Virginia Regulatory Assessment Template

**Instructions:**

* Select one (1) “performance area” or outcome from the following set to evaluate how existing regulatory mechanisms in Virginia support (incentivize) the achievement of that outcome or disincentivize the achievement of the outcome. Consider this question for each regulatory mechanism identified in the template, and for the overall performance of Virginia’s utility regulatory structure to support (or hinder) that outcome (performance area).
* Each stakeholder should complete worksheets for at least two performance areas of their choosing. Additional (more than two) performance areas can be evaluated in additional worksheets, at your discretion.

**Cost-efficient utility investments and operations and affordability**

One of the mandates in the enabling legislation is evaluating the potential of performance-based regulatory tools and alternative regulatory tools to assist in the regulation of investor-owned electric utilities by “(ii) enhancing cost-containment incentives.” This regulatory assessment shines light on how different mechanisms enhance or undermine cost-containment incentives for investor-owned utilities and how the system disincentivizes or incentivizes cost-efficient utility investments. Since efficient utility management has a direct impact on affordability, this assessment also serves as an evaluation of the affordability performance area.

An electricity affordability crisis in Appalachian Power Company (APCo)’s service territory has been building for almost two decades. According to the State Corporation Commission (SCC), “APCo's typical monthly residential bill was $66.61 as of July 1, 2007. The bill has increased by $105.48 (158.36%) to $172.09 per month as of July 1, 2024.”[[1]](#footnote-1) Increasing electricity bills are a pressing regional issue in APCo territory. For Dominion Energy Virginia, “the typical monthly residential bill was $90.59 as of July 1, 2007. The bill has increased by $43.15 (47.63%) to $133.74 per month as of July 1, 2024.”[[2]](#footnote-2) For both utilities, the RAC component of the bill experienced the largest increase over this period. By year-end 2035, Dominion Energy projected in its 2024 IRP that a typical residential customer will pay $215.62, assuming that increased costs mostly associated with data center load growth are allocated to data center customers. Without that assumption, Dominion projects that the typical residential customer could end up paying $315.25 per month in 2035.[[3]](#footnote-3) These average bill increases affect households the most when electricity usage is higher in winter and summer months. Increasing electricity costs merit an evaluation of the current Virginia rate-making structure and its impact on cost-containment incentives. Finally, without a firm commitment by the utilities to energy efficiency and peak load reduction for residential customers, general price increases will continue undermining customer affordability during critical parts of the year when consumption is highest.

**Reference Key:** Performance Areas from *House Joint Resolution No. 30 / Senate Joint Resolution No. 47*

|  |  |
| --- | --- |
| Reliability and resiliency | Affordability for customers |
| Emergency response and safety | Cost-efficient utility investments and operations |
| Peak demand reductions | Maximization of available federal funding |
| Cyber and physical security of the grid | Savings maximization from energy efficiency and exceedance of statutorily required savings levels |
| 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 | DER integration and speed of interconnection |
| Customer service | Beneficial electrification |
| Environmental justice and equity | Electricity decarbonization |

**Regulatory Assessment**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Outcome** | What regulatory *outcome* or *performance area* does this assessment consider? | | **Cost-efficient utility investments and operations and affordability** | | |
| **Do the existing regulatory mechanisms and programs sufficiently support the outcome?** | | | | | |
| **Key** |  | | | | |
| **+** | **Yes** | The mechanism or program **incents achievement** of this outcome. | | | |
| **0** | **No Impact** | The mechanism or program **does not seem to impact the achievement** of this outcome. | | | |
| **-** | **No** | The mechanism or program **disincentivizes the achievement** of this outcome. | | | |
| **Existing Regulatory Mechanisms and Programs** | **Description** | **Mechanism or Program’s Effect on Outcome** | | | **Issues for Attention** |
| **Score (+/0/-)** | | **Discussion** |
| **Rate Reviews (typically biennial)** | Rates are reset every two years. |  | | Frequent rate cases erode cost-containment incentives for the utility and increase regulatory burden. Thus, it does not favor the outcomes under evaluation.  Virginia regulated utilities have experienced different stay-out periods (time between rate cases). From the passage of the Re-regulation Act in 2007 through 2015, utilities were subject to biennial reviews, until SB1349, enacted in 2015, imposed a seven-year rate freeze that lasted through 2021. The 2018 Grid Modernization Act re-established triennial reviews that only applied for APCo during its 2023 rate case. Subsequent legislation in 2023 reinstated biennial reviews. APCo had its first biennial review in 2024 and Dominion had its first biennial review in 2023. From 2023 on, each utility will have a major rate case every other year. These regulations do not apply for Kentucky Utilities, the third Virginia investor-owned utility that is subject to traditional Chapter 10 regulations.  The longer stay-out period between 2015 and 2021 generated large overearnings for utilities that mostly did not come from efficiency gains. This occurred for multiple reasons: 1) During the 2015 rate case, the Commission was not allowed to update rates to reflect reduced cost of service; 2) during this rate freeze period, the reduction in the depreciation expense accumulated, generating overearnings for the utilities that were not used up by new costs. Instead, new costs were added on top of the base rate through rate adjustment clauses. However, under a system where most utility costs are recovered through base rates, the reduction in the depreciation expense would have been netted out with the new costs. | Longer stay-out periods have the potential to incentivize cost containment if designed well. A model developed by Pacific Economics Group found that utility long-run cost performance on average improves 0.51% more rapidly each year in an MRP with a five-year term and no earnings sharing than it does under traditional regulation when rate cases occur every three years.[[4]](#footnote-4)  Resetting a utility’s rates every two years reduces regulatory lag (i.e., the time between rate cases). Regulatory lag has traditionally served as a powerful incentive for cost efficiencies. Once rates are set, a utility’s earnings are higher if it can control costs. Conversely, if utility costs increase above revenues, profits will fall. Under the current two-year rate period, there is little incentive for the utility to control costs because if it overspends, it only has to wait a year until rates are reset.  A rate review every two years creates cost and time burden on regulators and intervening parties. The fact that reviews are frequent does not mean that stakeholders have the capacity for thorough quality scrutiny of utilities’ business decisions every time. Participation in frequent litigation cases is prohibitively expensive. While utilities can spend almost unlimited resources on litigation, since ratepayers have to pay for the utilities’ litigation expenses, this is not the case for other intervenors with much more limited resources and litigation capacity. Biennial reviews versus, for example, reviews that occur every three years significantly increase litigation expenses for intervening parties trying to cover both utilities. For example, entities like the Office of the Attorney General, which is charged with protecting ratepayers of all utility services, cannot double or triple their litigation budgets as easily as the utilities. The same applies for other intervenors with much more limited budgets that often represent the interests of residential customers and communities affected by utilities’ infrastructure plans. Thus, frequent reviews do not necessarily mean more accountability. On the contrary, the increasing litigation intensity necessary for utility regulation reduces intervenors’ capacity and risks thinning the depth of scrutiny. Furthermore, cases are often settled, which means that many of the issues that are intensely scrutinized by SCC staff and intervenors are not addressed by the Commission. |
| Forward-looking |  | | In biennial filings, the utilities use the two previous 12-month periods as test years and adjust for the costs that are reasonably expected to be incurred during the following two rate years. | Because future costs are not known and measurable, regulators risk overcompensating a utility based on its forecasted costs, which may be inflated. Further, a future test year reduces regulatory lag, which attenuates a utility’s cost control incentive. |
| Backward-looking (w/ earnings adjustments) | **+** | | The backward-looking analysis allows the Commission to identify over- or under-earnings to establish whether customers are due refunds.  Dominion earnings sharing mechanism: During biennial review, for the test period, if the Commission finds Dominion earned above its fair combined rate of return for generation and distribution services, 85% of earnings are credited to customers and Dominion retains 25%. If the utility earned more than 150 basis points above fair return, all earnings above 150 basis points are returned to customers.  APCo earnings sharing mechanism: During biennial review, for the test period, if the Commission finds APCo earned more than 100 basis points above fair combined rate of return for generation and distribution services, customers receive 100% of the earnings above 100 basis points. | It’s important to note that the current two-year rate period dampens any cost control signal from the earnings sharing mechanism for both APCo and Dominion because the utility would only get extra earnings delivered from possible cost efficiencies for one year until rates are reset in the next biennial rate review.  The existence of a 100 basis-point deadband offers some cost-containment incentives to APCo as it is allowed to retain all earnings up to 100 basis points above its allowed return. The earnings test could increase cost containment incentives for APCo if the utility was allowed to retain some portion of the excess earnings over 100 basis points (e.g., 25%). However, the short duration between rate reviews may dampen the cost-containment incentives of the earnings test. |
| **ROE Determinations** |  | **0** | | The 2007 Re-regulation Act imposed heavy restrictions on the Commission’s ability to set APCo and Dominion’s authorized return on equity (ROE). Under this law, the SCC could not set an electric utility’s ROE below a “floor” based on the average ROE of a statutorily proscribed group of so-called “peer” companies. This artificial floor resulted in SCC-recommended ROE rates that were higher than what they would have been absent the restrictions.[[5]](#footnote-5) The 2023 reforms that restored many fundamental authorities to the SCC statutorily established Dominion’s ROE for the 2023 rate case; however, moving forward, the SCC will have no restrictions on setting utilities’ ROE.  The consequence of the long-time restriction over ROE setting seems to be inflated profits that have contributed to increased costs for the last fifteen years. | When a utility’s ROE is higher than its cost of equity (i.e., cost of borrowing), it can negatively impact affordability and cost efficiency. This is because when a utility’s ROE is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. In addition to providing a utility with an incentive to increase its rate base, which ultimately increases rates, it also disincentivizes the utility from considering potential lower-cost investments such as non-wires alternatives, energy efficiency, and demand response.  It is also important that the ROE determination include an examination of the use of riders (see below) and PIMs. Regulators should account for the earnings potential (or potential penalties) associated with PIMs when setting the ROE. For example, if the utility is subject to reward-only PIMs, then its ROE should be set at the lower end of the range of reasonableness to account for the potential additional earnings from PIMs. |
| **Rate Adjustment Clauses (i.e., trackers)** | RACs overall (general assessment of the use of RACs) | **-** | | RACs benefit the utility by allowing it to recover costs more quickly but disincentivize cost containment incentives and undermine affordability.  Cost trackers erode a utility's incentive to control costs because the utility is allowed to reconcile revenues to actual costs each year. There is therefore no incentive for the utility to control its costs or seek cost efficiencies. | The 2007 Re-regulation Act created a cost recovery mechanism called rate adjustment clauses (RACs), mostly known in other jurisdictions as riders. RACs allow utilities to recover certain costs through special issue charges outside of base rates. RACs provide substantial benefits for utilities, since RAC-eligible costs are guaranteed to be recovered by the utility, along with its fair rate of return. This construct is a substantial departure from traditional rate-making principles whereby regulation is not supposed to guarantee utility profitability, but it is supposed to ensure utilities have the *opportunity t*o recover costs and be profitable **if business decisions are reasonable**.  Although rider treatment for specific strategic programs and investments is a common practice for utilities in multiple jurisdictions, in Virginia, riders are transitioning to be the primary cost recovery mechanism, slowly replacing the base rate. Today, more than 50% of utility costs are recovered through riders, and this trend is set to continue. Dominion Energy estimated that “75% of the $35.5 billion of capex would be eligible to be recovered through RACs. As a result, by 2029, DEI [Dominion Energy, Inc.] projected that a total of 62% of DEV's $63.4 billion net rate base would be eligible to be recovered through RACs.” [[6]](#footnote-6)  Having a large number of RACs essentially shifts Virginia’s regulatory framework toward a formula rate plan (FRP). Similar to RACs, FRPs allow for a utility to true-up revenues to actual costs. Other jurisdictions have found that FRPs create negative outcomes for customers. In Arkansas, Entergy had an FRP with annual rate true-ups capped at 4% each year. The Arkansas Commission staff found that the FRP incentivized spending and the outcome of a 4% increase each year (over the prior year). Staff further concluded that the unstated implication of the FRP was that the risk of an earnings review was effectively eliminated. With revenues guaranteed to be trued-up to the costs incurred, there was no clear incentive to contain costs between the annual 4% increases.[[7]](#footnote-7) The Maryland Public Service Commission also noted that problems with formula rate plans include a “tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs.”[[8]](#footnote-8) Allowing Virginia utilities to use riders for a growing number of cost categories has in practice the same logic as the Arkansas formula rate plan: annual true-ups of utility costs that guarantee profitability and offer little incentives for cost control.  Under traditional base rates, utility shareholders and management face normal business risks, such as lower electricity sales or poor management; in contrast, RACs shift business risk to ratepayers. Because most RACs are trued-up every year, this instrument eliminates two factors that historically have worked as market-like cost-control mechanisms: 1) the regulatory lag, which is the period of time between incurring costs and rate increases that reflect those higher costs, and 2) the risk of profit under-recovery between rate cases. These two factors function similarly to the risk a firm experiences in competitive markets. The competitive firm must manage costs efficiently to ensure competitive prices. Otherwise, customers could move to another, more efficient firm with lower prices, which will in turn decrease sales and hurt the firm’s profits. In the case of regulated utility monopolies, a similar incentive exists when, if the firm is not managed efficiently and costs rise too quickly, the utility bears the risk of decreased profits between rate cases. With the yearly true-ups RACs provide, this risk resulting from inefficient management disappears for the regulated utility shareholders and is instead shifted to customers who have to guarantee utility profitability.  Without market-like incentives to control costs, the only financial risk and incentive for prudent management comes from the State Corporation Commission's scrutiny of business decisions and its ability to disallow imprudent past expenses or deny approval of unnecessary future projects. Although this is a powerful tool, without market-like financial risk, it can be insufficient as a cost containment incentive. Historically, the Commission has not disallowed substantial costs. Furthermore, on multiple occasions, utilities have influenced the legislative process to declare project costs previously rejected by the Commission as “reasonable and prudent.” The capacity to influence legislative outcomes further reduces the risk of cost disallowance, weakening cost containment incentives.  Finally, because the RAC construct substantially reduces the risks associated with capital-intensive projects, RACs exacerbate the Averch-Johnson effect. This economic theory explains how regulated firms may overinvest in capital when a firm's allowed return on capital (set by regulators) is higher than its true cost of capital. The firm maximizes profits by overinvesting in capital-intensive assets rather than choosing the most efficient mix of other resources. This results in inefficiency, higher costs for consumers, and a potential misallocation of resources.  This is why best practices have historically indicated that riders should be used only for limited costs outside of a utility’s management control, and why recent practice in other jurisdictions limits the use of riders to strategic programs that the utility compensation system does not traditionally incentivize, such as energy efficiency and demand response.  Two relevant advantages of RACs include that riders increase transparency, making it easier to track individual project costs, and the true-up mechanism ensures that customers are protected from any over-recovery of specific expenses. However, these two advantages could be incorporated into a more balanced rate-making design. These benefits do not outweigh the drawbacks of overreliance on riders as cost-recovery mechanisms.  Recognizing the flawed incentives associated with riders' extensive usage is important to advance solutions that would protect ratepayers from inefficient utility operations. Any future regulatory design should limit riders' usage and frequent cost true-ups to a narrow range of strategic investments that the utility does not have an intrinsic financial incentive to undertake. Energy efficiency and demand response are classic examples of resources that, although beneficial for customers and the system overall, have been neglected, since a decrease in sales can harm a utility’s profits. RAC treatment for these types of expenses could be part of an incentive package to increase their deployment. |
| Fuel Cost Recovery | **-** | | The current recovery of fuel costs allows for recovery on a dollar-for-dollar basis with no return available to the utility. Fuel cost recovery adjustments are common. These do not provide any cost containment incentives since costs are automatically trued-up and passed on to customers |  |
| Purchased power | **0** | | Does not have a clear impact on the outcome. |  |
| Demand response program costs | **0** | |  |  |
| RPS compliance costs | **0** | |  |  |
| Broadband capacity extension |  | |  |  |
| Low-income programs (lost revenue recovery) | **0** | |  |  |
| Capital projects (e.g., combined cycle gas projects, offshore wind, solar, distribution system undergrounding, distribution grid transformation, nuclear life extension, etc.) | **-** | | (Same as RACs above) Using riders for a multitude of capital projects is not as common in other jurisdictions as in Virginia. | (Same as RACs above) |
| **Other trackers** (user choice to select additional trackers used in Virginia rate making for attention) |  |  | |  |  |
|  |  | |  |  |
| **Transmission cost recovery (FERC formula rates)** |  |  | |  |  |
| **Performance adjustments and measurement** | ROE adjustment mechanisms |  | |  |  |
| Energy efficiency savings target (ROE adder applied to DSM operating expenses) | **+** | | Va. Code § 56-585.1 provides that a utility that meets its energy efficiency savings targets shall earn a return on the operating costs associated with its energy efficiency programs. Further, if the utility exceeds its savings targets, the utility can earn an additional 20 basis points for each additional 0.1% in annual savings beyond the target.  Substantial evidence and applications show that energy efficiency gains can prevent the need for costly infrastructure projects. To the extent that energy efficiency programs are cost-effective, incentivizing the expansion of this resource would benefit affordability | In recent proceedings, Dominion Energy has forecasted that it will not comply with the energy efficiency targets established in 2020, and both APCo and Dominion proposed unreasonably low energy efficiency targets for the 2026-2028 period, which pushed down the range the Commission used to select new targets. The lack of compliance with existing targets and push for unambitious future ones, while both utilities pursue capital-intensive projects with higher levels of complexity, higher customer risk, and in some cases higher environmental impacts, casts doubt 1) on how serious investor-owned utilities are about the Commonwealth's policy commitment to energy efficiency as a low-cost resource and 2) on these utilities’ commitment to solutions that would directly promote customer affordability, especially during the periods with the highest energy consumption.  The incentive framework put in place in 2020 was intended to equalize energy efficiency as a source of profit for utilities; however, the profit potential of new capital-intensive solutions still far outweighs the profit potential of energy efficiency and demand response programs. The current incentive framework lacks an effective and independent enforceability mechanism. Additionally, energy efficiency assumptions in utility resource planning have been flawed and insufficient. Thus, customers are still left without any assurance that, despite the strong financial incentive to prioritize capital-intensive projects, utilities will prioritize to the maximum extent possible low-cost energy efficiency and demand response solutions.  If utilities are anticipating general cost increases, energy efficiency should be the cornerstone of the utilities’ resource mix, since this will directly help customers generate savings during the months with the highest consumption. The importance of this resource for customer affordability, resource adequacy, and reliability merits considering the use of existing Commission tools to guarantee compliance with targets, such as by lowering a utility's authorized ROE range. Other tools could include: 1) penalties for under-achievement and 2) requesting a report of performance metrics and improvement targets for customer awareness of and enrollment in energy efficiency programs.   Finally, while the ability to earn a return on energy efficiency costs helps to offset the utility’s throughput incentive and capital bias, creating an incentive for DSM programs that is not based on the amount of money spent may help to avoid the creation of an incentive for the utilities to inflate their DSM budgets, which will unnecessarily increase costs to customers. |
| Performance mechanisms (e.g., metrics, scorecards, PIMS), including Case No. PUR-2023-00210 (Separate SCC PBR Case) | + | | This tool’s impacts on affordability depend on the PIM design and the overall cost savings achieved by the program the PIM intends to incentivize.  PIMs can help align a utility’s financial incentives with the public interest. However, PIMs should be designed in concert with cost recovery mechanisms. For example, if the utility can recover the costs of meeting a PIM target through a tracker, then it has every incentive to spend as much as is required to meet the PIM target, even if the costs outweigh the benefits. | PIMs should be implemented in Virginia alongside incentives to control the costs associated with meeting the PIM targets. In addition, the total value of potential PIM rewards plus the utility’s base ROE should not be excessive, or the utility will have a stronger incentive to expand its rate base. |
| **Other ratemaking and regulatory features** | IRPs | **0** | | In theory, Integrated Resource Plans should be a useful instrument to identify least-cost pathways to compliance with existing laws and regulations. However, although a critical tool for stakeholders to understand utilities’ overall investment plans, IRP proceedings are not currently conducive to finding, studying, and exploring least cost pathways. Rather, they are a forceful litigation process where utilities’ main goal is to justify and defend their pre-established investment decisions.   In Virginia, the IRP lacks enforceability, meaning that these plans are not binding, and the utility is not required to adopt any specific plan. Furthermore, since 2023, only Dominion has been required to present a planning document, while APCo has been excluded from this obligation. Although a lot of the same planning work is filed by APCo in its renewable portfolio standard (RPS) proceedings, these RPS filings are not suited to analyzing alternative options in detail or to requesting alternative modeling assumptions.  Since 2023, Virginia law has required an IRP stakeholder process to facilitate stakeholders’ participation in and understanding of the planning process. Although this has generated positive progress for Dominion’s planning process, the final result of the 2024 IRP was not much different from the deficient document filed in the previous year by the utility. | The IRP is the only place where a utility’s resource plan can be holistically evaluated; however, changes or modifications to the planning document do not have to translate into specific resource acquisition decisions. To Clean Virginia’s knowledge, there is no other proceeding where the Commission and stakeholders can actually compare investment portfolios and ensure that the path forward is the most cost efficient and affordable solution possible. However, the lack of connection between planning and resource acquisition reduces the usefulness and undermines the goals of IRP proceedings.  The end result is that the IRP is currently not a proceeding that is conducive to ensuring future utility investment plans are the least-cost alternative available.  Although reforms to the planning and resource acquisition frameworks are not classic PBR concepts, these aspects are crucial to improve the performance areas under evaluation. Cost-efficient utility investments and affordability are intrinsically connected to effective planning. Furthermore, with the extensive use of riders weakening cost containment incentives, improving the IRP process to ensure plans reflect least-cost solutions that comply with the existing laws and regulations is of utter importance. |
| Certificates of Public Need and Necessity (CPCN) | **0** | | A CPCN is a permit granted to a utility that authorizes it to provide service to a new geographic area, enter into a new franchise agreement, and construct and operate a new facility or an extension of a facility that is outside the "ordinary course of business." The extend to which a CPCN favors or disfavors affordability depends on whether or not the approved project is the least-cost and lest-harmful option available to meet grid demand. And the extend to which utilizes are accountable for thoroughly proving this. | For investor-owned utilities, a CPCN functions as a pre-approval of investments. Early research on this issue by the National Regulatory Research Institute argued that investment pre-approval “might bolster investor confidence because preapproval might lessen the probability that plants would be excluded from the rate base as excess capacity (or for other reasons) and  that the expenses of the cancelled plant would not be amortized.”[[9]](#footnote-9)  A critical factor to consider as part of a CPCN proceeding is the question of need. Utilities generally rely on load forecasting and modeling produced during integrated resource planning proceedings (IRPs) to establish need. IRPs in Virginia are critical planning documents that, although they do not approve specific projects, serve as the basis to show why specific investments are needed. IRPs are supposed to outline a least-cost overall path to comply with existing law that considers and weighs all alternative resources. However, there is no clear connection in Virginia between the IRP results and CPCNs for specific projects. For example, a utility could move forward with a CPCN request even though the general planning document has not been approved by the Commission. Thus, utility CPCN petitions do not necessarily follow a Commission-approved and stakeholder-vetted least-cost resource acquisition plan.  This lack of connection between careful consideration of least-cost alternative options and resource acquisition harms affordability and undermines certainty about the pertinence and need of the utility's proposed investments.  Although each CPCN proceeding considers the need for specific resources, the process lacks a holistic analysis of system alternatives. |
| Rate design (including universal service fee) |  | |  |  |
| Pilot programs |  | |  |  |
|  | Limits to third-party-owned generation | **-** | | Current statute limits the amount of third-party owned generation allowed to comply with Virginia’s clean energy goals at 35%. This limit disincentivizes affordability since it prevents low-cost projects from being part of a utility’s resource mix. | Ratepayers should be allowed to benefit from available low-cost, qualified third-party-owned projects to the maximum extent possible. The current 35% limit is a barrier to this cost-saving opportunity. For example, during the 2022 renewable portfolio standard proceeding for Dominion Energy, the Office of the Attorney General argued that qualified bids from third-party owned projects were 2 to 3 times less expensive than utility-owned projects, and that there was not sufficient justification to reject these less expensive projects. The only significant barrier for the utility to select these projects was the 35% limit on third-party owned projects that exists in the code. |

Overall Assessment

|  |  |  |
| --- | --- | --- |
| **Overall, does the existing regulatory framework support achievement of the identified outcome?** | | **Discussion** |
| **+ (YES)** incents achievement |  |  |
| **0 (NO IMPACT)** |  |  |
| **- (NO)** disincentivizes achievement | **-** | Overall, the current regulatory framework offers weak financial incentives for cost containment, cost-efficient utility investments, and affordability. Although the extensive use of RACs and frequent biennial reviews may appear to increase accountability, in reality they shield utilities from market-like incentives to keep prices low and disproportionately shift business risk from utility shareholders to customers. SCC reviews, although extremely important, are not enough to replicate market-like incentives for efficient utility management. The Commission does not usually disallow substantial costs, even when evidence is presented by intervenors, and frequent participation in cases is prohibitively expensive for all stakeholders other than the utility. Furthermore, the current connection between least-cost planning and resource acquisition is weak, and the current planning process is not conducive to finding the most cost-effective system solutions. |

1. SCC Report on the implementation of the Virginia Electric Utility Regulation. November 2024. [↑](#footnote-ref-1)
2. SCC Report on the implementation of the Virginia Electric Utility Regulation. November 2024. [↑](#footnote-ref-2)
3. Dominion Energy 2024 IRP [↑](#footnote-ref-3)
4. Mark Lowry et al., “State Performance‐Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities”, Lawrence Berkeley National Laboratory, July 2017. [↑](#footnote-ref-4)
5. Investor-owned electric utility regulation in Virginia. Findings & Recommendations of the Electric Utility Regulatory Work Group (2001). [↑](#footnote-ref-5)
6. SCC Report on the implementation of the Virginia Electric Utility Regulation. November 2024 [↑](#footnote-ref-6)
7. AR PSC Staff, Initial Brief Pursuant to Order No. 18, Docket 16‐036‐FR, January 1, 2019. [↑](#footnote-ref-7)
8. Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53. [↑](#footnote-ref-8)
9. Profozich Russell, Robert Burns, Patrick J Hess, and Kevin Kelly. n.d. “Commission Preapproval of Utility Investments” The National Regulatory Research Institute. https://www.canr.msu.edu/ipu/uploads/migration/2016/12/Profozich-Burns-Hess-Commission-Preapproval-81-6-Dec-81.pdf. [↑](#footnote-ref-9)