GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

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Public Advocacy Division
Public Integrity Section

ELECTRONIC FILING

November 1, 2019

Ms. Brinda Westbrook-Sedgwick
Public Service Commission
Of the District of Columbia Secretary
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: Formal Case No. 1156 – In the Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia

Dear Ms. Westbrook-Sedgwick:

Enclosed is the District of Columbia Government's Comments on Technical Conference III in the above-captioned matter. If you have any questions regarding this filing, please do not hesitate to contact the undersigned.

Respectfully submitted,

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Attorney General

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

THE APPLICATION OF	**)**	
POTOMAC ELECTRIC POWER COMPANY	**)**	
FOR AUTHORITY TO IMPLEMENT A	**)**	**FORMAL CASE 1156**
MUL TIYEAR RA TE PLAN FOR ELECTRIC	**)**	
DISTRIBUTION SERVICE IN THE	**)**	
DISTRICT OF COLUMBIA	**)**	

District of Columbia Government's Comments on Technical Conference III – Framework for Evaluating Alternative Ratemaking Proposals

I. INTRODUCTION

In May 2019, the Potomac Electric Power Company (Pepco) filed a rate case application under two different ratemaking methodologies: a multi-year rate plan (MRP) with performance incentive mechanisms (PIMs) and a traditional cost-of-service plan. MRPs represent a fundamental change from cost of service regulation and offer the promise of increased benefits for both ratepayers and the utility. However, MRPs also present substantial peril if not designed well. The plans that are put forth are generally designed by utilities, which operate under a strong profit motive, and can therefore be expected to have a bias that favors the utilities. It is the earnest responsibility of the Public Service Commission of the District of Columbia (Commission) and stakeholders to carefully dissect MRP and PIM proposals in order to examine the incentives they provide (including perverse incentives), as well as the risks they pose, and to ultimately determine whether the plan will benefit ratepayers and the District of Columbia as a whole.

In Order No. 20204, the Commission decided that it would hold a Technical Conference on Alternative Ratemaking proposals and convene panels of experts to inform the Commission and its staff on the topic. On October 17 & 18, 2019, the Technical Conference took place at the Commission's hearing room. At the Technical Conference, Melissa Whited of Synapse Energy Economics presented on MRP and PIM issues on behalf of the District of Columbia Government (DCG). Additional parties presented panelists including:

- Maryanne Hatch of FTI Consulting on behalf of the Office of People's Counsel of the District of Columbia (OPC);
- Pearl Donohoo-Vallett of the Brattle Group on behalf of Pepco;
- Bruce Oliver and Timothy Oliver of Revilo Hill Associates, Inc., on behalf of the Apartment and Office Building Association of Metropolitan Washington D.C. (AOBA); and

- Scott Hempling on behalf of the Baltimore-Washington Construction and Public Employees Laborer's District Council (BWLDC).

DCG agrees with many of the comments made in the presentations by OPC and AOBA. In particular, DCG agrees with OPC in the importance of having clearly defined goals before enacting any alternative rate design. DCG further agrees with OPC that any alternative ratemaking proposal must not shift risk and burdens onto ratepayers as compared to the status quo. DCG also agrees with AOBA's observation that the experience in other jurisdictions with alternative ratemaking is mixed at best. Importantly, DCG agrees with AOBA that periodic reconciliations during an MRP erode a utilities' incentive to control costs. These issues, as well as issues raised by Pepco will be discussed in more detail below. Finally, DCG is glad BWLDC has raised worker treatment issues. The Union is right: mistreated workers lead to service errors and unnecessary costs. The Commission has the jurisdiction and duty to address such issues in its regulation of utilities.

The Order No. 20204 further stated that the Commission will issue a Policy Order on the alternative forms of regulation framework, following the Technical Conference and the comments submitted regarding the issues discussed at the Technical Conference. DCG, through the Department of Energy and Environment (DOEE), commends the Commission for taking the necessary time to carefully develop a framework for evaluating whether an alternative ratemaking proposal is in the public interest. The Commission has the authority to adopt alternative forms of regulation which:

a) protect consumers;

b) ensure the quality, availability, and reliability of regulated electric services;

c) are in the interest of the public, including shareholders of the electric company.[1]

In addition, under the CleanEnergy DC Omnibus Amendment Act of 2018, the Commission must consider not only the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, but also the effects on global climate change and the District's public climate commitments.

In Order No. 18846, the Commission noted that in considering any alternative mechanism, the Commission's focus "will include a review of the benefits that accrue to customers as opposed to solely focusing on the utility."[2]

DCG offers these comments pursuant to Order No. 20204 to aid the Commission's development of a Policy Order on a Framework for Evaluating Alternative Ratemaking Proposals, and, ultimately, in the review of specific alternative rate plans presented before the

[1] D.C. Code § 34-1504 (d) (2001). All rates must also be "just and reasonable" per D.C. D.C. Code § 34-911.

[2] Formal Case No. 1139, ¶594 (*rel.* July 25, 2017).

Commission. These comments do not replicate every response to the questions asked in the Amended Notice of Technical Conference, which was provided orally during the Technical Conference, but instead they prioritize and elaborate on those questions and issues that DCG thinks are most important.

II. ALTERNATIVE FORMS OF REGULATION

A. Multi-year Rate Plan Objectives

DCG opens its comments with a discussion of the key elements of MRPs, since there is often confusion regarding the definition and necessary components, particularly where it concerns the differences between MRPs and formula rate plans.

The Commission should reject multi-year rate plans which are MRPs in name only, but which function like formula rate plans. Formula rate plans are not in the public interest, as they do not provide utilities with strong incentives to contain costs and they shift risks to ratepayers. Because of the lack of incentive to contain costs, formula rate plans require regulators and stakeholders to expend much more effort reviewing the utility's investments and costs, essentially transferring risk and responsibility from utility management to ratepayers. This challenge is compounded by the fact that, regardless of how much information is provided to regulators, there will always be information asymmetry because the utility knows its system and the amount of effort management puts forward better than the regulator.

In contrast, if designed well, MRPs can provide benefits to customers and help achieve public policy goals. Stand-alone PIMs, layered on top of cost of service regulation, can also help to achieve policy goals without requiring a wholesale adjustment to the regulatory framework.

MRPs have been used for many decades in a variety of industries. Often MRPs are referred to as "price cap regulation" or "revenue cap regulation." These approaches have also been referred to as "hands-off regulation" because the utility's costs are not closely examined during the duration of the plan. Instead, the utility's revenues are de-linked from its actual costs in combination with a rate case moratorium (typically lasting from three to five years).

Jurisdictions typically implement MRPs to achieve some or all of the following goals:

- Provide the utility with cost containment incentives.
- Encourage innovation by allowing the utility to manage business decisions with greater flexibility, rather than the regulator micro-managing the utility's investments.
- Reduce regulatory costs and burdens by lengthening the time between rate cases.

- Provide utilities with greater regulatory guidance and assurance regarding investments in new and innovative technologies to better align utility investments with energy policy goals.

B. Core MRP Design Elements

The above goals are accomplished through four key design elements:

1) **Rate Case Moratorium:** A "stay-out" provision limits the ability for rates to be reset during the plan.
2) **Revenue Cap:** Revenues for each year of the plan are capped at certain pre-determined levels.
3) **Incentive to Improve Efficiency:** Utilities are incentivized to reduce costs during the plan by retaining some or all of the savings from efficiency gains, while ratepayers are protected from poor utility performance during the rate plan by being insulated from some or all of any increase in costs above the revenue cap.
4) **Attrition Relief Mechanism (ARM):** The initial year revenues may be escalated based on an index or cost forecast determined at the outset of the rate plan, or they can be frozen until the next rate case. Cost trackers may be added to the ARM for certain costs, particularly "exogenous" costs over which the utility has no control.

Each of these design elements is important for different reasons.

The rate case moratorium typically lasts 3 to 5 years, and ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge. This shifts the risk associated with poor utility cost management to utility shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives. It also helps relieve the regulatory burden associated with frequent rate cases. Without a rate case moratorium, the utility has little incentive to contain costs, because it can simply file for a rate increase if costs exceed revenues.

The revenue cap establishes the revenue a utility can recover each year, regardless of whether the utility's costs are greater than or less than the capped amount. This encourages the utility to manage its costs within the cap. Historically, MRPs often used price caps as opposed to revenue caps. However, modern MRPs generally cap allowed revenues, rather than prices, in order to reduce the utility's throughput incentive and encourage the utility to focus on cost reductions rather than increasing revenues. The revenue cap is generally combined with some form of decoupling mechanism that ensures that the utility recovers its allowed revenues, and no more or less.

An incentive to improve efficiency is provided by harnessing the utility's profit motive. By allowing the utility to retain some or all of the savings that it achieves through cost reductions during the duration of the rate plan, the utility is more likely to creatively and rigorously pursue cost reductions. However, as discussed in section VII, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

The ARM is an optional component but is often necessary in order to provide utilities with adequate revenue to enable them to agree to the MRP's stay-out provision. Without an ARM, the MRP is effectively a revenue freeze for a set amount of time. The design of the ARM is critical, as this is where information asymmetry between the regulator and the utility is greatest. An ARM may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. Importantly, the formula does not track the utility's *specific* costs. If the ARM were designed with a reconciliation mechanism to reflect the utility's actual costs, then there would be no incentive for the utility to reduce its costs.

C. Differences between MRPs and Formula Rate Plans

Both MRPs and formula rate plans (FRPs) feature formulas, thereby creating some confusion regarding the differences between the two approaches. The primary distinction is that formula rate plans formulaically ensure that revenues track costs, often measured as deviations in return on equity (ROE) from the utility's target ROE. If a utility's earned return is above its ROE target, it will be required to reduce its rates. Likewise, if a utility's earned return is below its target return it will be allowed to increase its rates.[3] Importantly, in contrast, MRPs do not adjust revenues to equal costs during the plan.[4]

A report by Edison Electric Institute describes an FRP as "essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service."[5] The report explains how this works as follows:

> Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated…. The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target.[6]

[3] Rate increases may be subject to some kind of review and approval process first.

[4] With the possible exception of a limited set of cost trackers or reconciliations for specific types of costs.

[5] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 47.

[6] *Ibid*.

In other words, formula rate plans true up revenues to costs once the ROE deviates from the allowed ROE by a certain amount. These true-ups are generally accompanied by some form of commission review and approval, but these reviews are more streamlined than those that occur in a general rate case.

Utility commissions have been reluctant to adopt FRPs due to the problematic incentives they provide and recognition that these plans shift risk onto ratepayers. For example, the Maryland Public Service Commission noted that problems with FRPs 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."[7]

These concerns have been borne out by experience in jurisdictions where FRPs have been implemented. Additional information is provided in the Appendix regarding jurisdiction's experiences with FRPs.

In contrast, MRPs in theory provide strong efficiency incentives precisely by *avoiding* cost true-ups. As noted in a Brattle Group report filed by the Joint Utilities in Maryland, "Multi-year rate plans typically have reconciliations **more limited in scope** and typically focused on capital expenditures, **to the extent that reconciliations are included at all** [emphasis added]."[8]

In another report, the Brattle Group wrote "During the course of an MRP, rates are either frozen or adjusted based on a prescribed rate adjustment mechanism; they do not depend on changes in a utility's costs (either historic or forecasted)…. During the term of the MRP, changes in recorded costs do not influence changes in rates, and utilities realize all or part of the financial benefits resulting from successful efforts to control costs. However, this benefit does not last forever; these benefits are transferred (in whole or part) to ratepayers when rates are rebased [at the conclusion of the MRP]."

As explained in the Edison Electric Institute's survey of alternative regulation mechanisms, "[t]he rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth [emphasis added]."[9]

Because revenues do not increase in lock step with costs, the utility has an incentive to reduce costs to increase its profits for the duration of the rate plan. At the end of the MRP term, these cost reductions can then be passed on to ratepayers when rates are reset in a rate case.

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[7] Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53.

[8] The Brattle Group, Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates, Joint Utilities' Joint Initial Comments, Maryland PC51, March 2019.

[9] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

This critical difference between FRPs and MRPs leads DCG to believe that FRPs or MRPs that essentially resemble FRPs are not in the public interest.

III. Benefits and Risks of MRPs and PIMs

Panel 1, Q2. What are the benefits of any alternative forms of regulation, including performance-based ratemaking ("PBR") or MRP/PIM, relative to its costs/risks?

A. MRPs

As DCG noted in our presentation at the technical conference, MRPs present both promise of benefits and perils if designed poorly.

A recent report published by Lawrence Berkeley National Laboratories outlined several potential benefits of MRPs, along with several potential disadvantages, which we summarize below.[10]

Potential benefits of MRPs

1. Stronger incentives for the utility to reduce its costs.
2. When coupled with PIMs, stronger incentives for the utility to improve performance across a wide variety of initiatives and achieve policy goals.
3. Reduced regulatory cost due to fewer rate cases.
4. More opportunity for the utility to profit from improved performance.

Potential Risks of MRPs

If not well-designed, however, MRPs can pose significant risks, including:

1. Information and resource asymmetry, particularly when regulators and other stakeholders lack the expertise and funding needed to effectively consider the implications of MRPs and to address design issues. This asymmetry can result in higher costs, without commensurate benefits, to ratepayers.
2. A utility's revenue may exceed its costs for extended periods of time. Although higher utility profits in exchange for improved performance is

[10] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 2. Available at https://escholarship.org/uc/item/4r13j347. (Attached hereto as Exhibit A).

part of MRP design, there is a risk that the utility may be overearning as a result of other factors.

3. Revenue adjustments may not provide adequate revenue to accommodate external factors, such as a major storm or change in regulatory requirements, or to provide for new and unusual investments. This may lead to chronic under-earning, or to the utility avoiding new and unusual investments.

4. Cost-cutting incentives of MRPs can lead to service degradation in other areas if service quality standards are not in place or are not rigorously enforced.

However, the above concerns can be largely mitigated through careful MRP design.

Tools to Mitigate MRP Risks

DCG submits that an MRP proposal should be approved only if it contains robust mechanisms to mitigate the risks. Such mechanisms, at a minimum, are as follows:

- Information and resource asymmetry should be mitigated by
  - Beginning with known and measurable costs (i.e., a historical test year)
  - Relying on an external index, rather than the utility's own cost forecast, to set the allowed revenue trajectory
  - Allowing adequate time for intervenors to fully examine the utility's costs and proposals
  - Retaining qualified experts and increasing the regulator's staffing levels
- Requiring earnings sharing above a certain threshold to ensure that the utility's earnings do not grow excessive. For example, the utility may be allowed to earn 200 basis points above its allowed ROE, but beyond that it must share some of the extra earnings with customers. However, earnings sharing mechanisms weaken utility performance incentives, particularly if the sharing must commence soon after the target ROE is achieved. Therefore, DCG recommends that earnings sharing begin no sooner than 50 basis points above the target ROE, and ideally at 100 basis points.
- To address the concern that the MRP may not provide adequate cost recovery, DCG recommends that certain costs be pulled out of the MRP and treated separately. In order to avoid reducing the utility's cost containment incentives, special treatment should be limited to a small subset of costs. DCG

recommends that the types of costs subject to tracker or reconciliation treatment be limited to the following:

- Large, unusual investments that are necessary to achieve public policy goals. These costs can be addressed outside of an MRP's standard revenue requirement through a cost tracker or other reconciliation mechanism. A capital cost tracker is often generically referred to as a "K-factor."
    - In Massachusetts, a factor was established to account for certain "foundational" grid modernization investments.
    - In Alberta, the utility's multi-year rate plan provides "top-up" funding for capital programs that grow faster than the index through a K-factor. To qualify for the K-factor, a program must meet three criteria: (1) it must be outside the course of ordinary operations, (2) it must replace an asset or be required by a third party, and (3) it must have a material effect on finances.[11]
- Recurring costs that are volatile and outside of utility control. For example, in New York these costs include taxes, pensions, environmental remediation costs, and market supply charges. The costs can be fully or partially reconciled during an MRP. Often these costs are referred to as "Y-Factor" costs. Criteria to qualify for this treatment should include:
    - The costs must be attributable to events outside management's control.
    - The costs must be material.
    - The costs must be prudently incurred.
    - All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.
- One-time exceptional costs that have a material effect on the utility's costs, are beyond the control of utility management, and which were incurred reasonably (such as extraordinary storm response costs). Factors to address one-time reconciliations are often referred to as "Z-factors."

Without these kinds of risk mitigation measures, DCG/DCG believes that an MRP could pose a greater risk to the ratepayers than the traditional cost of service regulation.

[11] William Zarakas et al., "Performance Based Regulation Plans Goals, Incentives and Alignment," December 6, 2017, Appendix B-7, https://www.michigan.gov/documents/mpsc/Brattle_Report_to_DTE_on_Performance_Based_Regulation_120617_613150_7.pdf.

B. PIMs

Potential benefits of PIMs

The report by Lawrence Berkeley National Laboratories also outlines the potential benefits and pitfalls associated with PIMs. [12] The potential benefits include:

- PIMs allow regulators and stakeholders to provide the utility with additional guidance regarding specific performance areas and desired outcomes.
- PIMs alert utility managers to special concerns of regulators and customers, helping to maintain good relationships among the parties to regulation.
- PIMs can provide new earnings opportunities in an era when traditional opportunities are diminishing for some utilities.
- PIMs are not an all-or-nothing proposition; they can be offered incrementally and gradually, thereby reducing customer risk.

Potential Risks of PIMs

PIMs can pose several risks:

- If there are significant financial incentives at stake, proceedings to design and approve PIMs can be complex, contentious and resource intensive.
- PIMs may focus excessively on areas that are easiest to measure, while overlooking other performance areas that also require improvement.
- If not well-designed, PIMs can lead to disproportionate rewards or unintended consequences.
- Chosen metrics are sometimes difficult to control. Targets can be unreasonable at the outset or ratcheted unfairly as performance improves.
- The costs of achieving the PIM target may outweigh the benefits to customers. This is especially true if PIMs are not coupled with cost containment incentives. If the utility can easily pass on the costs of performance to ratepayers, then it may incur excessive costs in order to achieve a favorable PIM outcome.

[12] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 3. Available at https://escholarship.org/uc/item/4r13j347.

Tools to Mitigate PIM Risks

DCG recommends that PIMs be developed carefully and implemented gradually in order to mitigate risks, with ample attention given to transparency of the mechanism, ensuring rewards and penalties are appropriate and no larger than necessary, and that the benefits of achieving the PIM outweigh the costs. Specifically, DCG recommends the following principles for PIMs shown in the table below, which are based on the recommendations in the attached report *Utility Performance Incentive Mechanisms: A Handbook for Regulators*:[13]

Regulatory Contexts	• Policy goals should be clearly articulated and guide PIM selection • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

[13] Melissa Whited, Tim Woolf, and Alice Napoleon, "Utility Performance Incentive Mechanisms: A Handbook for Regulators" (Synapse Energy Economics, March 9, 2015), at 57. Available at http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf. (Attached hereto as Exhibit B).

IV. NEED FOR ADDITIONAL RESOURCES

Panel 2, Q11. Do alternative forms of regulation change the role of the Commission and other stakeholders? If so, what if any additional resources will the Commission need?

Yes. DCG disagrees with Pepco's expert's Panel 2 presentation, which states that MRPs and PIMs "do not fundamentally change the role of the Commission and stakeholders," and that these forms of alternative regulation "are adjuncts to rather than a departure of cost of service regulation."[14] As discussed above, there can be significant risk associated with MRPs and PIMs relative to traditional cost of service regulation. It is imperative that the Commission ensure that it has adequate resources and staff to review the utilities' filings and ensure that they are in the best interest of ratepayers. MRPs based on cost forecasts could require a great amount of resources and staff for review, while MRPs based on an index are less resource intensive. For example, New York's Public Service Commission employs 545 staff to regulate five investor-owned utilities (an average of 109 staff per utility),[15] while Massachusetts' Department of Public Utilities employs 193 staff to regulate three investor-owned utilities (an average of 64 staff per utility).[16]

Regardless of the avenue that the Commission takes for MRPs, additional resources will be required to review any PIM proposals to ensure that they are reasonable. The Commission should also endeavor to ensure that stakeholders have adequate time to retain experts and review the utilities' filings.

V. FRAMEWORK FOR EVALUATING ALTERNATIVE FORMS OF REGULATION

Panel 1, Q4. What are the key decisions factors (metrics or criteria) to be used to evaluate and select an alternative form of regulation…?

Based on the potential benefits and risks described above, DCG recommends that the Commission evaluate an MRP proposal against the criteria contained in the following table.

[14] Donohoo-Vallett, Pearl and W. Zarakas, on behalf of Pepco. Panel 2: Implementation Experiences of Other States, October 18, 2019, at 15.

[15] Central Hudson Gas & Electric, Consolidated Edison, New York State Electric & Gas/Rochester Gas & Electric, National Grid, and Orange & Rockland.

[16] National Grid, Until, Eversource Energy.

Table 1. Evaluation Criteria for Multi-Year Rate Plans

Category	Key Criteria
Information and Resource Asymmetry	• Are the allowed revenues set based on an objective, external index, or are they based on the utility's own estimates? If the latter, information asymmetry will be high and the Commission will be at a disadvantage. DCG strongly recommends relying on an external index to set allowed utility revenues. • Is adequate time and staffing available for the Commission, the Office of People's Counsel, and intervenors to review the utility's proposal?
Administrative Burden	• Does the MRP actually reduce administrative burden after the rate plan is approved? • Is regulatory review in the intermediate years of the rate plan streamlined?
Costs	• Are costs lower than they otherwise would have been?
Risk	• Does the risk associated with managing the utility remain with utility managers? Or are risks shifted to ratepayers? o Who bears the risk of cost overruns? o Who bears the risk of forecast error? o Who bears the risk of stranded costs?
Core Performance Areas	• Is the utility maintaining an acceptable level of reliability and customer service?
Policy Goals	• Is the utility achieving policy goals (e.g., grid modernization, DER interconnection, EV adoption, microgrids, customer empowerment, resilience, etc.)

DCG also recommends that PIMs be evaluated against the criteria contained in the following table.

Table 2. Evaluation Criteria for PIMs

Category	Key Criteria
Objectives	• Are the PIMs based on clearly-defined policy objectives of the District? • Are the PIMs appropriately balanced across policy objectives, or are some objectives disproportionately emphasized?
Net Benefits to Customers	• Do the benefits of target attainment outweigh the costs of achieving the PIM target plus any incentive payment? • Is the utility rewarded only for performance that exceeds its expected (baseline) performance level? • Is a financial reward or penalty necessary to offset an existing disincentive or lack of incentive to perform in this area?
Risk and Transparency	• Are PIMs implemented gradually in order to reduce risk of improper PIM design or specification? • Are metrics and targets well-defined and measured transparently? • Are PIM targets reasonable and largely within the control of the utility? • Are financial incentives no larger than necessary, thereby avoiding undue risk and excessive contention? • Are steps taken to reduce the potential for gaming?

VI. SETTING THE ALLOWED REVENUE REQUIREMENT

Panel 2, Q3. Should an alternative form of regulation always require a proposal for base year (historical test year), a bridge year and one or more forecasted test years? What are the pros and cons for different forms and proposals?

DCG submits that the revenue requirement should be based on a historical test year (with necessary adjustments as currently allowed by the Commission), as these are the only costs that are truly known and measurable. The historical test year can then be escalated based on an external cost index to provide the allowed revenue for each year of the plan. For example, if the historical test year is 2018 but rates will not go into effect until 2020, the revenue requirement would be escalated to account for two years of inflation in order to derive rates for 2020.

VII. REVENUES ESCALATED BASED ON COST FORECASTS

Panel 1, Q11. If the alternative ratemaking is based on forecasted costs, what mechanisms and incentives should the Commission adopt that ensure effective review of forecast methodology and data inputs, ensure shifts in risk are appropriate and promote just and reasonable rates to end users?

Panel 2, Q4. What are the best practices for reporting requirements regarding forecasted vs. actual values, measures for reconciliation and timelines?

DCG will answer these questions together. With cost forecasts, information asymmetry is a serious concern, which has led many jurisdictions to opt for an index-based approach. DCG submits that there is no way of fully mitigating the information asymmetry associated with cost forecasts while simultaneously providing the utility with strong cost-containment incentives. Therefore, DCG does not recommend that the Commission allow the use of cost forecast in an MRP.

The National Regulatory Research Institute describes the issue of information asymmetry as follows:

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

Nonetheless, if the Commission allows the use of a forecast-based ARM, the Commission should employ strategies that can be used to mitigate the degree of information asymmetry, as discussed below.

1. If cost forecasts are used to set allowed revenues, they should be accompanied by a one-way (downward) reconciliation mechanism, as is done in Minnesota and New York. These reconciliations should be implemented on an annual basis. Although this reduces the incentive for the Company to implement cost containment measures, it protects customers from utility over-spend.

2. If an MRP is based on a forecast, or includes a forecast for specific items, then the utility should report:

[17] Costello, "Multiyear Rate Plans and the Public Interest," 35–36.

a) Changes in project implementation (i.e., which planned projects were not implemented, or are behind schedule)

b) Changes in project costs above a certain threshold (e.g., deviations of 10% or more)

3. Under an MRP with a cost forecast, short-cuts based on historical levels of spend may be used to estimate the appropriate level of new capital additions. These methods can provide greater assurance that cost forecasts are reasonable.

   a) Plant additions may be set for each plan year at the utility's average value in recent years.

   b) Plant additions may be set for each plan year at the value calculated in the test year of the most recent rate case.

   c) Operation and maintenance expenses can be forecasted using index-based formulas.[18]

4. A menu approach presents the utility with trade-offs between potential profits and levels of allowed revenues. The utility's choice reveals much about the utility's actual underlying costs. This approach is used in the United Kingdom. The menu provides the utility with a choice among various combinations of allowed revenues and earnings sharing mechanisms, such as:

   a) A plan with high revenues but for which it retains only a small portion of any cost savings, or

   b) A plan with low revenues but under which it can retain a higher portion of cost savings.

5. Independent benchmarking and engineering studies should be periodically used to determine the reasonableness of cost forecasts. However, DCG cautions that such endeavors are costly.

6. Performance incentive mechanisms for forecasting accuracy should be created in order to provide the utility with the incentive to forecast accurately.

That said, DCG emphasizes that these strategies will not fully protect the ratepayers and may still end up shifting the risks that should be borne by the utility onto ratepayers. Under an index-based MRP without cost reconciliations, no reporting of differences between forecasted vs. actual values is necessary.

[18] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.2, https://escholarship.org/uc/item/4r13j347.

Panel 1, Q14. Should alternative forms of regulation be designed to recover the cost of specific, clearly identified capital projects, and, as appropriate, Operations and Maintenance Costs? Should the Commission require public utilities to provide ongoing reports on the status of planned projects and, when a public utility changes its capital project plans, to propose appropriate changes to its cost recovery mechanisms?

DCG maintains that cost forecasts are rife with uncertainty as well as information asymmetry. The utilities may have an idea of the magnitude of expected costs in the future, but beyond a single year in advance, the utilities generally do not have information regarding the specific capital investments that they will be making (other than large investments that must be planned well in advance).

Instead of basing allowed revenues on cost forecasts, DCG strongly asserts that an index-based mechanism should be used for an MRP. Further, if the utility is allowed to retain some or all of the cost savings below the revenue cap, it will have more of an incentive to only make those capital investments that are truly necessary and will have the incentive to seek out lower-cost options (such as non-wires alternatives) where possible.[19]

VIII. TRUE-UP OR RECONCILIATION PROCESS

Panel 1, Q12. What parameters should be considered in the true-up or reconciliation process (annual, semi-annual, quarterly)? What is the best practice for such a process?

DCG notes that it is not clear what type of reconciliation is referred to in the question: reconciliation of revenues to costs, or reconciliation of actual revenues to allowed revenues. DCG addresses both in detail below. We emphasize that *cost* true-ups are inappropriate and are unlikely produce just and reasonable rates, but *revenue* true-ups (i.e., revenue decoupling mechanisms) may be reasonable if they are well-designed.

Cost True-Ups

Under traditional cost-of-service regulation, rates are set and are not trued up to actual costs until the following rate case. This regulatory lag provides an incentive for utilities to control costs between rate cases. Similarly, at the outset of an MRP, a set schedule of allowed revenues is set for each year of the plan. In general, revenues are not trued up to actual costs once the allowed revenues are set in order to provide incentives to control costs. Therefore, DCG maintains that revenues should not be trued-up to actual costs except in the following cases:

[19] This incentive is strongest in year 1 of an MRP and attenuates over time as the next rate case approaches. Longer-term MRPs provide a stronger cost containment incentive than shorter-term MRPs.

1. Large, unusual investments that are necessary to achieve public policy goals;
2. Recurring costs that are volatile and outside of utility control;
3. One-time exceptional costs that have a material effect on the utility's costs, are beyond the control of utility management, and which were incurred reasonably;
4. If the revenue trajectory is based on the utility's cost forecast, then a one-way (downward) reconciliation mechanism is appropriate.

Implementing true-ups beyond the above narrowly-defined cost categories would substantially reduce utility incentives to operate efficiently in the same manner as FRPs.

Revenue True-Ups

DCG does not oppose truing up actual revenues to allowed revenues, such as through a revenue decoupling mechanism. This removes the utility's incentive to increase sales in order to increase revenues and removes the effects of weather and energy efficiency.

Panel 2, Q6. Under alternative forms of regulation, what are the best practices for the true-up or reconciliation process that the Commission should consider?

DCG reiterates that cost true-ups are not recommended except for some narrowly-defined cost categories. Where cost reconciliations are adopted, the following principles should be followed:

1. Where cost forecasts are used, they should be accompanied by one-way, downward reconciliations. For example, in Massachusetts, a separate mechanism is provided outside of the MRP for grid modernization costs. The costs are capped, and all grid modernization-related capital and O&M expenditures below the cap are reconciled. In New York, revenues for new capital expenditures are based on cost forecasts and are subject to a one-way (downward) reconciliation mechanism.
2. For costs that are largely outside of the utility's control, DCG recommends that the Commission consider both full and partial reconciliations. If the costs are somewhat within the utility's control, a partial reconciliation (such as reconciling only 75% of cost deviations) provides the utility with greater incentive to manage these costs. This approach is used for some categories of cost in New York.

DCG notes that it agrees with some, but not all, of Pepco's characterization of reconciliations presented on slides 10 and 11 of Pepco's Panel 2 presentation. Specifically, DCG agrees that MRPs *may* include reconciliations, but emphasizes that these reconciliations are typically very limited in scope (e.g., to costs outside of the utility's control, or specific reliability project costs).

DCG highlights that where general capital investment reconciliations are allowed, DCG is aware of allowing only downward reconciliations, where under-spend is returned to customers and any overspend cannot be collected until the next rate case.

In addition, DCG disagrees with the term "reconciliations" applied to return on equity on Pepco's Panel 2 slides 10 and 11. DCG believes that Pepco's expert is referring to earnings sharing mechanisms in which earnings above a certain level are shared with ratepayers as a customer protection measure. DCG is not aware of any MRPs that otherwise "reconcile" a utility's ROE to its target ROE, as that type of reconciliation is limited to formula rate plans. Further, with the exception of a proposed bi-directional earnings sharing mechanism in Hawaii, DCG is not aware of any MRPs in the United States that provide for sharing of under-earnings with ratepayers.

Panel 2, Q7. Is it a best practice to require updated forecasts over the term of a MRP? If so, what specific updates are needed?

DCG maintains that cost forecasts should be avoided, except for specific, discrete categories of cost that require special treatment. Where cost forecasts are used, there is no need to update the cost forecasts since a one-way, downward-reconciliation mechanism is in place.

IX. Ensuring Ratepayers are Paying Only for Prudent and Efficient Costs

Panel 1, Q3. Under alternative ratemaking including MRP, how can the Commission assure ratepayers that they are paying only for prudent and efficient costs, and that the burden of proof remains with the public utility to show that a proposed rate change is just and reasonable?

Prudency: DCG submits that the prudence of specific utility investments should only be determined at the end of the MRP when the utility comes in for its next rate case. Assets should not be rolled into rate base until the prudence review at the next rate case. As in Rhode Island, cost overruns or underspends can be dealt with in regulatory assets/liability.

Efficiency: Cost efficiency is difficult to measure. While it is tempting to assume that adequate oversight and approval of utility investment plans will result in efficient investments, in actuality the regulator will never have as much knowledge of the utility's system as the utility itself. Therefore, DCG submits that cost efficiency should be assured by providing the utility with strong cost containment **incentives**. Under the current regulatory paradigm, regulatory lag serves to delay the utility's recovery of higher cost levels, which encourages the utility to manage its costs. Under and MRP, the efficiency incentive is provided by allowing the utility to retain a portion of any savings it achieves below the revenue cap.

Just and Reasonable Rates: It is extremely difficult to ensure that utility cost forecasts are just and reasonable, as utility regulators do not have the same information or resources as the utility. Allowed revenues that are based on historical costs, escalated for inflation, provide greater assurance that utility costs are just and reasonable, and that in turn rates are just and reasonable.

Panel 2, Q2. What are the best practices being implemented to assure prudence review is adequately conducted during the reconciliation process so that it is not overburdensome but achieves the purpose?

DCG reiterates that prudency should only be determined at the time of the next rate case. A prudency determination should not be made at the time of any reconciliations (if there are any).

X. IMPRUDENTLY INCURRED COSTS

Panel 1, Q13. Should public utilities seeking alternative forms of regulation plans acknowledge that imprudently incurred costs during MRP will be subject to refund, and be required to waive any claim that such a decision would be barred as a form of retroactive ratemaking?

Yes. DCG submits that the Commission has the authority to require that costs associated with imprudent investments be refunded to customers. A few examples of this type of action taken by other commissions are provided below:

- In July 2019, the Illinois Commerce Commission ordered Peoples Gas to refund $7.2 million to customers for imprudently incurred costs related to gas pipe and other infrastructure replacement work that the utility incurred in 2015. These costs were recovered through the "Qualifying Infrastructure Plant" rider, which are subject to later reconciliation. The Commission's rules provide that the costs are recoverable so long as they were prudently incurred.[20]

[20] Illinois Commerce Commission, Order in The Peoples Gas Light and Coke Company Petition pursuant to Rider QIP of Schedule of Rates for Gas Service to Initiate a Proceeding to Determine the Accuracy and Prudence of Qualifying Infrastructure Investment, Docket 16-0197, July 17, 2019. Available at https://www.icc.illinois.gov/downloads/public/edocket/503699.pdf

- In 2013, the Missouri Court of Appeals upheld an order from the Missouri Public Service Commission requiring that Ameren refund $17 million to ratepayers following prudence review of a rate adjustment under a fuel adjustment clause. The Court held that the commission "did not err in ordering a refund to Ameren's ratepayers. See Util. Consumers Council, 585 S.W.2d at 59–60 (holding that where a utility has no legal right to retain monies unlawfully collected, a refund may be ordered to avoid a windfall to the utility, as to hold otherwise "would leave customers without a remedy")."[21]

XI. ROE AND CAPITAL STRUCTURE IMPLICATIONS

Panel 1, Q16. Are there ROE and capital structure implications related to alternative forms of regulation?

Yes. MRPs are generally regarded as credit-positive. In general, rating agencies assess credit risk based on the stability and predictability of revenue streams and the timeliness of recovering costs. Use of forward-looking measures is viewed positively, as is support during times of stress. MRPs provide stable and predictable revenue streams (particularly when a revenue decoupling mechanism is in place), and allow revenues to be escalated between rate cases, providing more timely cost recovery. By reducing regulatory burden, MRPs also enable the utility to allocate resources to running the business rather than rate case administration. All of these factors contribute to MRPs being viewed as credit-positive. Thus, it is reasonable to take these factors into account when determining the utility's allowed ROE under an MRP.

Reconciliations are also associated with changes to the utility's risk profile. The New York Public Service Commission recognized this when it stated:

> Reconciliation provisions have the effect of stabilizing earnings and providing utilities a better opportunity to achieve allowed returns on equity. Both effects make New York utilities more attractive to many investors by decreasing the volatility of a company's earnings. We appropriately give consideration to how reconciliations transfer risk to ratepayers when determining the appropriate return on equity to allow in rate proceedings. This is one of the prime reasons returns allowed in New York are and can be lower than those in many other jurisdictions.[22]

[21] Missouri Court of Appeals, Western District. State Ex Rel. Union Electric Company d/b/a Ameren Missouri, Respondent, v. Public Service Commission of Missouri, Appellant, Missouri Industrial Energy Consumers, Appellant. Nos. WD 75403, WD 75404. Decided: May 14, 2013. https://caselaw.findlaw.com/mo-court-of-appeals/1633688.html

[22] New York Public Service Commission, Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030 et al, February 21, 2014 at 30

To the extent that reconciliations of any categories of costs are allowed, the ROE should be reduced to account for the reduction in the utility's risk.

Panel 2, Q8. How have the credit rating agencies viewed the implementation of alternative forms of regulation for electric and natural gas distribution utilities?

Please refer to the above response. For example, we note that last week Moody's wrote that

"[Connecticut Natural Gas's] credit is also supported by the low business risk profile of its fully regulated natural gas distribution operations, credit supportive features of the of Connecticut regulatory environment (e.g., multi-year rate plans and revenue decoupling mechanisms) and improving cash flow to debt ratios."[23]

XII. RATE DESIGN AND REVENUE ALLOCATION

Panel 1, Q10. Should rate design (revenue requirement allocation to various customer classes) stay the same for all the rate years within an MRP? If not, what factors should the Commission consider in evaluating whether an alternative rate design proposal provides ratepayers with benefits that they do not receive under the traditional rate design?

DCG recommends that the revenue allocation and rate design be generally held stable until the next rate case, since the utility will not have conducted a new cost of service study between rate cases. For the residential class, however, DCG recommends that the fixed charge be held constant and any rate changes be implemented through the volumetric rate.

XIII. PERFORMANCE INCENTIVE MECHANISMS

Panel 1, Q5. What specific performance outcomes and targets by the public utility should be measured and reported, inclusive of those aligned with the District's clean energy goals, including effects on global climate change and the District's public climate commitments, and how should performance targets and outcomes be measured? Identify and discuss other areas of public utility performance that should be measured and reported to the Commission, why they should be measured and their importance to the public interest? Are such performance outcomes and targets applicable to electric utilities, natural gas utilities, or both?

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[23] Rating Action: Moody's changes Connecticut Natural Gas' outlook to positive; Berkshire Gas' outlook to stable. Oct 22 2019, Available at https://www.moodys.com/research/Moodys-changes-Connecticut-Natural-Gas-outlook-to-positive-Berkshire-Gas--PR_412081

Panel 1, Q6. Besides the following key goals of utility regulation (traditional or performance-based) which include reasonable, affordable rates, reliable service, customer service and satisfaction, and environmental performance, please identify and discuss any additional key goals for the electric utilities for which performance metrics should be developed.

Under an MRP regulatory framework, utilities retain some or all of the savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, regulators have historically coupled MRPs with PIMs to prevent service quality degradation. DCG believes that it is generally appropriate for these PIMs to be penalty-only, as they relate to the core duties of a public utility (i.e., safe, reliable service). Further, continual improvement in reliability and customer service may provide diminishing returns.

PIMs are also increasingly being used to promote other outcomes, such as emissions reductions, as well as to ensure that a utility follows through on its commitments, such as investments in grid modernization.

DCG submits that PIMs should be developed carefully and be specifically designed to address performance gaps, rather than reward the utility for what it already is doing. In particular, DCG has identified the following significant gaps, which DCG recommends be addressed through metrics or full PIMs:

- Collection of, and access to, real-time system performance data and hosting capacity by government agencies and third parties, including technology-specific hosting capacity, downloadable data, and a public map of interconnection queue at the feeder level;

- Improvements in Distributed Energy Resources (DER) and load forecast modeling;

- Quantification of the values of DER services and costs;

- Implementation of appropriate tariffs and compensation schedules for grid services provided by DER, including microgrids and Virtual Power Plants, for the development of distribution-level ancillary markets and the provision of better price signals to customers;

- Implementation of cost-effective smart grid sensing, controls, and communication devices that enable coordinated, real-time interaction between customer-sided resources and the distribution grid;

- A technology investment roadmap and timeline for the installation of a smart grid infrastructure that includes a benefit-cost analysis of the Company's proposal;

- Implementation of a fully-integrated, robust, and transparent distribution system planning process;
- Implementation of cost-effective NWAs; and
- Greenhouse gas emission reductions from utility infrastructure investments and operations.

For more information, DCG directs the Commission to its Department of Energy and Environment's comments in FC 1130, filed on September 16, 2019.

XIV. EXPERIENCE WITH ALTERNATIVE FORMS OF REGULATION

Panel 2, Q9. What has been states' experiences with how alternative forms of regulation, and specifically an MRP, affects the public utility's incentive to improve its cost performance?

In general, jurisdictions that have implemented alternative forms of regulation with wide-ranging cost true-ups (such as FRPs) have seen a deterioration of utility incentives to contain costs. For example, in 2015, Act 725 was passed in Arkansas requiring that the Commission approve FRPs, but capped revenue increases under an FRP to 4% per year. Following passage of the Act, Entergy Arkansas, Inc. filed for an FRP. In each subsequent year, Entergy has requested rate increases exceeding 4%, leading to concerns that the formula rate plan has not provided appropriate cost containment incentives. In a recent order, the Arkansas Public Service Commission stated that "many of the FRP processes, including a reduction in the time afforded for review, the use of projections, and annual rate adjustments do little to incentivize a utility to control its costs as compared to traditional ratemaking."[24]

Where index-based MRPs have been implemented with little or no true-up of costs, there is evidence that utilities have sought to aggressively contain costs, with mixed results for service quality. For example:

- In his technical conference presentation, David Littell of the Regulatory Assistance Project provided an example of Pacific Northwest Bell, which drastically cut customer service and charged customers for accessing customer service.[25]
- On the other hand, Maine successfully implemented an MRP for nearly 20 years. During this time, Central Maine Power's productivity increased well above the average productivity level of other utilities, and the utility was able to offer

[24] Arkansas Public Service Commission, Order No. 21, Docket 16-036-FR, July 5, 2019.

[25] Littell, David, and B. Shur. Performance-Based Regulation: Modernizing the Energy Delivery System for Increased Sustainability. Presentation to the District of Columbia Public Service Commission Alternative Ratemaking Technical Conference, October 17, 2019, at 23.

flexible contracts to retain large customers on the system for the benefit of all customers. Some of this improvement in productivity was the result of improved efficiencies (a positive outcome), while some of it was related to deferred maintenance (generally a negative outcome). During the plan, service quality was tracked with PIMs. Service quality targets were generally met or exceeded. However, some areas were prioritized over others since the PIMs only tracked system-wide performance, rather than individual feeder performance.[26]

Panel 2, Q10. What has been states' experiences with how alternative forms of regulation, and specifically an MRP, affects the public utility's non-cost related performance?

PIMs have been implemented together with an MRP to address a utility's non-cost related performance. The strength of these PIMs is directly tied to the magnitude of the financial incentive associated with them, as well as to the clarity of the metric and review process. The success of the PIMs also relates to what exactly is incentivized (e.g., an outcome or simply spending on a particular program.) We provide a few examples and references below.

- PIMs have been used for many years for energy efficiency and have been widely regarded as successful. In particular, "multifactor incentives" for energy efficiency, which set metrics for goals in addition to energy savings, are widely used by the most successful states. In contrast, some states simply provide the utilities with an ROE adder on energy efficiency program costs, which serves to reward the utility for spending more money, but not for actually achieving outcomes. We recommend avoiding such PIMs and focusing on outcomes, to the extent possible. For additional information, please see ACEEE's *Snapshot of Energy Efficiency Performance Incentives for Electric Utilities.*[27]
- Several examples of various jurisdictions' experiences with PIMs are provided in Appendix A of the attached report, *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, authored by Synapse Energy Economics.[28] The report provides examples of how financial incentives for utilities can result in windfall profits, and how utilities have gamed PIMs in the past. It also provides a discussion the New York Public Service Commission's efforts to encourage distributed energy resource development through PIMs.

[26] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), https://escholarship.org/uc/item/4r13j347.

[27] American Council for an Energy-Efficient Economy, "Snapshot of Energy Efficiency Performance Incentives for Electric Utilities," December 2018, https://aceee.org/sites/default/files/pims-121118.pdf.

[28] The full report is also available online. *See:* Melissa Whited, Tim Woolf, and Alice Napoleon, "Utility Performance Incentive Mechanisms: A Handbook for Regulators" (Synapse Energy Economics, March 9, 2015), http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

XV. ADDITIONAL RULES AND REGULATIONS

Panel 2, Q12. What rules or regulations should the Commission implement if it decides to move forward with alternative forms of regulation?

DCG believes that the Commission should start with considering PIMs that will advance grid modernization, layered on a traditional base rate filing. Initially, these PIMs could be information-driven PIMs without reward or penalty, and the utility should be able to recover the costs associated with implementing and reporting on the PIMs.

Once the Commission has enough specific information about how these PIMs could be used to advance grid modernization, it could consider providing reward or penalty for these PIMs. DCG reiterates that while well-designed PIMs could expedite grid modernization, an MRP is not essential for grid modernization. Any proposals for PIMs should:

1. Specifically identify the policy or objectives that each PIM is designed to address;
2. Identify whether each PIM target or objective is already addressed by any existing standards, metrics, or requirements;
3. Identify specific PIM metrics, targets, and incentives (if any) for each proposed PIM;
4. Explain the rationale and methodology by which each PIM target was developed;
5. Specifically identify what incentives and disincentives the utility currently faces regarding achievement of each PIM target;
6. Be accompanied by 10 years of historical performance data (where available) for each PIM;
7. Be reasonably verifiable;
8. Provide a baseline forecast of performance without each PIM, together with supporting data and an explanation of the methodology used to calculate the baseline;
9. An estimate of the incremental utility costs associated with achieving each PIM target, together with the specific actions the utility may take to achieve the PIM target with supporting data and workpapers; and
10. An estimate of the benefits to ratepayers (including climate change impacts) of achieving the PIM target (relative to the baseline level of performance), accompanied with supporting workpapers.

That said, if the Commission believes that an MRP must be paired with PIMs to help advance grid modernization, we highlight the following guidelines:

1. MRPs must be based on a historical test year, with adjustments allowed according to current Commission practice and to account for inflation.
2. Any proposed MRP that includes a proposal to escalate revenues over the plan must use one or more external cost indexes rather than the utility's own cost forecasts. At the Commission's discretion, exceptions may be made for the following:
    a. Large, unusual investments that are necessary to achieve public policy goals;
    b. Recurring costs that are volatile and outside of utility control; and
    c. One-time exceptional costs that have a material effect on the utility's costs, are beyond the control of utility management, and which were incurred reasonably.
3. Any cost forecasts associated with categories of costs listed in 2(a)-(c) must be accompanied by supporting documentation and justification.
4. Revenues based on cost forecasts shall be subject to an annual one-way (downward) reconciliation mechanism.
5. The utility's allowed ROE should be adjusted to reflect the credit-positive nature of MRPs.
6. A utility may file an MRP no more frequently than every 36 months from the date of filing its most recent MRP.
7. Any MRP should be paired with PIMs designed to prevent service degradation, and such PIMs should be penalty-only, as explained in the foregoing.

XVI. Appendix – Case Studies

Multi-Year Rate Plan Examples

Massachusetts Index-Based MRP

Overview: Eversource Energy operates under an MRP that uses a revenue-indexing mechanism to adjust base rates, plus reconciliation of certain exogenous costs. The MRP has a five-year stay out period.

Revenue Index: Eversource's MRP allows for an adjustment of Base Rates using the rate of input price inflation representative of the electric distribution industry, less offsets for productivity and a consumer dividend.

Annual Adjustments: Effective January 1 of each year, the utility's Base Revenue Requirement is adjusted through an adjustment formula equal to the percentage change in the US Gross Domestic Product Price Inflation (GDPPI), plus a productivity adjustment of 1.56% minus a consumer dividend of 0.25%, plus an adjustment for exogenous costs.

Reconciliation of Exogenous Costs: Exogenous costs must (1) be beyond the utility's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives; (3) be unique to the electric industry as opposed to the general economy; and (4) meet a threshold of "significance" of $5 million. The utility must present supporting documentation and rationale to the Department of Public Utilities (DPU) for consideration. Once allowed by the DPU, the cost is recovered or returned in a separate factor to be reviewed and approved by the DPU.

Customer Protections: Earnings Sharing provides an important protection for customers in the event that expenses increase at a rate much lower than the revenue increases generated by the MRP revenue index. If the utility's actual ROE exceeds the utility's allowed ROE by 200 basis points, 75% of any additional earnings must be shared with customers.[29]

Grid Modernization Factor

Utilities may hesitate before making investments with high capital costs, particularly when combined with regulatory lag and the potential for disallowances. To encourage grid modernization, the Massachusetts DPU approved a targeted cost recovery mechanism called the "Grid Modernization Factor" or "GMF" for investments that are preauthorized by the DPU. All grid modernization-related capital and O&M expenditures are recovered separately and are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the Grid Modernization Factor shall not exceed the preauthorized three-year budgets.

Pre-authorization of Grid Modernization Investments and Budgets: All grid modernization-related capital and O&M expenditures are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the GMF shall not exceed the preauthorized three-year budgets.

Cost Recovery of Grid Modernization Costs: Costs are only eligible for recovery after the expenses have been incurred and the investments have been placed in service. The utilities file annual GMF rate adjustment and reconciliation filings comprised of: (1) actual, eligible preauthorized expenditures from the prior grid modernization plan investment year; and (2) a reconciliation component in the second year and beyond. Interest on over- or under-recovery of the revenue requirement is calculated on the average monthly balance using the customer deposit rate.

Annual Reconciliation Filings for Grid Modernization Costs: On an annual basis, the utilities must file testimony and supporting exhibits with full project documentation

[29] *See*: Massachusetts Department of Public Utilities, Order D.P.U. 15-122, May 10, 2018, at 216-235. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163507 and NSTAR Electric Co. d/b/a Eversource Energy, Tariff Sheets M.D.P.U. No. 59A, filed February 16, 2018.

of all grid modernization capital projects placed into service during the plan investment year and documentation of O&M expenses. The utilities must demonstrate that the costs sought for recovery are preauthorized, incremental, prudently incurred, in service, and used and useful (where applicable). Additionally, the filing shall also describe any cost variances as defined in the Companies' capital authorization policies, provide a demonstration that the proposed factors are calculated appropriately, and provide bill impact estimates.

MRPs based on Cost Forecasts

Minnesota's MRP Based on Cost Forecasts with One-Way Reconciliations

When Minnesota was developing its rules for MRPs, various parties proposed different approaches to revenue adjustments during the rate plan.

- The Minnesota utilities favored formula rates, arguing that these rates could be more useful because they would adjust to reflect the latest data.
- Other parties opposed the use of automatic formulas for the purpose of adjusting rates to reflect new costs. They argued that formula rates would reduce a utility's incentive to operate efficiently and would be burdensome to supervise. Instead, these parties favored fixed multiyear rates. The rate case would establish the rates to be charged in each year of the MRP; the rates for the first year might differ from the rates for later years, but the base rates for all years would be known by the end of the rate case.

Ultimately the Minnesota Public Utilities Commission (PUC) declined to approve multiyear rate plans that rely on formula rates, noting that such rates reduce a utility's incentive to manage its costs. Moreover, the Commission observed that formula rates are unnecessary to achieve the purpose of an MRP, stating that "Fixed multiyear rates permit prices to adjust over time to reflect anticipated changes in a utility's circumstances, yet can be established in a fact-driven ratemaking process built on a substantial evidentiary record." Consequently, the Commission directed utilities to propose fixed rates for each year of their plan when filing an MRP.[30]

In 2017, the Minnesota PUC approved a settlement regarding Xcel Energy's MRP application. The utility's initial application requested revenue increases supported by substantial documentation of the utility's proposed cost of service. During settlement

[30] Minnesota Public Utilities Commission, Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, June 17, 2013, at 6-7, available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b2747CB67-C5F2-48D8-8155-0FF97F926FD6%7d&documentTitle=20136-88242-01

proceedings, the annual revenue requirements were adjusted downward substantially, and generally became divorced from actual project costs.

The Minnesota PUC ultimately found the settlement reasonable, despite it no longer being tied to specific project costs, as the yearly rate increases were less than inflation and significantly less than what Xcel initially proposed. Further, the settlement prohibited Xcel from filing another rate case for four years or from seeking to institute any new riders for four years.

As an additional consumer protection measure, the settlement adopted a one-way capital-spending true-up, meaning that Xcel will make refunds if it spends less than it budgeted but cannot increase rates if it spends more. The true-up is based on aggregate capital spending, rather than individual projects. The Minnesota PUC found that a true-up based on the aggregate amount of capital spending was reasonable given that Xcel's budget included approximately 1,800 capital projects. Nonetheless, the Minnesota PUC also required that Xcel work with the Commission and Department of Commerce Staff to develop an annual capital-projects true-up compliance report that provides more granular data regarding project spending.[31]

New York's "Claw-Back Mechanism"

A one-way reconciliation mechanism is used in New York and referred to as the "Net Plant Reconciliation Mechanism" or "claw-back mechanism." The New York Public Service Commission (PSC) describes this mechanism for Consolidated Edison as follows:[32]

> If the Company's actual average net plant in service for each of the three categories of capital expenditures is less than that category's projected average plant-in-service balance…, the Company will defer the carrying costs associated with the difference for the benefit of ratepayers. If the Company exceeds the net plant-in-service targets, it must absorb the related carrying costs during the term of the rate plan. Con Edison must justify the need for, the reasonableness of, and its inability to reasonably avoid any such over-target expenditures in its next rate case filing. In addition, the revenue requirement associated with any such Commission-approved over-target expenditures from Rate Year 1, after the term of the rate plan and for the book life of the investment, will be calculated based on an assumption

[31] Minnesota Public Utilities Commission, Findings of Fact, Conclusions, and Order, Docket E-002/GR-15-826, June 12, 2017.

[32] New York Public Service Commission, Order Establishing Three-Year Electric Rate Plan, Case 09-E-0428, March 26, 2010, at 11.

that the over-target expenditures were not financed by both common equity and debt, but rather solely by debt.

Formula Rate Plans

Alabama Power's Formula Rate Plan

Overview: Alabama Power Company operates under an FRP called the "Rate Stabilization and Equalization plan." Each year, the Alabama Public Service Commission (PSC) compares the utility's projected ROE for the next year to its authorized ROE. If necessary, the utility's base rates are adjusted to keep the expected ROE within the authorized range, following a review of the reasonableness of the utility's costs.

Reconciliation Process: By December 1 of each year, the utility provides the Alabama PSC with its projected ROE for the next year, together with an analysis of the main causes of any deviations from its authorized ROE and the need for any rate adjustment. During December, parties review and discuss the need for the rate adjustment, with any adjustments going into effect in January.

Customer Protections: Annual rate adjustments are capped at 5% to reduce rate shock. Once the utility's revenues are adjusted to match its projected costs for the upcoming year, the onus is on the utility to keep costs in check. If the utility fails to achieve its allowed ROE, no further reconciliation is made. However, if the utility's ROE exceeds its allowed ROE, then the excess is refunded to customers.[33]

Entergy Arkansas, Inc.'s Formula Rate Plan

Overview: As required by 2015 Ark. Acts 2015 725, §3, formula rate plans in Arkansas use a formula based on the difference between a utility's target and earned return. If the utility's earned return exceeds its target return by 50 basis points, it is required to reduce its rates. Likewise, if the utility's earned return falls below its target return by 50 basis points, it is allowed to increase its rates.

Cost Forecasts: The utility may choose to use a projected test year or a historical test year. If a projected test year is used, the utility must file its cost forecasts in July of each year for the next calendar year period.

Reconciliation Process: If a projected test year is used, rate changes must include an adjustment to net any differences between the prior formula rate review test period change in revenue and the actual historical year change in revenue for that same year.

Regulatory Review: The review of cost forecasts, reconciliation, and approval of new rates occurs in a 180-day process that includes a public hearing.

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[33] Laurence Kirsch and Mathew Morey, "Alternative Electricity Ratemaking Mechanisms Adopted by Other States" (Christensen Associates Energy Consulting, May 25, 2016), p. 11, available at https://www.caenergy.com/wp-content/uploads/2016/02/Kirsch_Morey_Alternative_Ratemaking_Mechanisms.pdf.

Customer Protections: Annual rate adjustments for each rate class are capped at 4%.[34]

Staff and Commission Concerns Regarding the FRP: Following passage of the Act, Entergy Arkansas, Inc. filed for a formula rate plan. In each subsequent year, Entergy has requested rate increases exceeding 4%, leading to concerns that the formula rate plan has not provided appropriate cost containment incentives. As explained by the Arkansas PSC Staff,

> An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility…. The ability to increase revenues 4% each year is a considerable risk reduction for the utility.[35]

More specifically the Staff noted that an FRP:

- Reduces the time afforded for review of utility costs, which can serve to incentivize spending;
- Allows projections on projections, which incentivizes spending as compared to a regulatory framework where projections are based on what is otherwise historical information from which to make known and measurable changes;
- Incentivizes spending due to the annual rate adjustments. Once the FRP framework is selected by a utility, an outcome of a 4% increase each year (over the prior year) is less subject to challenge as long as the costs are prudently incurred and calculated in accordance with the tariff. The traditional regulatory tools in the Commission's toolkit are more limited under the FRP framework as the Commission has recognized; and
- The unstated implication of the FRP statute is that the risk of an earnings review is effectively eliminated. There is no clear incentive to contain costs between annual FRP 4% increases. While the FRP framework states the rate change may be an increase or a decrease, the likelihood of a decrease is highly unlikely.[36]

In its order, the Arkansas PSC agreed with Staff, stating that "many of the FRP processes, including a reduction in the time afforded for review, the use of projections, and annual rate adjustments do little to incentivize a utility to control its costs as compared to traditional ratemaking."[37]

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[34] AR Code § 23-4-1207 (2015) https://law.justia.com/codes/arkansas/2015/title-23/subtitle-1/chapter-4/subchapter-12/section-23-4-1207/

[35] AR PSC Staff, Initial Brief Pursuant to Order No. 18, Docket 16-036-FR, January 1, 2019, at 17.

[36] *Id.,* at 18-19.

[37] Arkansas Public Service Commission, Order No. 21, Docket 16-036-FR, July 5, 2019.