform to encourage capex-opex equalization because it tackles the underlying paradigm of focusing utility earnings opportunity on capital investments. It would truly put capital and operating expenses on a level playing field because

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[55] Targeted PIMs of this form are more accurately considered among the "Performance Mechanisms" set of tools, below. However, this is included here in recognition of their application to equalize incentives for capital and operating expense (even though it may change incentives but not achieve "equalization").

[56] Clawback mechanisms are also referred to as a net plant reconciliation mechanism in some states, which can similarly be modified to support a capex-opex equalization objective.

the focus is no longer the *type* of expenditure but rather allowing utilities a fair return on their total expense. In this manner, it empowers the utility to make more strategic business decisions, akin to a competitive firm. Totex is a fundamental component of the United Kingdom's PBR structure and is being adopted in Italy. Totex has not yet been meaningfully explored in the US and questions remain regarding its permissibility under the US' Generally Acceptable Accounting Principles, though some research indicates that it would be compatible.[57]

| **Capex-opex equalization** | |
|---|---|
| Purpose | Address the capital expenditure bias inherent in traditional COSR, thereby providing utilities with more equal interest and earning opportunities to pursue all available solutions. |
| Outcomes (performance areas) commonly addressed | • Cost containment (affordability)<br>• Energy efficiency<br>• Third-party solution development<br>• Peak demand reduction<br>• DER integration |
| Mechanism design | Design is highly dependent on which mechanism is applied. Key considerations include identification of which outcomes and associated metrics are targeted, or accounting standards and oversight for tools that may be incorporated into an MR structure. Totex accounting would introduce a different set of design decisions, including setting of an appropriate capitalization ratio for what percentage of expenses can earn a return. |
| Interactions with other ratemaking tools | The relationship of capex-opex equalization strategies is highly dependent on the choice of which mechanism is applied and what outcomes or performance areas are targeted. Under any circumstances, they will have important interactions and dependencies with rate cases including determinations and adjustments to **ROE**. Targeted strategies may be considered in relationship to other **PIMs and associated metrics**, while other mechanisms in the option set could be designed as part of an **MRP with revenue cap**. Capex-opex equalization also has importar interaction with and influence from **resource planning and procurement** processes because those may create the baseline and comparisons from which earnings are calculated. |

The Virginia Code currently permits APCo and Dominion the opportunity to earn on operating expenses associated with energy efficiency program costs, if energy efficiency targets are achieved. This reflects a narrowly targeted "opex capitalization" mechanism and is discussed in Section 3.3, *Analysis of Electric Utility Performance Under Current Regulatory Construct*. Meaningful opex-capex equalization in Virginia would require more complete reform, with due consideration to what outcomes or operating expenses the tool seeks to promote, and must be balanced with other incentive realignment.

Although full equalization of capex and opex (*i.e.*, totex) holds intuitive appeal and could be a powerful force to remake utility strategy toward modern needs and available solutions, this change should only be undertaken if Virginia determines to pursue other comprehensive reforms. In the absence of that, Virginia may consider other mechanisms identified in this

[57] Cara Goldenberg, David Posner, Kaja Rebane, Uday Varadarajan, *Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States* (RMI, July 2022).

discussion, whether related to alternative solution development (*e.g.*, non-wires alternatives) or in concert with MRP rate cases to introduce something like a calibrated efficiency carryover mechanism.

#### *Performance Mechanisms*

Performance mechanisms provide targeted incentives for a utility to deliver desired outcomes that align with policy and customer priorities. These can be reputational or financial incentives and are typically implemented through a combination of metrics definition, target performance levels, and indexed or peer benchmarking. Financial incentives provide upside or downside earning opportunities to the utility, realized as *ex post* additions or subtractions to allowed revenues and earnings as established in rate cases or in individual adjustment clauses and their related proceedings. Reputational incentives offer a means through which utilities can demonstrate their performance against a range of identified areas of interest, thereby indicating the extent to which they align with policy goals and if additional intervention may be warranted. Performance mechanisms are sometimes considered “the frosting” on top of “the cake” that is base rates and revenue adjustment mechanisms—meaning they can provide sweeteners (or penalties and risk sharing). However, the bulk of ratemaking incentives are embedded in other ratemaking practices.

**Reporting Metrics and Scorecards**

Reporting metrics and scorecards provide tools for greater utility and system performance transparency and accountability. Metrics provide data or measurable results that give insight into utility operations and system outcomes, whereas scorecards are a collection or subset of reported metrics to which performance targets are assigned. These tools are discussed jointly because of this iterative nature.

In many cases, utilities already measure and report on key outcomes of interest or could do so with readily available data. In a PBR construct, metrics aim to improve the manner in which information is reported, such as through consolidated filings or a designated web page, or establish new reporting requirements to gather information and support regulatory objectives. Metrics may be for informational purposes only, without an explicit target or judgment attached. Scorecards provide an additional “scoring” mechanism to help motivate performance on some outcomes. This can create a heightened reputational incentive to invest in and seek higher performance.

Metrics and scorecards can be developed jointly and may be designed with a range of measurement standards, reporting formats, and other features. They are useful in their own right and may be considered a minimum requirement for building other incentive structures, including PIMs. However, because they provide lighter motivation for achievement of key outcomes compared to mechanisms with financial impact attached, regulators should not rely on metrics and scorecards alone in a PBR construct. Furthermore, regulators should be cautious to ensure that metrics and scorecards do not unintentionally create a cumbersome intermediary step if more complete PBR is desired.

| **Reporting metrics** | |
|---|---|
| Purpose | Track outcomes in performance areas identified for attention to provide transparency and better understanding of system performance. |
| Outcomes (performance areas) commonly addressed | Various. Metrics can be created for most areas of utility or system performance. |
| Mechanism design | Requires definition of the metric (*e.g.*, a unit of measure), applicable data sources and method of calculation, and format or requirements for reporting (*e.g.*, compliance filings or public website, etc.). |
| Interactions with other ratemaking tools | **Scorecards** and **PIMs** (metrics serve as a necessary building block for design of these mechanisms).<br><br>Reporting metrics also provide necessary information for monitoring and calculations of other areas of PBR and ratemaking, such as ESM calculations, decoupling adjustments, evaluation of MRP components, and capex-opex equalization tools. |

| **Scorecards** | |
|---|---|
| Purpose | Create targets for system performance, which are tracked publicly and create a reputational incentive for performance improvement. Can also serve as a building block and learning tool for potential PIMs of the future. |
| Outcomes (performance areas) commonly addressed | Various. Commonly employed for traditional performance areas, or newer areas that the regulator seeks improvement in but determines that financial rewards (or penalties) may not be appropriate (for example, if data and measurement are not well established, or PIMs are prioritized for other areas).<br><br>Traditional scorecard metrics include:<br>• Reliability (SAIDI, SAIFI, etc.)<br>• Affordability (average bill, etc.)<br>• Customer service (call center times, customer satisfaction, etc.)<br>• Environmental performance (generation mix, RPS attainment, etc.)<br><br>Newer (emerging) performance areas for scorecards include:<br>• Interconnection speed<br>• DER program participation<br>• Environmental justice and equity |
| Mechanism design | Define a performance target, benchmark, or other scoring criterion for a selection of reporting metrics. Publish performance, including current and historical results. Scoring can be represented graphically or in other numeric manner. Can be designed as a website dashboard or other publicly available format. |
| Interactions with other ratemaking tools | **Performance metrics** provide the baseline data and measurements for a scorecard. Scorecards can likewise present results that are used for calculations or other elements of a PBR structure (*e.g.*, **PIMs**, **ESM** results, or others). |

Based on participant input from the Department's stakeholder engagement process, reporting metrics paired with a scorecard could be useful tools to implement for performance areas in which utilities are underperforming or for which it is challenging to enact other incentive mechanisms. This could include metrics for resiliency, environmental justice and equity, system efficiency, competitive service providers, carbon leakage, and more. In practice, metric and scorecard development does not need to occur in isolation because the process of designing other PBR mechanisms can help identify a useful set of metrics. Regulators should also be cautious to not get "bogged down" in lengthy metric or scorecard design processes at the expense of exploring, developing, and implementing more meaningful PBR reforms that align utility financial incentives with priority outcomes.

**Performance-incentive Mechanisms (PIMs)**

Performance-incentive mechanisms (PIMs) are a popular PBR tool that apply targeted financial incentives to one or a set of desired outcomes. PIMs have been used for a wide range of outcomes including customer service, reliability, DER program participation, greenhouse gas reductions, energy efficiency, capital project construction efficiency, and many more. PIMs can be applied to both core utility service obligations such as reliability, and to more "emergent" objectives for the utility system like DER interconnection. Almost 300 emergent PIMs are recorded in a public database of US experience, over 150 of which are active.[58]

PIMs can help promote new performance areas for which the utility has limited experience and that may fall outside more "traditional" utility responsibilities, but that are identified as key to policy goals or future service. PIMs can also create incentives to avoid degradation in service for core utility functions, which can be especially important in the context of an MRP or other structures with a strong cost-containment incentive. In this context, a "penalty" PIM is useful to prevent backsliding on core responsibilities such as reliability, safety, or customer service, which could otherwise be sacrificed in pursuit of cost reductions.

There is a subspecialty of expertise applicable to designing PIMs, including the design of appropriate metrics and the size and calculation of the financial incentive.[59] PIMs can be designed as fixed monetary rewards, basis point additions to ROE, or as a shared savings mechanism (SSM, described in greater detail below), or can be designed to allow opex capitalization. Regulators should consider whether utilities should have direct control over PIM achievement (*e.g.*, based on spending or activities undertaken), or if the utility should have the ability to influence a result that may be subject to some outcome uncertainty (not unlike competitive market outcomes and profit-making). PIMs should also be set with close attention to their relationship with ROE, including the cost of equity and other available earning opportunities.[60]

These and other considerations must be made in the course of PIM design, which is typically undertaken through devoted dockets or as a component of broader PBR development. Many choices reflect either theoretical positions on appropriate risk-reward for utilities, which will vary

[58] *PIMs Database: Emergent Performance Mechanisms across the United States*, RMI, accessed July 14, 2025.

[59] Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (March 2015);

RMI, *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals*, (2020).

[60] Regulatory Assistance Project, Improving Utility Performance Incentives in the United States, (October 2023).

by stakeholder, or can vary based on the outcome sought and the context of other ratemaking structures.

| **Performance incentive mechanisms (PIMs)** | |
|---|---|
| Purpose | Reward or penalize utility performance with earnings opportunities (or deductions) based on base rates to create heightened attention to key performance areas deemed important for improvement. |
| Outcomes (performance areas) commonly addressed | Various, with wide latitude for outcomes addressed. Applicable performance areas identified in Virginia may include:<br>• Reliability (SAIDI, SAIFI)<br>• Peak demand reduction<br>• Clean energy achievement (*e.g.*, energy efficiency, DER expansion, flexibility, electrification)<br>• Customer service<br>• Emergency response and safety |
| Mechanism design | PIMs should be targeted to an identified outcome (or performance area) for which an associated metric and targets are established. The PIM is then structured according to several options including how large to make the incentive, whether it is symmetrical (reward and/or penalty), and whether the degree of utility control over performance may be appropriate for the PIM (*i.e.*, activity- versus outcome-based PIMs). A regulator-led proceeding is useful to consider these and other factors, receive intervenor input, and establish the PIM. |
| Interactions with other ratemaking tools | **ROE determinations** to balance available rewards and penalties with established "baseline" ROE opportunity. **MRPs** include opportunity to use PIMs to reward performance in priority areas or assign penalties to prevent backsliding in core service offerings such as reliability or customer service. **Shared savings mechanisms** or **capex-opex equalization** if the PIM seeks to incorporate those design options or objective. |

There are many ways in which Virginia may develop PIMs to encourage performance in key areas. As just two examples, energy efficiency and peak demand reduction are identified performance areas in the Joint Resolution, for which there is opportunity to establish one or more PIMs.[61] Currently, the SCC has a separate investigation open to establish metrics and procedures for the use of PIMs via Case No. PUR-2023-00210, described in greater detail in Section 3.2, *Current Legislative and Regulatory Context*.[62] Accordingly, this report does not go into greater detail because issues are being evaluated in that docket.

Reliability metrics are also well suited for performance incentives because many activities and outputs related to those metrics are quantifiable, measurable, and supported by regional and historical utility data. As such, the SCC can consider setting reliability performance targets and determine appropriate incentives. For reliability, downside "penalty" incentives are often applied

[61] American Council for an Energy Efficient Economy (ACEEE), *Performance Incentive Mechanisms for Strategic Demand Reduction* (February 2020).

[62] Virginia State Corporation Commission, Order Establishing Proceeding (December 12, 2023), Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia*.

if utilities' SAIDI or SAIFI performance underperform against a target, particularly if the target is set as a minimum service standard. For reliability metrics that measure customer-level performance, such as CAIDI, upside "reward" PIMs may be appropriate to push utilities beyond their core service obligations.

If Virginia determines to pursue broader PBR reforms, such as adopting MRPs or capex-opex equalization strategies, then fuller consideration of proper PIM design is warranted in that context. That should include consideration of the appropriate number and size of PIMs, in balance with other incentive mechanisms, to provide meaningful "teeth" for their achievement. PIMs should be sized to ensure that rewards or penalties are commensurate with customer or societal value derived. Best practice suggests that a limited set of PIMs (*e.g.*, fewer than five total) may be appropriate for priority outcomes, and those PIMs should be large enough to attract utility management attention, while other earning opportunities should be embedded within core ratemaking structures like a revenue cap MRP.

Alternatively, Virginia may reasonably determine to adopt a set of PIMs independent of broader PBR reforms to complement or expand on the current energy efficiency PIM. The PIMs docket provides a useful starting point for PIM development, including procedural requirements for their design and application. In that case, Virginia regulators appear to have wide latitude to adopt PIMs for priority outcomes.[63] If Virginia does employ expanded use of PIMs, we suggest that the PIMs should be limited in number (*e.g.*, fewer than five) and upside incentives (rewards) should reflect achievable but reasonably challenging targets for priority outcomes for which there is identified need for improvement.

**Shared Savings Mechanisms (SSMs)**

Shared savings mechanisms are a form of PIM that incent the utility to achieve cost savings because it can retain a portion of those savings as profit. This serves to move a portion of what may otherwise be operating expense into an earning opportunity. Although this might appear to give to utilities savings that would otherwise flow to customers, the concept of an SSM is that those savings may not be realized in the first place if the utility is not motivated to seek them. By allowing a shared savings approach, there is incentive to achieve lower costs for ratepayers as well as earnings for the utility, neither of which would otherwise exist.

An SSM is possible for any cost category where there is an opportunity to reduce spending below a baseline value. This includes capital projects with approved costs or other market expenses like capacity cost savings realized from demand response.[64] Setting the baseline is important for any SSM and requires good information and regulatory judgment to mitigate the potential for inflated cost assumptions on the front end, which would make achievement of "savings" easier.

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[63] See Virginia Acts of Assembly (2023 Session), Chapter 749 and the SCC's Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia.*

[64] Fuel costs can also be the subject of an SSM. However, because fuel cost-sharing mechanisms have some additional features, we discuss those separately in the next subsection.

| Shared savings mechanism (SSM) | |
|---|---|
| Purpose | Encourage cost savings for a targeted cost center (*e.g.*, a capital project or DSM program). Ensure that customers receive a share of benefits, while also aligning utility financial interests with pursuit of savings. |
| Outcomes (performance areas) commonly addressed | • Cost containment (affordability)<br>• Energy efficiency and decarbonization (if SSMs are applied to fuel cost savings or other consumption and emissions-related outcomes)<br>• Peak demand reductions<br>• Fuel cost savings (see next subsection) |
| Mechanism design | Requires similar design consideration as PIMs, with added attention to appropriate benchmarking. Baselines can be set at a fixed level (a priori) or as a indexed value such as from peer benchmarking or market data. |
| Interactions with other ratemaking tools | **Metrics** and **scorecards** for determinations related to applicable reporting and benchmarks. **ROE determinations** to align earning opportunities with fair return. **Trackers (or RACs)** where the SSM is associated with targeted spending categories, as appropriate. |

Shared savings mechanisms can be considered for use in Virginia, particularly where potential cost savings are believed to be available but not achieved or known in advance. They can be particularly helpful to accompany programs or alternative solution development that seek to reduce known and measurable (or forecasted) costs elsewhere such as from peak demand costs or capital projects. SSMs can also be used for broader cost categories, such as capital budgets within an annual rate period or MRP (in which case they begin to take on a form similar to a modified clawback mechanism or ECM). In light of these design permutations, Virginia should consider SSMs an available tool but only design mechanism specifics after a cost savings objective and opportunity are identified. The SCC and intervenors can play important roles to propose and refine SSM structures for use.

### Fuel Cost Sharing

The Joint Resolution identifies fuel cost sharing as a ratemaking tool for the SCC to consider in this report. It also received interest from many stakeholders in the Department-led process this year. In contrast to a straight cost pass-through to customers, states have applied different forms of fuel cost sharing to electric utilities. These tools seek to give utilities increased incentive to control fuel contract costs as well as increase their self-interest in fuel-reduction strategies such as energy efficiency, while preserving appropriate protection from market forces.

A fuel cost-sharing mechanism is similar in some respects to an SSM, insofar as the utility has the opportunity to retain savings if actual costs are lower than expected. In addition, the fuel cost-sharing mechanism requires the utility to absorb cost *overruns* on fuel cost expense if those occur.

Fuel cost-sharing mechanisms have been used in at least 37 instances nationwide, most of which remain active.[65] These include both gas and electric utilities and are most often symmetrical in their design to allow upside and downside risk sharing between the utility and

[65] *PIMs Database: Emergent Performance Mechanisms across the United States*, RMI, accessed July 14, 2025.

customers. Hawaii, Missouri, Oregon, Wyoming, and many other states currently utilize fuel cost-sharing mechanisms. Use of a fuel cost-sharing mechanism can promote multiple objectives including affordability, cost-efficient utility operations, decarbonization, and energy efficiency. In this manner, it is an attractive outcome-oriented tool that can achieve broad benefits.

Although design considerations for an effective fuel cost-sharing mechanism requires substantially more attention than this report can provide, some primary considerations are identified below, though this list is not comprehensive and there are several additional factors and information requirements.[66] In addition to the considerations outlined in the text box, fuel cost sharing would require ongoing monitoring and new audit requirements in the associated RAC proceeding or other designated venue.[67]

Although the design requirements and administration of the mechanisms may be involved, a fuel cost-sharing mechanism offers one of the most targeted and potentially impactful interventions that Virginia could adopt. It would also be compatible with existing ratemaking structures (*i.e.*, can be undertaken independently or in concert with other reforms), although it may require legislative authorization or directive to modify the fuel adjustment RAC for this purpose. If the General Assembly determines to implement a fuel cost-sharing mechanism, particularly as a partial reform independent of more holistic incentive realignment, a devoted SCC-led evaluation could be required for a review of options and its development.

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[66] Discussion of fuel cost sharing is informed, in part, by Rebane, et al. (RMI 2023) "Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators." That work and others also offer other tools for fuel cost management, including fuel risk reduction tariffs, efficiency ratios, percentage adders, and additional attention in utility planning and procurement processes. Those tools may also be worth some consideration in Virginia in the context of a devoted review of fuel cost management but are not included here in the interests of brevity and focus on fuel cost sharing as a compelling reform opportunity.

[67] Albert Lin, Jeremy Kalin, and Kaja Rebane, *Learning to Share: A Primer on Fuel-Cost Pass-Through Reform* (April 4, 2023).

### Design Features for Fuel Cost Sharing

Experience with fuel cost sharing demonstrates some of the key design decisions that regulators must consider. These are similar in many cases to design options for SSMs but must be considered in the context of market factors related to fuel costs and the circumstances of the utility in question (including its relative exposure to fuel costs versus other generation sources). Design considerations for fuel cost sharing include the following:

- **Baseline setting:** A sharing mechanism typically needs a reference baseline, above or below which savings (or overages) are calculated. This may be considered the "expected" cost of fuel, to which the actual costs get compared. States commonly use a forecasted value, although a historical average cost is an alternative. These choices introduce many other considerations, including who should conduct the forecast (*e.g.*, the utility or an independent third party), if peer benchmarking is utilized, and more.
- **Sharing ratio:** Compared with standard fuel adjustment clauses where 100 percent of fuel cost is borne by customers, a sharing mechanism would assign a ratio for what percentage of savings are borne by the utility. States have applied ratios ranging from as high as 30 percent to smaller ratios of 5 percent or less. In general, higher ratios (*e.g.*, 10–20 percent) will induce more motivation for utility savings because the utility stands to incur more cost from exceeding forecasted fuel costs. Regulators can also consider increasing the sharing ratio over time as experience is gained and the utility has time to improve its fuel management practices.
- **Symmetrical or asymmetrical sharing:** In the case of fuel cost sharing, there is logic to rewarding utilities for costs lower than expected, while also providing some cost sharing if costs come out higher. A symmetrical incentive does this, and applies the same ratios whether costs are over or under expected, while an asymmetrical incentive could remove sharing entirely or may apply different ratios (for example, less direct pass-through to customers in the case that costs exceed the baseline).
- **Determination of which plants to include:** Fuel cost sharing can apply to one fuel type (*e.g.*, natural gas) or multiple (*e.g.*, coal or other fuel types). Similarly, it can apply to all utility-owned power plants, or limited to new generation.
- **Inclusion of purchased power:** While not within its own fuel cost management abilities, utilities can shift their share of supply between self-owned and purchased power. It may be appropriate to incorporate purchased power in a fuel cost-sharing mechanism or have a comparable structure in place to share the costs of purchased power.

These design variables, and many more, demonstrate the interrelated set of details and determinations that require careful review, analysis, and co-development in the context of each utility. They also indicate the high importance of robust information collection and need for transparency of utility fuel contracts, which should be brought to bear in the initial design as well as subsequent monitoring and calibration of a fuel cost-sharing mechanism. Accordingly, design and implementation of a fuel cost-sharing mechanism requires devoted analysis and stakeholder deliberation, likely in the context of a regulator-led proceeding. State legislatures can play a useful role in authorizing or directing the regulator to undertake this rulemaking.

### *Other Regulatory Structures*

Other reforms can be considered to improve utility regulations, in addition to revenue adjustments and performance mechanisms. Where those previously discussed categories include common PBR tools, this broader set of reforms reflect the connected nature of regulations, planning practices, program design, and utility system dynamics, all of which can support policy or regulatory objectives. Here, a limited set of high-potential options are briefly presented for their possible fit in Virginia.

**All-source Competitive Procurement**

The Joint Resolution requests attention to best practices for all-source competitive procurement. Broadly defined, all-source competitive procurement is a set of approaches to enable the acquisition of new supply resources within a unified process. In this process, the requirements for capacity or generation resources are technology- and ownership-agnostic with respect to the full range of resources or combinations of resources available in the market. In the US, most vertically integrated utilities are either required by regulators to conduct competitive procurement through requests for proposals (RFPs) as part of the process to select adequate generation resources or do so voluntarily. In an RFP, the utility describes the resources it wishes to procure and may also offer self-build options to compete against market offers.

In Virginia, as in many states, this procurement process is informed by resource planning processes, then can be subject to a certificate of public convenience and necessity (CPCN) review, although these often are not co-optimized. For example, a recent RFP and subsequent CPCN proceeding by Dominion prescribed generation requirements that ensured only centralized "peaking and baseload" power plants could qualify and expressly stated that "solar, wind, and energy storage resources will not be considered in this RFP."[68] Outside this and similar RFP processes, there are other procurements and programs by Virginia utilities for the purpose of securing renewable energy and demand-side resource solutions; however, these are expressly separate activities and there appears to be little or no ability to consider how these solutions can serve identified resource needs outside their limited policy-mandated purposes. This makes resource procurement as well as other energy programs for clean energy, such as virtual power plants, effectively siloed and not optimized to secure resources for energy supply needs.

In addition to the opportunity for resource optimization, interest in alternative procurement strategies reflects recognition that utilities have significant market power in securing energy in their territory. As by far the largest buyers of electricity, utilities have monopsony characteristics, meaning they have control over inputs and methods for conducting resource planning, as well as methods and assumptions used to evaluate bids received in competitive procurement processes. Consequently, vertically integrated utilities may be financially incentivized to prefer opportunities to invest their own capital in generation, even at above-market prices, and potentially to the point of costly over-procurement.

In light of recent projections for large load growth, many utilities are eager to acquire new capacity to meet forecasted demand. To ensure that new resource procurements are as cost-effective as reasonably possible to support customer affordability, leading jurisdictions have

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[68] Dominion Energy, Application, DEQ Supplement, Direct Testimony and Schedules of Virginia Electric and Power Company; For approval of a certificate of public convenience and necessity to construct and operate the proposed Chesterfield Energy Reliability Center electric generation and related transmission facilities pursuant to §§ 56-580 D and 56-46.1 of the Code of Virginia and for approval of a rate adjustment clause, designated Rider CERC, under § 56-585.1 A 6 of the Code of Virginia, Volume 2 of 2 PUBLIC VERSION (March 3, 2025), Case No. PUR-2025-00037, *Application of Virginia Electric and Power Company for approval of a CPCN to construct/operate the proposed Chesterfield Energy Reliability Center electric, generation/transmission facilities and approval of designated Rider CERC.*

sought to mitigate and correct for utility market power dynamics by establishing competitive, all-source procurement frameworks.

Colorado provides a well-documented example of a competitive approach to all-source procurement. In its 2016–2017 Electric Resource Plan, Xcel Energy's Public Service Company of Colorado ran the nation's first large-scale "all-source" competitive solicitation, inviting bids from any generation technology to meet roughly 600 MW of new capacity. In response, the utility received an unprecedented 430 proposals for 238 distinct projects, more than six times its 2013 solicitation, including over 350 renewable or renewable-plus-storage offers. Wind and solar bids posted median prices of just $18/MWh and $30/MWh, respectively, and solar-plus-storage were only marginally higher.[69] The Colorado Public Utilities Commission (PUC) ultimately approved Xcel's preferred "Colorado Energy Plan," which leveraged those record-low bids to retire 660 MW of coal a decade early and invest $2.5 billion in 1,100 MW of new wind, 700 MW of solar, and 275 MW of battery storage, plus selective gas acquisitions, saving customers an estimated $213 million.[70] The Colorado experience demonstrated that an open, technology-neutral competitive procurement process can reveal market-driven portfolios that outcompete legacy utility-driven portfolios on both cost and risk, influencing regulators and utilities nationwide to explore the adoption of similar all-source procurement frameworks.

Informed by the Colorado case study, as well as other jurisdictions' experience with all-source procurement, the following elements have emerged as best practice:[71]

1. **Regulators should use the resource planning process to determine the technology-neutral procurement need.** Commissions should use resource planning proceedings to make an explicit determination of need but define that need in terms of the load forecast that needs to be met and existing plants that may need to be retired. This approach offers advantages over a specific, numeric capacity target and technology specification.
2. **Regulators should require utilities to conduct a competitive, all-source procurement process with robust bid evaluation.** Experience to date has demonstrated that the market for generation projects can provide robust responses to all-source RFPs. These utilities' system planning models appear to be capable of simultaneously evaluating multiple technologies against each other. The optimum mix of solar, wind, storage, and gas resources is more effectively selected based on actual bids, rather than in a generic evaluation prior to issuing single-source RFPs.

[69] David Roberts, "In Colorado, a glimpse of renewable energy's insanely cheap future: even with storage, new renewables beat existing coal," Vox, January 16, 2018.

[70] "Regulators approve Xcel Energy's Plan to Double Production of Renewable Electricity," Associated Press, August 28, 2018.

[71] For additional information on best practices related to all-source competitive procurement, please refer to: John Wilson, Mike O'Boyle, Ron Lehr, and Mark Detsky, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (Energy Innvoation and the Southern Alliance for Clean Energy, April 2020); Fredrich Kahrl and Lisa Shwartz, *All-Source Competitive Solicitations: State and Electric Utility Practices* (3rdRail, Inc. and Lawrence Berkeley National Laboratory, March 2021).

3. **Regulators should conduct an advanced review and approval of procurement assumptions and terms.** Though certain all-source procurements have been initiated without regulatory review and approval, experience suggests that Colorado's practice of a full regulatory review process in advance of procurement is optimal and highlights how utility regulators can proactively ensure that resource procurement follows from utility planning.
4. **Regulators should renew procedures to ensure that utility ownership of generation is not at odds with competitive bidding.** Most resource procurement practices include regulatory requirements or utility codes of conduct that restrict the sharing of information with utility-affiliated firms that may participate in the procurement. However, examples of bias toward self-build projects remain. An all-source procurement creates opportunities for large, self-built gas plants to compete against independently developed renewable or storage plants. Regulators should renew procedures that define appropriate utility participation when utility ownership is contemplated, considering that more complex bid evaluation processes can create additional opportunities for bias.
5. **Regulators should require the use of an independent examiner or evaluator to provide oversight and ensure the integrity of the competitive bidding process.** An independent evaluator can serve as an impartial monitor, validating whether the procurement follows established procedures, treats all bidders fairly, and maintains transparency throughout the evaluation process.

Virginia will likely need to add significant new generation and capacity in the years ahead to address growing load forecasts and support economic development in the state. Such resource additions, however, should not come at the expense of ratepayer affordability. All-source competitive procurements offer a way forward that can yield a cost-effective and optimized resource portfolio that is technology-agnostic in its approach. If undertaken, SCC attention would be needed to appropriately incorporate established best practices for Virginia's circumstances, including possible updates to related planning and approval activities (such as IRP and CPCN processes).

### Innovation Programs and Regulatory Sandboxes

At the heart of the unfolding energy transition is the need for innovation across the utility system. That entails innovation in many forms, ranging from new technologies and strategies for their integration, to program design and customer engagement, to innovation in the underlying regulatory structures themselves. Many jurisdictions recognize this and have developed programs or institutional arrangements to test and scale innovations in their various forms. These are sometimes considered under the banner of utility pilots or demonstration projects, but have started to reflect a recognition that small-scale pilots have tended not to take root or mature into system-wide offerings with broad value.[72] To address this challenge, some states and regulators have implemented various arrangements. These are sometimes referred to as a

[72] Courtney Fairbrother, Leia Guccione, Mike Henchen, and Anthony Teixeira, *Pathways for Innovation: The Role of Pilots and Demonstrations in Reinventing the Utility Business Model* (Rocky Mountain Institute, 2017).

**regulatory sandbox**, in which there is more intention to connect technology or program innovation with testing of alternative ratemaking structures.[73]

One example is Connecticut's Innovative Energy Solutions (IES) Program. The IES Program is managed under the authority of the state regulator (PURA in this case) and leverages ratepayer funds to attract third-party solutions to the state. Some projects are deployed in direct partnership and coordination with the utilities, while others are not directly integrated into the grid network. The IES Program is undertaking its third cycle of project solicitations and awards in 2025; two prior cycles support 15 awardees, eligible for between $150,000 and $2.7 million per award, paid based on agreed-upon project milestones.[74]

In addition to commission-hosted innovation programs and regulatory sandboxes, leading jurisdictions have continued to invest in other state-affiliated entities to foster energy system innovation and economic development. To that end, Connecticut boasts other quasi-government organizations that support energy system innovation, including the Connecticut Green Bank and Connecticut Innovations. New York State supports a similar ecosystem of energy system investment and innovation, largely supported by the New York State Energy Research and Development Authority (NYSERDA) and its NY Green Bank.

Given the strong imperative for innovation within the regulatory framework, Virginia should consider whether a regulatory sandbox program can deliver customer benefits and bring economic activity to the region. Moreover, Virginia should consider if there is an opportunity to support broader innovation investment through existing agencies and organizations, or if there is an interest in creating a new institutional structure. At their best, these arrangements tend to derive authority and reliable funding from legislative enactment, while their leadership receives clear mission direction but operates with functional independence from political and regulatory dynamics.

### Independent Energy Efficiency Utility

Energy efficiency is an identified priority in Virginia and was included in the Joint Resolution and received considerable attention in the Department-led stakeholder process. Other approaches to energy efficiency are available, in addition to the identified incentive mechanisms in the preceding sections that remove the throughput incentive (*i.e.*, decoupling) or provide targeted performance incentives. Namely, an independent energy efficiency utility would be a new institutional arrangement in which the role of customer-oriented energy efficiency program administration is granted to a separately chartered organization. In some cases, the scope for an energy efficiency utility has expanded to include other demand-side programs and clean

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[73] See, for example, Strategen's *Regulatory Sandboxes Program Design to Accelerate Innovation for an Evolving Electric Grid* (May 2022); Energy Transition Expertise Centre's *Study on Regulatory Sandboxes in the Energy Sector* (July 2023); and Lawrence Berkeley National Lab's *Regulatory Sandboxes and Other Processes to Expedite Utility Adoption of Advanced Grid Technologies* (June 2025); and Richard Kauzlarich (online workshop, "Energy, Economic Development, and Regulatory Sandboxes: Potential Possibilities and Challenges," George Mason University's Center for Energy Science and Policy at the Schar School of Policy and Government, August 22, 2024).

[74] "Innovative Energy Solutions Program: Accelerating Innovative Energy Partnerships in Connecticut," Connecticut Innovative Energy Solutions (website), accessed July 8, 2025.

energy supply options. This concept received some discussion among stakeholders in the Department process, and may be worth further evaluation by Virginia regulators and elected officials if clean energy and efficiency goals seem incompatible with utility business priorities.

Vermont was an early pioneer of a statewide independent energy efficiency utility when it established Efficiency Vermont in 1999 under operational management by the nonprofit Vermont Energy Investment Corporation. Efficiency Vermont claims $3.3 billion saved for Vermont energy customers and 14.1 million metric tons of carbon dioxide emissions savings, attributed to a range of programs including product rebates, energy assessments, consumer financing, and more.[75] This structure has taken root in many other jurisdictions, including Washington, DC and Maine. In each case, the government-chartered organization has used ratepayer funds to promote bill savings and clean energy programs that align with state policy and the conditions of the applicable customer demographics. In Maine, for example, a focus on heat pump adoption to reduce dependency on delivered fuel oil has resulted in nation-leading heat pump deployment while contributing to growth in electricity load.[76] In some cases, cities or counties within an IOU service territory have established similar efficiency or clean energy utilities to serve their residents and businesses. Those include Boulder County, Colorado and, as of fall 2024 by a citywide referendum, Ann Arbor, Michigan.[77]

An energy efficiency utility could help make progress on multiple priority outcomes for Virginia, including decarbonization, energy efficiency, bill management, and energy justice goals. It would also constitute a notable change in the Commonwealth's approach to efficiency and DSM delivery. New legislation would very likely be required to create a new organization, as well as identify its governance structures, funding, and primary objectives or mission.

## 3.5 Ratemaking Reform in Other Jurisdictions

States nationwide have adopted forms or components of PBR, providing a range of experience and examples over many years. This section describes the recent experience from selected jurisdictions to share details of those jurisdictions' design and implementation processes.

These reviews focus on jurisdictions that have adopted MRPs complemented by performance mechanisms because these best demonstrate the practical design and incentive structure decisions that Virginia may also consider, and best align with participants' interest as expressed during the Department's stakeholder engagement process. We do not describe states with more limited applications of individual PBR mechanisms or alternative ratemaking, such as decoupling or one-off PIMs, because these do not provide an integrated PBR approach, which is the focus of this review. Nonetheless, PBR mechanisms are widely employed across states

[75] "About: Our Results", Efficiency Vermont, accessed July 29, 2025.

[76] Maine Climate Council, *Maine Won't Wait* (November 2024).

[77] "Residential Sustainability – EnergySmart," Boulder County, accessed July 8, 2025; "Ann Arbor's Sustainable Energy Utility," City of Ann Arbor, accessed July 8, 2025.

and utilities beyond those discussed here and offer numerous additional case studies that can be examined to inform the design of individual elements.[78]

The examples described below—provided in alphabetical order—reveal a common, if evident, conclusion: design matters. Furthermore, the process by which the PBR structure is created also matters. In other words, it's not just a matter of *what* is prescribed in legislation or *which* PBR mechanisms are employed, but also *how* the mechanisms get developed. Together, these and other factors influence the degree to which the resulting regulatory structure and its embedded incentives do or do not shift utility attention to the achievement of regulatory objectives.

### Connecticut

Connecticut is creating what may be among the most comprehensive PBR frameworks in the US, with final decisions expected by September 2025.[79] These decisions will culminate in a robust PBR structure, the framework for which was laid out by the Connecticut Public Utilities Regulatory Authority (PURA) in 2023, following legislative authorization from Public Act No. 20-5 in 2020. PURA adopted this framework, building on the development of PBR elements in other jurisdictions, with a focus on affordability, given the high retail rates in the state, as well as heightened reliability concerns following electric service outages in 2020 due to Tropical Storm Isaias.[80]

The net effects of Connecticut's expected PBR framework will likely take some years to assess fully. At the outset, however, it is evident through the scope of the proceeding and evaluation process that PURA seeks to meaningfully evolve the state's regulatory framework beyond traditional COSR following an approach developed via an intensive, several-years-long engagement effort.

Connecticut's retail energy rates are among the highest in the country, which has led PURA to design a PBR framework that includes strong cost-containment measures while maintaining stable utility funding for necessary investments across a four-year MRP term.

During the process of creating specific PBR mechanisms, Connecticut utilities emphasized their desire for a capital funding mechanism to support grid expansion projects that could be recovered outside the index-based MRP structure.[81] Following consideration by PURA and intervenors, the resulting PBR framework will include these future capex costs in the revenue-

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[78] See, for example, Appendix A of Guidehouse (2020), prepared for Edison Electric Institute; "Electricity Regulation for a Customer-Centric Future: Survey of Alternative Regulatory Mechanisms."

[79] Decisions are expected in PURA Docket Nos. 21-05-15RE01, 21-05-15RE02, and 21-05-15RE03 in September 2025. These proceedings represent Phase II of Connecticut's PBR process, and are focused on the development of revenue adjustment mechanisms, performance mechanisms, and PBR within the context of integrated distribution system planning.

[80] PURA, Decision, (April 26, 2023), Docket No. 21-05-15, *PURA Investigation into a Performance-based regulation framework for the electric distribution companies*.

[81] PURA, Revised Straw Proposal (February 27, 2024), p. 21–23, Docket No. 21-05-15RE02, *PURA investigation into performance mechanisms for a performance-based regulation*.

capped MRP structure and retain these in base rates. The approach ties the utilities' additional capital funding to their projected infrastructure needs in their Integrated Distribution System Plan.[82] PURA has also proposed a mix of PIMs that are designed to incentivize exemplary performance through upside rewards and discourage substandard performance through downside penalties.[83]

Connecticut's approach to PBR demonstrates a holistic undertaking to review the integrated nature of the regulatory system and its embedded incentives. Connecticut's comprehensive PBR aims to address and mitigate misaligned utility incentives, such as capital expenditure bias, gold plating, and preferences for utility ownership. These issues can persist when COSR is adjusted with limited PBR interventions because individual PBR mechanisms may fail to adequately control overall utility costs if they do not work in conjunction with other structures. In contrast, a holistic PBR framework can harness a well-designed suite of complementary regulatory mechanisms to create more significant incentives for cost control and other exemplary utility performance.

### Hawaii

Hawaii initiated comprehensive PBR reforms beginning in 2018, leading to a set of practices and an updated regulatory system to institute more integrated incentive regulation.[84] After more than two years of working group meetings, workshops, and briefings, Hawaii implemented a PBR framework based on a set of regulatory principles and objectives that the Hawaii PUC outlined early in the process.[85]

Hawaii's PBR framework is designed to support the selection and implementation of the most cost-effective energy solutions that meet the state's energy policy goals and objectives, which were identified via Phase 1 of Hawaii's PBR proceeding.[86] It encourages energy solutions that prioritize effective and economic options, regardless of whether they are owned by utilities or independent providers. Additionally, the PBR framework adopts PIMs that encourage utilities to enhance their performance in areas aligned with Hawaii's broader energy policy objectives.

Hawaii's PBR framework also offers the potential for more affordable customer rates and accelerates the adoption and integration of renewable energy technologies. Finally, Hawaii PBR provides electric utility companies with an opportunity to increase their profit by effectively managing costs and achieving high-performance outcomes that are important to the state and its customers.

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[82] Revised Straw Proposal p. 33–38.

[83] Revised Straw Proposal p. 12–13.

[84] Information about Hawaii's PBR reform process is available on the Hawaii PUC's webpage dedicated to the proceeding: "Performance-Based Regulation (PBR) for the Hawaiian Electric Companies (Docket No. 2018-0088)."

[85] Hawaii Public Service Commission, Decision and Order No. 37507 (December 23, 2020), p. 14–17, Docket No. 2018-0088, *In the Matter of Instituting a Proceeding to Investigate Performance-Based Regulation*.

[86] Hawaii Public Service Commission, Decision and Order No. 36326 (May 23, 2019), p. 5–7, Docket No. 2018-0088, *Instituting a Proceeding to Investigate Performance-based Regulation.*

Hawaii's PBR framework employs four types of regulatory tools:

1. *Revenue adjustment mechanisms*, which establish the utility's target revenues for a five-year MRP. Target revenues are adjusted by an index-based formula that takes into account inflation, collected revenues, and extraordinary projects, as well as a customer dividend that reduces rate impacts.
2. *Performance mechanisms*, including PIMs that provide additional revenue opportunities if the utility meets certain performance outcomes, supplemented by a portfolio of scorecards and reported metrics to monitor the utility's progress.
3. An innovative *pilot process* including a framework for expedited review of pilots that are intended to incentivize outcome-aligned programs and projects.
4. *Safeguards* including an ESM to protect the utility and customers from excessive earnings or losses, and a reopener mechanism in the event that parts of the PBR framework need to be reexamined.

The Hawaii PBR framework went into effect on June 1, 2021, for a five-year MRP period. During this period, the parties involved in developing the comprehensive regulatory framework have continued to collaborate through Hawaii's PBR Working Group on implementation and monitoring efforts, including the development, review, and modification of PIMs.[87] In the final years of the five-year MRP, the Hawaii PUC and stakeholders will review the PBR framework to determine appropriate modifications for the next MRP period.[88]

### Maryland

In 2020, the Maryland Public Service Commission (PSC) established a pilot MRP framework for electric and gas utilities, following a broader initiative in which the Maryland PSC sought stakeholder feedback on alternative ratemaking approaches and strategies.[89] The pilot sought to test MRPs paired with integrated PBR elements, including decoupling, metrics, and incentives.

The PSC subsequently approved three-year pilot MRPs for three Exelon utilities—Baltimore Gas and Electric Company, Pepco, and Delmarva Power. Following the pilot MRP experience, Baltimore Gas and Electric was approved for a second three-year MRP (2024–2026), while

[87] See Hawaii PSC filings listed on the PSC's webpage dedicated to its PBR process.

[88] Hawaii Public Service Commission, Order No. 40852, Providing preliminary guidance regarding the comprehensive review of the performance-based regulation framework (June 19, 2024), Docket No. 2018-0088, Instituting a Proceeding To Investigate Performance-Based Regulation.

[89] Maryland PSC, Order No. 89482, Order Establishing Multi-year Rate Plan Pilot (February 4, 2020), Case No. 9618, *In the matter of alternative rate plans or methodologies to establish new base rates for an electric company or gas company.*

Maryland Public Service Commission, Notice of Technical Conference on Alternative Forms of Rate Regulation (February 14, 2019), PC51, Exploring the use of alternative rate plans or methodologies to establish new base rates for an electric company or gas company.

Pepco's proposal to continue its MRP was denied, due in part to criticism from intervening advocates about a lack of appropriate cost control measures within the MRP.[90]

Although Maryland has adopted multi-year stayout periods for some utilities, the MRPs do not apply meaningful cost discipline on the utilities and thus have been criticized as misaligned with PBR objectives. Most notably, the multi-year stayout periods incorporate numerous features to true up utility revenues midperiod, including a revenue reconciliation rider at the start of each year. This structure neutralizes the revenue cap because cost overruns are adjusted into customer rates and, consequently, the need for cost containment is seriously dampened. During the development process for the stayout periods and subsequent reviews, several Maryland parties expressed concerns regarding this approach, as well as for challenges that result from information asymmetries utilities use to their advantage in constructing cost forecasts.[91] More recently, intervening parties have expressed that MRPs "have not achieved rate stability [in Maryland]," further noting that "there appears to be a continuous increase in budget forecasts between [MRPs] and actual utility expenditures," among other concerns regarding costs to ratepayers.[92]

The practical effect of Maryland's approach to MRPs is more akin to formula rates than performance-based rates. Maryland's experience has created serious skepticism of PBRs in that state.[93] This demonstrates the importance of designing any ratemaking structure with careful attention to the embedded incentives (or diminishment thereof) that the accumulation of small decisions or automatic adjustments can create.

In 2025, Maryland passed legislation that seeks to address some of these shortcomings. The legislative updates require that future MRPs must demonstrate clear customer benefits, and plans should not include mid-plan cost or revenue reconciliation.[94]

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[90] Maryland Office of People's Counsel, "In a win for customers, State regulators reject Pepco plan for three years of rate increases," June 11, 2024.

[91] Maryland Office of People's Council, Comments of the Maryland Office of People's Counsel on Chief Public Utility La Judge Ryan C. McLean's Implementation Report (January 17, 2020), Case No. 9618, *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for An Electric or Gas Company*; Baltimore Gas and Electric filing, Initial Comments of Baltimore Gas and Electric *Company* (September 16, 2024), Case No. 9645, *Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan*.

[92] Maryland Energy Administration, Comments of the Maryland Energy Administration on Multi-Year Rate Plans (September 16, 2024), Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for An Electric or Gas Company; Baltimore Gas and Electric filing, Initial Comments of Baltimore Gas and Electric Company (September 16, 2024), Case No. 9645, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan.

Maryland Public Service Commission, Order on Application for a Multi-Year Rate Plan (June 10, 2024), Case No. 9702, *Potomac Electric Power Company's Application for Adjustments to its Retail Rates for the Distribution of Electric Energy*.

[93] Maryland Office of People's Council (September 16, 2024).

[94] Maryland House Bill 1035 (2025).

It remains to be seen how the recent legislative updates, in addition to suggestions from interested parties, will be factored into future MRPs in Maryland. Although the experience in Maryland demonstrates vulnerabilities in PBR structures, it also offers valuable lessons regarding the importance of well-constructed PBR mechanisms and the "pilot" approach is a recognition that all reforms require iteration and update as experience is gained.

### North Carolina

North Carolina adopted procedures and requirements for PBR in 2022 following passage of House Bill 951 (incorporated as North Carolina § 62-133.16), which authorized the North Carolina Utilities Commission (NCUC) to do so. This followed years of stakeholder advocacy for PBR, as well as a North Carolina Department of Environmental Quality-led stakeholder process in 2020 to contemplate grid needs and possible reforms—similar in some respects to the Virginia Department of Energy process that was held in 2024–2025.

House Bill 951 authorized the NCUC to approve utility-submitted PBR applications if those applications include specific PBR requirements, including MRPs up to three years, decoupling, PIMs, and an ESM. In North Carolina's case, the NCUC was tasked with determining additional minimum requirements for PBR (beyond those outlined in House Bill 951), which the NCUC developed via a dedicated rulemaking proceeding.[95] Following the establishment of that general framework, specific details of the ratemaking structures were reserved for the utilities to propose in their own PBR plans.[96]

Two utilities in North Carolina, Duke Energy Progress and Duke Energy Carolinas, proposed PBR plans that were subsequently adopted by the NCUC. The utilities' PBR plans meet the House Bill 951 requirements as well as the NCUC requirements, but the plans' abilities to induce meaningful incentive realignment for the utilities—particularly in regard to cost containment—is limited.

These limitations are partly due to information asymmetries, by which utilities have more understanding of system needs and associated costs than others, thus putting commissions at a disadvantage in evaluating cost proposals without sufficient transparency in cost calculations.[97] The North Carolina PBR approach also departs from best practice in other ways, including an option for utilities to file a rate case mid-stayout period if their ROE falls below authorized levels.[98] Annual true-ups (reconciliation) are also permitted, similar to Maryland, which creates a further pressure and can let the utility avoid more significant cost efficiency. These limitations

[95] The NCUC developed rules for PBR in North Carolina via a dedicated proceeding, Docket No. E-100, Sub 178, *In the Matter of Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities*. The NCUC issued an order adopting PBR rules (Commission Rule R1-17b) on February 10, 2022 and NCUC Public Staff issued a petition to amend those rules on September 20, 2024.

[96] N.C. Gen. Stat. § 62-133.16.

[97] Synapse Energy Economics, *Implementing PBR with Customer Protections in North Carolina*, prepared for the Carolina Utility Customers Association, (November 2021).

[98] Synapse Energy Economics (November 2021).

are heightened as a result of language in North Carolina's enabling legislation that *permits* (but does not require) electric utilities to propose PBR plans.[99]

Although several parties, including clean energy advocates, expressed support for PBR more broadly, they also expressed concern that North Carolina's approach limits regulators' authority and favors utilities over ratepayers, and that the MRP approach described in House Bill 951 does not encourage cost containment.[100] North Carolina intervenors also criticized the PBR plans as not sufficiently aligning utility incentives and enforcement with clean energy goals or other identified objectives.[101]

North Carolina's experience with PBR illuminates the importance of regulator-directed mechanism design to support best practices application and create a robust PBR framework. These and other limitations of North Carolina's PBR approach were also raised during the Virginia Department of Energy process in 2025.[102] North Carolina's experience also underscores the need to design ratemaking structures in concert with other features of the regulatory system through a regulatory process in which straw proposals and frameworks are the result of an iterative and collaborative engagement process that allows utilities and intervening parties to offer their own design proposals for commission consideration.

### Experience Outside the US

Several jurisdictions outside the US have employed performance-based regulation, with valuable experience and some demonstrated success that can inform US applications. In many respects, these jurisdictions have moved ahead to more comprehensive PBR and are now in periods of refinement to continually update and hone the regulatory systems.

Most prominent of these is the United Kingdom's RIIO regulatory model. RIIO stands for "Revenue = Incentives + Innovation + Outputs" and is composed of numerous PBR mechanisms, including MRPs, benchmarking, ESMs, and PIMs. The administration of these mechanisms is closely integrated and subject to significant regulatory review and negotiation between the regulator (Ofgem) and the regulated companies. RIIO was created during an intensive design period, in the late 2000s to early 2010s, and produced regulatory schemes for regulated companies in each of the sectors for electricity distribution, electricity transmission, and gas distribution. The program relies on detailed company-prepared proposals of multi-year financial plans for their future investment and operational needs, which Ofgem reviews to either accept or reject (with opportunities for updates by the utility). When accepted, the approved revenues govern a "price control" period during which utilities have the opportunity to seek cost

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[99] N.C. Gen. Stat. § 62-133.16: "An electric public utility shall be permitted to submit a PBR application…"

[100] "Duke-Backed Energy Bill Prioritizes Utility Influence Over Public Interest," Vote Solar (October 4, 2021); "Low-income neighbors need NC's help with energy bill burden," Sierra Club (October 20, 2021).

[101] See, for example, Carolinas Clean Energy Business Association (CCEBA), filed June 9, 2023 in North Carolina Docket No. E-2, Sub 1300: *Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*.

[102] RMI, *Examples & Lessons Learned from PBR in Practice*, presented to Virginia workshop on January 17, 2025.

efficiencies and keep a portion of savings. The first RIIO price control period was seven years—spanning 2013–2021 for transmission network companies ("RIIO-T1") and 2015–2023 for electric distribution companies ("RIIO-ED1"). Following that experience, Ofgem determined that a five-year control period was more appropriate to allow review and reset of rates sooner. As a result, RIIO-T2 is running from 2021 to 2026 and RIIO-ED2 from 2023 to 2028.[103]

The RIIO model applies totex ratemaking at its core to meaningfully equalize electric companies' self-interest in capital versus operating expenditures. As described elsewhere, totex remakes the revenue formula by collecting all capital expenditures and controllable operating expenses into a single total expenditure account.[104] A portion of this totex account is categorized as "slow money" and earns a rate of return. In RIIO, the capitalization rate is set independently for each company but generally ranges between 70 and 80 percent of expenditures that are allocated to slow money and eligible for a return.[105] A depreciation rate is set for assumed average lifetimes of system assets, with one asset lifetime assumed for distribution network companies and a longer lifetime for transmission companies. To encourage cost savings within the control period, a "totex incentive mechanism" lets companies retain a predetermined percentage of any cost savings below the allowed revenue, while the same percentage applies (*i.e.*, symmetric design) in the case of overspend for costs borne by the company. In this manner, the incentive mechanism functions like an SSM. RIIO's totex-based approach is credited with reorienting network companies in the United Kingdom to be more open to partnerships and to help remake themselves into network integrators rather than singular monopoly service providers.

Australia has also pursued wide-ranging reforms over more than a decade, with the purpose of integrating DERs, decarbonizing the economy, and achieving cost efficiency. Similar to Great Britain, a prominent feature in the Australia regulatory structure is a focus on capex-opex equalization in the form of a calibrated ECM. The calibrated ECM is instituted through a capital expenditure sharing scheme in place since 2013 (for capital expenses) and an efficiency benefit sharing scheme for operating expenses since 2007 (for operating expenses), both of which are included in their five-year MRPs. The respective mechanisms are designed to reflect the character and circumstances of operating versus capital costs, but collectively they allow the utility to retain a share of savings below baseline forecasted levels. A 2022 analysis found that $13.4 billion in customer savings were attributable to these and other performance structures in Australia, from which the most significant share was due to the operating expense sharing mechanism.[106]

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[103] "Network price controls 2021-2028 (RIIO-2)," Ofgem, accessed July 24, 2025.

[104] Under the RIIO model, costs considered to be outside of a company's control (*e.g.*, taxes and pension expenses) area treated separately.

[105] Oxera, *Methodology review for a regulatory framework based on a total expenditure approach ('ROSS-base')* (December 2021), prepared for Autorità di Regolazione per Energia Reti e Ambiente.

[106] HoustonKemp Economists, Consumer benefits resulting from the AER's incentive schemes (March 2022), prepared for Energy Networks Australia.

In Canada, the Alberta Utilities Commission is in its third term of PBR-based MRPs. These have applied five-year stayout periods with a set of indexed adjustments including for inflation and both an X-factor and an “X-factor premium” to encourage productivity improvements. An ESM is also applied to share costs and benefits between the utilities and ratepayers. The Alberta experience has been remarkably stable, now approaching 15 years through three MRP periods, due in part to regulator stability to manage and maintain the system.

These and many more jurisdictions provide useful lessons and experience to draw from. They indicate that MRP-based performance regulation is compatible with continued utility health and prosperity, as well as reliable service to customers. From these examples, a five-year MRP duration emerges as a favored length (long enough to allow utility pursuit of objectives, but not too long without a full review). These examples also demonstrate a diversity of associated factors, integrated structures, and design considerations that must be sufficiently evaluated to build a well-performing regulatory system. In each case, they reveal a deep and sustained commitment by regulators and the surrounding community to build, monitor, and refine regulations in pursuit of better outcomes. As US states undertake specific reforms—whether a capex-opex equalization strategy, an MRP, or others—they may consider looking to models and specific mechanical structures that are used abroad, which can be investigated further to inform design in the US.

### Takeaways

The experience in these jurisdictions reveals some general lessons that should be considered in Virginia or anywhere that pursues PBR and regulatory reform. Those include:

- The importance of **outcome-oriented design**, by which a combination of policymaker or regulator direction and stakeholder input establishes an identifiable set of priority outcomes or performance areas that serve as the primary objectives for subsequent reforms.
- A need for **regulator leadership** to set the ingoing vision and parameters by which a PBR framework and eventual details are created. Generally speaking, a regulator-led policy proceeding, with commission-initiated proposals followed by opportunities for utility and intervenor refinement, is a good approach to create balanced and effective reforms.
- Attention to **MRP details that induce meaningful performance**, including cost containment. MRPs with index-based adjustments can balance utility revenue stability with expectations for cost containment and investment efficiency, whereas multi-year stayout periods that are overly reliant on automatic adjusters (or riders such as RACs) can serve as vehicles for risk avoidance without forcing enough attention to prudency.
- Careful attention to the **interactive effects of the full regulatory system** and its embedded incentives. As for any regulatory approach, PBR development requires careful and continued attention to other major policies, structures, and processes that utilities are subject to, including alignment with state policy, resource planning processes, and the cycle of rate cases. If structures in one part of the regulatory ecosystem do not reflect upon, and in some cases directly account for, investment plans and activities that appear elsewhere, then there is a high risk that these efforts become

incongruent with each other, or worse, there is a potential for manipulation between various elements.

## 3.6 Competitive Service Providers and Carbon Leakage from the Manufacturing Sector

In addition to the PBR analysis conducted above, the Joint Resolution directs the SCC to consider factors related to competitive service providers (CSPs) and the potential for carbon leakage in the manufacturing sector in its study. Specifically, it directs the Department and the SCC to complete the following with respect to CSPs and carbon leakage in the manufacturing sector:

- Study the impact of CSPs in Virginia
- Evaluate potential impacts of PBR and other alternative regulation tools on CSPs in Virginia
- Analyze Virginia's current regulatory framework, as well as the financial incentives that the current regulatory framework creates for Virginia's IOUs (completed above) and CSPs
- Identify different obligations for Virginia's IOUs and CSPs
- Consider whether PBR and/or other alternative regulatory tools might prevent carbon leakage in the manufacturing sector

Considerations related to CSPs and carbon leakage from the manufacturing sector are not commonly targeted via PBR frameworks and may not be directly addressed by standard PBR tools. PBR may not be suitable to directly incentivize decisions by these nonutility actors, but there are opportunities to improve regulatory incentive structures to support these objectives such as improvements to planning and resource procurement, and levelizing earning opportunities between capital and operating expenditures to encourage least-cost or highest-value solutions to be selected. Though implementing a more comprehensive PBR framework for Virginia's electric IOUs would have minimal implications related to carbon leakage from the manufacturing sector or the operation of CSPs, we summarize the current regulatory context and discuss potential implications of PBR on both of these topics below, in accordance with the Joint Resolution directives.

### Competitive Service Providers

*Legislative and Regulatory Context*

The Joint Resolution defines CSPs more broadly than the definition used elsewhere in Virginia statute (Virginia Administrative Code 20VAC5-312-10). The Joint Resolution defines CSPs as "entities with generation *or* transmission *and* licensed suppliers that sell electricity to end-of-use customers" (emphasis added).[107] Comparatively, Virginia Administrative Code 20VAC5-312-10 defines CSPs based on the sale of competitive energy service, based on how it defines

[107] Virginia General Assembly, Joint Resolution.

"aggregator," "competitive energy service," and "competitive service provider" as provided below:[108]

- *Aggregator:* "A person licensed by the State Corporation Commission that, as an agent or intermediary, (i) offers to purchase, or purchases, electricity or natural gas supply service, or both, or (ii) offers to arrange for, or arranges for, the purchase of electricity supply service or natural gas supply service, or both, for sale to, or on behalf of, two or more retail customers not controlled by or under common control with such person."
- *Competitive energy service:* "The retail sale of electricity supply service, natural gas supply service, or any other competitive service as provided by legislation and approved by the State Corporation Commission as part of retail access by an entity other than the local distribution company as a regulated utility. For the purpose of this chapter, competitive energy services include services provided to retail customers by aggregators."
- *CSP:* "A person, licensed by the State Corporation Commission, that sells or offers to sell a competitive energy service within the Commonwealth. This term includes affiliated competitive service providers, as defined above, but does not include a party that supplies electricity or natural gas, or both, exclusively for its own consumption or the consumption of one or more of its affiliates. For the purpose of this chapter, competitive service providers include aggregators."

While 20VAC5-312-10 defines CSPs based on the sale of competitive energy service, the Joint Resolution more broadly encompasses entities that either generate or transmit electricity, in addition to those who sell electricity to end users.

SCC has licensing authority over CSPs subject to the definition under Virginia Administrative Code 20VAC5-312-10, though these CSPs are not rate-regulated in Virginia. To receive a license to operate in Virginia, CSPs must demonstrate "financial fitness commensurate with the service or services proposed to be provided" by submitting an application identifying specific business, operational, and financial information to the SCC for review and approval, and by demonstrating to the SCC that they have the technical capability to deliver and sell electricity to retail customers. CSPs are also subject to regular reporting requirements.[109] Comparatively, electric IOUs in Virginia are subject to extensive regulatory oversight by the SCC and in accordance with legislative parameters including the Regulation Act and the VCEA.

More than 100 CSPs (including aggregators) are currently authorized to sell electricity in Virginia. These CSPs offer a range of services, including retail electricity sales to commercial, industrial, and/or residential customers within a specific IOU's service territory, a cooperative provider's service territory, or statewide.[110]

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[108] 20 Va. Admin. Code 5-312-10.

[109] "Fact Sheets: Choosing an Energy Supplier," Virginia State Corporation Commission, accessed June 9, 2025.

[110] "Competitive Service Providers and Aggregators," Virginia State Corporation Commission, accessed June 9, 2025.

### *Analysis of Potential CSP Impacts*

As summarized in the Department's stakeholder engagement report, CSPs were a topic of discussion during Meeting 7. Presenters at that meeting emphasized that due to the competitive, market-sensitive nature of CSPs (unlike IOUs, which operate as regulated monopolies), performance-based regulation of CSPs is not necessary. The Department provided opportunities to further discuss considerations such as how a PBR framework might impact CSPs, and what might be challenging about applying a PBR framework to CSPs in an environment in which the CSPs are not rate-regulated. However, participants did not choose to discuss these factors in detail.

Because the SCC's regulatory authority over CSPs as defined under Virginia Administrative Code 20VAC5-312-10 is largely limited to licensing, it is unlikely that implementation or expansion of PBR or other alternative regulatory tools would impact CSPs in any significant manner. However, the broader definition of CSPs under the Joint Resolution includes any entities that generate or transmit electricity, or any entities that sell electricity directly to end-use customers, which would include (but not be limited to) electric IOUs. Implementing or expanding PBR frameworks in Virginia would have little impact on CSPs as defined under Virginia Administrative Code 20VAC5-312-10, and potential implications of CSPs in rate-regulated IOU contexts in Virginia are described throughout this report.

## Carbon Leakage in the Manufacturing Sector

### *Legislative and Regulatory Context*

The Joint Resolution directs the SCC to "consider whether and how [PBR or alternative regulatory] tools assist in preventing carbon leakage from the manufacturing sector."[111] In the industrial context, "carbon leakage" refers to an instance in which a carbon-emitting industry moves some or all of its operations to a jurisdiction with less strict emissions standards or policies. This may lead to emissions reductions in the jurisdiction in which the industry previously operated but can lead to increased greenhouse gas emissions overall.[112] Carbon leakage typically refers to changes in emissions trends between countries, but can apply to other jurisdictional movements such as between states.

Carbon leakage in the manufacturing sector was a topic of discussion during Meeting 8, as summarized in the Department's stakeholder engagement report. At this meeting, participants had an opportunity to discuss any concerns they had related to carbon leakage. While participants did not choose to discuss the topic during the meeting, one group submitted written comments in which they stated that an evaluation of energy-intensive industries in California and the European Union, as well as the ratemaking structures under which those industries operate, should be included when developing a PBR construct.

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[111] Virginia General Assembly, Joint Resolution.

[112] What is Carbon Leakage?" UC Davis CLEAR Center, accessed April 24, 2025.

As previously described, the RPS requirements established under the VCEA require that Dominion achieve 100 percent carbon-free electricity by 2045, and that APCo achieve 100 percent carbon-free electricity by 2050.[113] Although this requirement does not pertain specifically to manufacturers, it does apply to the electricity these manufacturers require for operations. Additionally, the Regulation Act establishes that several RACs (such as RACs related to vegetation management or the construction of new underground electric facilities) cannot be applied to customers under the large general service rate classes for Dominion or APCo. Entities enrolled in such a rate typically include high-use customers such as very large industrial customers.

#### *Analysis of Potential for Carbon Leakage from the Manufacturing Sector*

Utility regulations, including PBR or other incentives, have an indirect relation to potential carbon leakage from the manufacturing sector. Many manufacturers and other large industrial customers are highly sensitive to the cost of electricity, and as a consequence those customers sometimes make decisions on where to locate based on the price of electricity. In a period of rising electricity costs, this determinant is increasingly important to businesses. If manufacturers opt to leave Virginia in pursuit of lower electricity costs, carbon leakage could indeed occur—but only if the alternative location has higher carbon intensity. However, it is also plausible that the location with lower electricity costs could have lower-carbon-intensity electricity, especially in light of declining costs observed from renewable energy sources. This dynamic adds to the importance of ensuring that affordability and cost containment are embedded in utility regulations. In light of this, a performance-based structure that centers cost containment as a core tenet of achieving state policy for renewable energy can provide an important insulation against the risk of carbon leakage.

As discussed throughout this report, a revised regulatory framework that strongly encourages cautious and prudent utility investments can lead to reduced costs over time, including for manufacturers. Additionally, as a retail choice state, manufacturers have options to pursue lower-cost electricity service because they can obtain electricity through a licensed CSP rather than relocating operations to another jurisdiction. Regardless, it is important that when developing a PBR framework, regulators consider the potential for unintended secondary or tertiary consequences to protect against undesired outcomes such as carbon leakage to other jurisdictions due to manufacturers leaving Virginia.

[113] Code § 56-585.5.