BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

Notice of Inquiry into the Adequacy of the Current Regulatory Framework Employed by the Commission in Addressing Developing Industry Trends, New Technologies, and Public Policy Affecting the Utility Sector

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DOCKET U-180907

INITIAL COMMENTS OF PUBLIC COUSEL

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January 17, 2019

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I. BACKGROUND AND INTRODUCTION

1. On November 9, 2018, the Washington Utilities and Transportation Commission (WUTC or Commission) issued a Notice of Workshop to discuss the Adequacy of the Current Regulatory Framework. The initial Workshop, held on December 10, 2018, provided a broad array of stakeholders the opportunity to discuss issues with the current regulatory framework and some potential solutions and regulatory mechanisms to address their concerns. The Commissioners suggested that the stakeholders in attendance at the initial Workshop should detail their "problem statement" and respond to issues and concepts raised by other stakeholders present on December 10. In light of the request at the Workshop, the Commission issued a Notice of Opportunity to File Written Comments on December 17, 2018.

2. Public Counsel, in collaboration with Michael L. Brosch of Utilitech, Inc., responds to the Commission's December 17, 2018 Notice. In these comments, Public Counsel will identify the issues, problems, and principles that should be prioritized as goals for the Commission's attention in this docket. The current regulatory framework forms the basis for utility ratemaking and regulatory oversight in Washington. The "problem" under consideration is whether the current regulatory framework is failing to meet the State of Washington's objectives. If change is deemed necessary, the Commission must determine how to define and prudently implement changes to the framework to improve utility performance and satisfy the highest priority goals of regulation. These goals include utility service affordability, utility cost control incentives, service reliability, resilience and safety, customer empowerment, and customer equity. Throughout these comments, Public Counsel will emphasize the critical distinctions between traditional cost of service regulation (COSR) and performance-based regulation (PBR).

3. Public Counsel encourages the Commission to embrace changes to the existing regulatory framework in Washington only after careful and deliberate consideration of the advantages and disadvantages of COSR and only after identifying specific problems arising from the current regulatory framework. The Commission's evaluation of the existing framework should determine how each regulatory mechanism within the framework is achieving, or failing to achieve, the prioritized goals identified by the Commission and stakeholders. The Commission's evaluation should be based firmly on facts.

4. If change is found to be appropriate, it is unlikely that any specifically defined new regulatory framework will be well suited to every one of Washington's utilities. Rather, each utility may require a more tailored specification of revised regulation that fits its operational and financial circumstances. Therefore, the Commission should initially focus in this docket upon approval of broad guidelines and policies for directional and evolutionary changes in regulation (once change is determined to be appropriate). The details of implementation of any modified regulatory mechanisms would then be developed in a manner sensitive to the unique facts and circumstances of each utility in future proceedings, where utility specific evidence can be fully considered.

5. When changes are made to regulatory policy and mechanisms, the devil is firmly in the details. These critical details are fact specific and not uniform across all utilities and service areas. Public Counsel appreciates the Commission's desire to comprehensively investigate the adequacy of Washington's regulatory policies and mechanisms and intends to participate with an interest in improving utility performance, minimizing the risk of unintended consequences, and advancing the public's interest in safe and reliable utility services at reasonable rates.

II. THE PROBLEM IN PERSPECTIVE

6. The "problem" continuously faced by regulators is how to best determine just and reasonable rates that comply with applicable laws and reasonably balance the interests of utility ratepayers and shareholders. In this investigatory docket, the Commission is considering the threshold question of whether Washington's existing regulatory framework, which relies primarily upon COSR, should be changed. This question can only be answered by evaluating the characteristics of Washington's existing regulatory framework to determine whether it is capable of meeting the most important goals established by the Commission within the evolving technological and public policy environment. This evaluation is challenged by the fact that certain public policies remain in debate, although stakeholders generally agree that policy decisions will ultimately be made.

7. Any discussion of the adequacy of the State's current regulatory framework in addressing developing industry trends, new technologies, and public policy should begin with an appreciation of how Washington compares to other states relative to such trends. To varying degrees in different markets, electric utilities face new pressures to the single-provider, central station generation model that has been well-served by traditional COSR. Technological changes are creating new customer choice options and imposing broader changes to the electric utility business model, forcing a reexamination of the existing framework of regulation in many jurisdictions. The driving factors for reconsideration of electric utility regulation now include:

- Declining cost Distributed Energy Resources (DER), including distributed wind generation and rooftop photovoltaic (PV) panels that are challenging traditional electric transmission and distribution business models and schemes of regulation.
- Improved information technologies that enable various smart grid applications, including demand response (DR) programs, micro-grids, and the provision of time sensitive and unbundled rate structures.
- Adoption of cloud-based solutions to information technology requirements and the utilization of other third-party vendors for contract services that historically relied upon assets constructed and owned by utilities.
- Electrification of transportation that is creating new markets for electric utilities and new interconnection, service, and pricing needs for consumers.
- Increasing focus upon social and environmental issues that were less emphasized in prior times, including energy efficiency and renewable portfolio standards.

8. These and other changes are often cited as creating a growing need to explore potential improvements to the traditional electric utility COSR framework that relies upon periodic rate cases that linked electricity pricing to the underlying expenses and investment levels actually incurred, or forecasted as needed by the utility, to provide service. Notably, the relative urgency of needed changes to COSR caused by these trends differs materially from state to state. Utilities in Washington are only beginning to see impacts in these areas, and COSR in its present form or with modest modification may serve us well for years to come. In contrast, several other states, such as Hawaii and New York, are immersed in technological and policy upheavals and are systematically dismantling traditional COSR in favor of more Performance Based Regulation (PBR). These states are turning to Multi-year Rate Plans, Performance Incentives, and other creative alternatives to traditional rate cases.

9. As the Commission and stakeholders consider changes to the existing regulatory framework, the characteristics of Washington and its ratepayers must be considered. For example, Distributed Energy Resources[1] (DER) are not as prevalent in Washington as in several other states. According to the Solar Energy Information Association, as of the 3rd quarter of 2018, Washington had only 136 megawatts of distributed and utility installed solar energy within 16,722 systems statewide.[2] These values represent significantly less than a percent of the nationwide totals of 60,000 megawatts of solar capacity and 1.9 million installations, even though approximately 2.2 percent of the U.S. population lives in Washington.[3] This is likely the result of higher energy costs in other states, more favorable solar irradiance in some states, and differences in net energy metering and other interconnection policies.

10. One key difference is that the delivered price of electricity in Washington is lower than in most other states, which offers less encouragement for competing technologies. According to Electric Power Monthly data released in December 2018, the average price of electricity to residential consumers in Washington was 9.68 cents per kWh, about 75 percent of the national average. More specifically, average residential rates in Washington are much lower than the 32.46 cent and 19.29 cent residential average prices paid in Hawaii and New York, respectively.[4] While beneficial to ratepayers, the relatively favorable electricity prices in Washington tend to reduce the economic "payback" on energy efficiency and utility investments in smart grid applications, demand response measures, microgrids, and the adoption of more complex rate

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[1] Distributed Energy Resources (DER) consists of small-scale units of local generation connected to the grid at the distribution level. Roof-top solar is a common example of DER.

[2] *Solar Spotlight – Washington*, SOLAR ENERGY INDUSTRIES ASSOCIATION, https://www.seia.org/sites/default/files/2018-12/Federal_2018Q3_Washington.pdf (last visited Jan. 17, 2019).

[3] *See Solar State by State Map*, SOLAR ENERGY INDUSTRIES ASSOCIATION, https://www.seia.org/states-map (last visited Jan. 16, 2019). For July 1, 2015 census estimates by state, *See Annual Estimates of the Resident Population: April 1, 2010 to July 1, 2017*, U.S. CENSUS BUREAU, https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=PEP_2017_PEPANNRES&src=pt.

[4] *See* U.S. ENERGY INFORMATION ADMIN., ELECTRIC POWER MONTHLY DATA FOR OCTOBER 2018, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a (last visited Jan. 16, 2019).

structures. Lower energy prices also tend to reduce the opportunity for competitive third-party competition for new utility-scale resources that are emerging in other states where regulated electricity prices are generally higher. The existing regulatory policies and the structural advantages that have contributed to favorable energy prices in Washington should not be hastily discarded in favor of untested new regulatory approaches that may reduce these advantages.

11. Washington has adopted a Renewable Portfolio Standard of 15 percent by 2020, which is presently less aggressive than RPS policies established in many other states. Oregon has set RPS of 50 percent by 2040, California is 60 percent by 2030, New York is 50 percent by 2030 and Hawaii is 100 percent by 2045.[5] Ambitiously high RPS targets are more difficult to achieve without regulatory reforms that are more supportive of interconnection of competing DER facilities, grid modernization, open access information systems, and utility capital formation than traditional COSR. Proposed legislation in Washington would match Hawaii's 100 percent by 2045 RPS goal, if approved, and may create new responsibilities for the Commission to consider when revisions to the regulatory framework are analyzed and eventually developed for implementation.[6]

12. Public Counsel's comments will provide a policy-level overview of the characteristics of traditional COSR of electric utilities, highlighting the strengths and weaknesses of historical approaches. Then, the comments will present an overview of the various approaches to and elements of Performance Based Regulation (PBR), again with a discussion of strengths, weaknesses and implementation issues. Finally, Public Counsel offers recommendations with respect to procedural steps the Commission may elect to follow to first prioritize the goals of the regulatory process, evaluate whether each of the existing regulatory mechanisms is sufficiently

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[5] *See State Map of Renewable Portfolio Standard Policies*, NC CLEAN ENERGY TECHNOLOGY CENTER, http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2018/10/Renewable-Portfolio-Standards-2018.pdf (last visited Jan. 16, 2019).

[6] SB 5116, 66th Leg., Reg. Sess. (2019), https://app.leg.wa.gov/billsummary?BillNumber=5116&Year=2019&Initiative=false.

supportive of such goals, identify where changed approaches are appropriate, and then develop a process for the detailed design and implementation of changes that are tailored to each utility.

III. TRADITIONAL REGULATION – STRENGTHS AND WEAKNESSES

13. COSR remains the fundamental driver of electric utility ratemaking in Washington and most other state jurisdictions.[7] Periodic rate cases, along with an extensive complement of rate adjustment riders and cost deferral/recovery mechanisms in some jurisdictions, serve as the primary methods used to adjust pricing to track changes in costs.

14. The frequently noted **advantages** of COSR regulation include:

- COSR inputs used for pricing are fact-based and verifiable, reducing the dependence upon assumptions and forecasts to determine reasonable and necessary revenue requirements. Even in jurisdictions that employ forecasted test years, the availability of actual cost data provides an important benchmark for forecast evaluation.
- Financial stability of utilities and access to capital on reasonable terms is more assured when revenues are established in a manner that comprehensively and timely recovers most of the costs incurred to provide service.
- Reduced risks are shouldered by investors and reflected somewhat within authorized equity returns when electric utilities are able to request and receive recovery of increasing costs, relative to more performance based AFOR regimes.
- Regulatory "lag" in the timing of revenue recovery for increasing costs (that are not included in rate adjustment trackers or deferrals) provides modest incentives to utility

[7] While states, including Washington, have implemented MYPs, 27 states have not done so or have MYPs that have expired. Three additional states have MYPs that have expired. *See* M.N. LOWRY ET AL., GRID MODERNIZATION LABORATORY CONSORTIUM, STATE PERFORMANCE-BASED REGULATION USING MULTIYEAR RATE PLANS FOR U. S. ELECTRIC UTILITIES, at 2.3 fig. 1 (2017), http://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

management for cost control, since increasing costs between rate cases negatively impact earnings.

- Service quality and resilience is more assured when the utility is able to recover the costs incurred to provide good service.
- Compliance with environmental, renewable energy, energy efficiency and other public policy goals and rules is more assured when the utility can expect to fully recover the costs incurred to achieve and maintain compliance.

15. The frequently noted **disadvantages** of COSR regulation include:

- Higher costs are systematically rewarded with higher revenues, resulting in diminished incentives for cost control, subject only to regulatory lag noted above.
- A throughput incentive exists, in the absence of comprehensive revenue decoupling, where growth in KW/KWH sales between test years will increase earnings. This incentive may diminish management's commitment to support energy efficiency and demand response measures and may discourage DER interconnection.
- Electric utility earnings increase when rate base investments are added, creating a perverse incentive favoring capital investment over expensed contracted services, while discouraging support for DER owned by third parties that displace utility-owned assets.
- Administrative complexity and increased regulatory costs incurred to process frequent rate cases and to effectively oversee numerous rate adjustment riders and cost deferral/recovery mechanisms.[8]

[8] Administrative complexity is a function of the frequency of filed rate cases along with the number of rate adjustment mechanisms that require periodic reconciliation filings and regulatory review. Adoption of Multiyear Rate Plans and Performance Incentive Mechanisms tend to introduce new and different filings. Complexities in the design and administration of such plans may not ultimately result in reduced Staff or stakeholder responsibilities and workloads.

- Utility performance, relative to established benchmarks, does not directly impact financial results unless the regulator imposes performance incentive measures with financial rewards and penalties.

16. The Washington Utilities and Transportation Commission (WUTC) has favored COSR using historical, rather than forecasted test years, and has addressed several of the listed disadvantages with several modifications adopted in past proceedings that have included:

- Decoupling for residential and small commercial customers, on a "revenue per customer" basis that reduces the throughput incentive and guarantees revenue growth when new customers are added, even as usage per customer declines.
- A negotiated multi-year rate plan (MRP) approved for Puget Sound Electric (PSE) that provided for a rate case moratorium and indexed price increases, with the goal of enhancing the incentives for cost control and avoiding rate cases during the term of the MRP. MRP has also been approved for Avista and Pacific Power.[9]
- Expedited Rate Filings (ERF) that are intended to reduce rate case frequency, while also diminishing the regulatory lag incentives to the utility for cost control.
- Service quality metrics and tariff provisions that penalize the utility for failing to meet customer service goals.

17. The Commission's past approvals of decoupling and negotiated forms of MRP represent gradual movement toward alternative regulation that is similar to actions taken in several other state jurisdictions. On the other hand, approval of ERF procedures represent movement in the other direction, regressively accelerating the translation of higher costs into higher prices.

[9] *WUTC v. Avista Corp.,* Dockets UE-120436 & UG-120437, Order 14, Final Order (Dec. 26, 2012); *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-121697 & UG-121705 (*consolidated*) and UE-130137 & UG-130138 (*consolidated*), Order 07, Final Order Authorizing Rates (June 25, 2013); *WUTC v. Pacific Power & Light Co.*, Docket UE-152253, Order 12, Final Order Rejecting Tariffs as Filed (Sept. 1, 2016).

Expedited rate cases dilute the regulatory lag incentive for management efficiency while limiting the ability of stakeholders to effectively participate in the proceedings.

18. Notably, the limited modifications to traditional regulation undertaken to date in Washington have been approved by the Commission in the absence of any legislation compelling such changes. Rather, these modifications occurred in the context of adjudications before the Commission and were decided on the facts presented in each individual case.

IV. PRIORITY GOALS FOR REGULATORY REFORM

19. Public Counsel does not view the existing regulatory framework in Washington to be "broken" or in need of urgent or dramatic change, because the framework appears to reasonably balance the public interest objectives of safe and reliable service at reasonable prices. In turn, current utility rates sustain access to capital markets on reasonable terms, where all of Washington's electric utilities maintain investment-grade credit ratings and consistently realize strong earnings.[10] However, there may be an opportunity for evolutionary changes to Washington's regulatory framework to better serve the public interest. <u>Public Counsel believes that changes to the regulatory framework should only occur when clearly defined regulatory goals are not being satisfied using existing regulatory mechanisms, and where the benefits of changed regulatory mechanisms clearly outweigh the risks and costs of making the change.</u>

20. The Commission appears to have recognized the first essential step in this sequence in its Request for Comment for the parties to "identify the problem statements and principles that are

[10] According to CBR Report calendar year results, Avista, Pacific Power and PSE experienced earned rate of return in excess of Commission-authorized levels in both 2016 and 2017. The electric utilities in Washington have consistently earned rates of return near or exceeding authorized levels in all years 2013 through 2017, indicating the adequacy of the existing regulatory framework in meeting the financial needs of electric utility shareholders. Avista Corp.: UE-180354, UE-170325, UE-160454, UE-150699, UE-140529; Pacific Power & Light Co.: UE-180364, UE-170329, UE-160463, UE-150700, UE-140739; Puget Sound Energy: UE-180255, UE-170221, UE-160375, UE-150528, UE-140536.

most important" and then "provide comments on problem statements and principles raised by other stakeholders during the workshop and provided in pre-filed comments."[11] Our problem statement was outlined above in Section II. Public Counsel respectfully submits that an additional opportunity to respond to other parties' filed comments should be provided for a more complete record. The first Workshop was not a formal proceeding where all parties and all positions were fully presented and explained, but rather was a first round of impressions that opened the door to further discussions in this proceeding. Additional comments on procedural steps that could be adopted by the Commission are provided in Section VII, below.

21. Public Counsel recommends that the Commission should first develop a list of ***priority goals*** to guide its evaluation of the existing regulatory framework and any future changes to the regulatory framework. It should be noted that there is inherent "tension" between several of these goals. For example, utility management efforts to maximize service quality or improved interconnection of renewable resources may necessarily compromise efforts to achieve cost control and affordability. It is essential that each change to existing regulatory mechanisms be carefully analyzed and calibrated to achieve an appropriate balance between cost and performance.

Public Counsel's Recommended Priority Goals

- *Affordability* – regulation should strive to maintain reasonable and stable customer bills, with a focus upon total energy costs to consumers and protection of low-income and other disadvantaged customers.
- *Utility Cost Control* – regulation should encourage efficient and optimal utility capital investments and operating expenses, mitigating the capital expenditure bias caused by COSR and encouraging an optimal balance of input resources. This goal must be properly balanced with the other goals listed below.

[11] *See* Notice of Opportunity to File Written Comments, at 1-2.

- *Reliability* – a high level of electric service reliability at reasonable cost, with an ability to adapt to changing conditions and rapidly recover from service disruptions.
- *Safety* – employee and public safety must remain a priority goal, given the inherent risks attached to electric utility service.
- *Customer Equity and Engagement* – reasonable sharing of costs and benefits of the current and future electric system across customer groups, with equal access to products, service, information, and opportunities to control energy bills.
- *Capital Market Access* – regulation should maintain utilities' financial integrity and access to capital on reasonable terms.
- *Advancing Washington's Public Policy Goals* – Where there is a nexus with the WUTC's authority and the state's policy goals, any modifications to the regulatory framework should help achieve them.

22. After the Commission considers these recommendations and the comments filed by other stakeholders, a logical next step would be to evaluate the extent to which <u>each</u> of the existing regulatory mechanisms that make up Washington's regulatory framework is supportive of the goals found to be of highest priority in the judgment of the Commission. Existing regulatory mechanisms should not be discarded or modified unless clearly desirable new alternatives are identified and carefully analyzed by the Commission. Then, any modified or newly created regulatory mechanisms must be defined with particularity and carefully calibrated to each utility to optimize performance across all priority goals in a manner consistent with the public interest.

23. In general, Public Counsel believes that the existing regulatory framework in Washington should be gradually modified, <u>only</u> where change is clearly needed to better support public interest goals of the highest priority, by carefully injecting elements of Performance Based Regulation to displace COSR where practical and cost-effective. A balancing of utility ratepayer and shareholder interests has been achieved within Washington's existing regulatory framework within many prior proceedings. The detailed design and calibration of any changes to the framework for each utility will require intensive study to maintain the established balance.

V. PERFORMANCE BASED REGULATION

24. The overarching goal of Performance Based Regulation (PBR) is to improve upon the disadvantages of COSR and more closely align regulatory incentives with public policy goals, all while not excessively compromising the more important advantages of traditional regulation. This statement is intended to highlight the tension created when moving away from COSR and toward alternative methods of determining electric utility compensation and performance tracking.

25. The design of any PBR plan involves many critical details that must be defined and calibrated, including forecasts of future events and outcomes that are inherently uncertain. Utilities maintain long-term financial models to predict future financial results and can be expected to support adoption of a PBR plan that produces more robust financial results, even under relatively pessimistic assumptions regarding future inflation, interest rates, customer demand, and other key modeling assumptions. Commissions and intervenors are less informed than management in forecasting long-term future outcomes and suffer from information asymmetry in the design of PBR parameters. While financial models are informative in guiding the design of a PBR plan, the future is inherently uncertain.

26. For example, PBR changes made to break the "link" between utility costs and revenues could be pursued by employing inflation and productivity indices within an MRP to replace frequent rate cases. Such an indexing approach will tend to increase risks to both the utility and its customers that the MRP plan design proves to be sub-optimal, yielding excessive or inadequate revenues in relation to actual costs. In extreme cases of poor PBR design, the utility's earnings and credit metrics may swing to unacceptably high or low levels during the term of the

MRP, creating either public relations issues at one end of the spectrum or financial stability and capital access problems at the other extreme. Attempts to moderate these financial outcomes can be designed into the plan by incorporating earnings monitoring and sharing provisions or off-ramps and mid-course corrections. These moderating provisions are often viewed as essential to the public interest, even though they tend to diminish some of the intended incentives.

27. It can be useful to consider PBR as an array of options that depart from COSR to varying degrees. In other words, updating the regulatory framework does not necessarily require scrapping COSR entirely and basing regulation exclusively on PBR. Several basic approaches to PBR are considered in this report, which can be deployed independently or jointly and have been applied across several jurisdictions in the US and in Canada and the United Kingdom.

- **Multi-year Rate Plans (MRPs)** that involve some combination of reduced frequency of rate cases and/or reduced dependence upon cost information to determine rate and revenue levels.
- **Performance Incentives Measures (PIMs)** defined using metrics and targets against which actual performance can be monitored and scored. To amplify the importance of PIMs to management, carefully calibrated financial rewards and/or penalties can be added to more directly incent desired outcomes.
- **Preferential Cost Recovery (Trackers)** can be provided to encourage desired types of spending for energy efficiency programs, renewables interconnection, and RPS achievement or the deployment of desired technologies.

28. The conceptual elements of MRPs, PIMs and Trackers are presented and discussed below, describing how departures from traditional COSR may impact utilities and their customers. The following criteria can be used to evaluate the range of PBR options in relation to their goals, outcomes, advantages and disadvantages:

- Financial Results – are financial outcomes acceptable to all parties, in relation to risks assumed?
- Operational Performance – are desired public interest goals defined, measured and reasonably, but not excessively, rewarded? Alternatively, is poor performance reasonably punished?
- Properly Aligned Incentives – are utilities encouraged to cost-effectively serve customers' diverse needs or are modifications needed to improve upon the traditional COSR model.
- Administrative Efficiency – does PBR result in efficient and transparent regulatory processes that protect the public interest in just and reasonable rates and access to quality services?

29. These criteria are applied because they reflect the most important objectives of all parties interested in changes to the regulatory framework that is applied to electric utilities. Utility management is interested in meeting the needs of shareholders, customers, and the regulator across these three criteria. The Commission and Public Counsel are responsible across all of these criteria to meet their statutory mandates, and utility customers are keenly interested in outcomes in these three areas. The necessary balancing of these diverse and often competing interests argues for careful and deliberate analysis of the desired goals and outcomes of any revised regulatory framework. Additionally, the Commission must consider meticulous design and gradual movement away from the traditional regulatory models that have achieved the needed balance historically to better ensure effectiveness.

A. Multi-Year Rate Plans

30. Multi-year Rate Plans (MRPs) are intended to avoid traditional COSR rate cases for a specified period of time, often three to five years, so as to amplify the regulatory lag incentives for utility cost control. Regulatory lag is symmetrical in its financial impact. This means that when utility management is able to reduce costs or grow revenues between rate case test years, the resulting incremental operating income is retained for the benefit of shareholders as a financial reward, until the next rate case that "captures" these effects is completed. Conversely, when costs increase or sales decline between test years, earnings "attrition" occurs and shareholders are penalized, again until the next rate case is completed. Regulatory lag can therefore be fairly considered a cost-control incentive to utility management. Frequent rate cases tend to erode regulatory lag incentives for efficiency because changes in revenues and costs are more quickly translated into rate changes. Public Counsel has generally not supported the few MRP experiments that have occurred to date in Washington. In our view, Washington's MRPs included inadequacies in the parameters of such plans that caused them to be imbalanced, to the disadvantage of ratepayers.

31. An MRP, if properly designed, can intentionally expand regulatory lag to create a larger financial incentive for cost control. A relatively long moratorium period between rate cases creates a larger regulatory lag incentive for efficiency, while also reducing the administrative costs caused by more frequent rate cases. However, MRPs should be "enforceable" because greater regulatory lag will only be experienced if utilities are not allowed to seek rate adjustments during the MRP's term. MRPs can also be useful during periods of transformational change, so as to avoid the distraction of rate cases and the difficulty in quantifying significantly changing costs and business conditions within rate cases, such as when major new programmatic systems or initiatives are undertaken. Of course, it is essential that any MRP not provide excessive attrition relief, when combined with new revenues arising from customer additions, and that some of the efficiency gains stimulated by the MRP be effectively shared with ratepayers during the term of the MRP and thereafter.

32. MRPs are intended to expand upon the cost control incentive produced by regulatory lag. The following table illustrates the importance of regulatory lag as an incentive, by estimating the percentage of cumulative net changes in costs, either favorable or unfavorable, that would be absorbed by shareholders if we assume traditional COSR rates cases occur annually, triennially or employing a five-year rate case cycles.

Table 1

Year	Net Cost Change	Assumed Cumulative Net Cost Change	Cost Change Absorbed By Shareholders - Annual Rate Cases	Cost Change Absorbed By Shareholders - Triennial Rate Cases	Cost Change Absorbed By Shareholders - Five Year Rate Cycle
1	100	100	100	100	100
2	100	200	100	200	200
3	100	300	100	300	300
4	100	400	100	100	400
5	100	500	100	200	500
6	100	600	100	300	100
7	100	700	100	100	200
8	100	800	100	200	300
9	100	900	100	300	400
10	100	1000	100	100	500
Total Cost Change		5500	1000	1900	3000
Percentage of Total			18%	35%	55%

33. Clearly shareholders have more "skin in the game" with respect to cost control and the quest for productivity gains when adopting the longer rate case intervals as part of an MRP. Common MRPs have a term ranging from three to five years and often terminate with a scheduled rate case-like examination of then current financial and operating conditions to provide a foundation for a "next" MRP or a transition back to more traditional COSR regulation.

34. Available research suggests that utility cost control tends to improve under MRP regulation, in comparison to traditional and more frequent rate cases. A study released in July of

2017[12] discusses six case studies of utilities operating under MRPs. This research effort focused upon multifactor productivity growth trends and noted that the multifactor productivity growth was more rapid for utilities that operated for many years without rate cases, due to MRPs or other circumstances. Among the conclusions stated in this report:

- MRPs can produce material improvements in utility performance which can slow (or predictably restrain) growth in customer bills and bolster utility earnings.
- It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design.[13]
- MRPs are well suited for addressing conditions expected in coming years, such as rising input price inflation and DER penetration and increased need for marketing flexibility. For these and other reasons, we foresee expanded use of MRPs in U.S. electric utility regulation in coming years.[14]

35. MRPs clearly expand upon utility management incentives for cost control, by amplifying regulatory lag, the period of time between rate cases when cost changes are absorbed by shareholders rather than being translated into rate case revenue requirement adjustments. Unfortunately, the design of these plans is inherently complex and contentious, given the tension

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[12] M.N. LOWRY ET AL., GRID MODERNIZATION LABORATORY CONSORTIUM, STATE PERFORMANCE-BASED REGULATION USING MULTIYEAR RATE PLANS FOR U. S. ELECTRIC UTILITIES (2017), http://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

[13] MRP parameters require determination of acceptable levels for inception rates and how much rates will change in subsequent years, which may trigger a high-stakes rate case. A reasonable basis or methodology to adjust rates year-over-year must be determined. Controversy may also arise in defining parameters intended to offset MRP inflation allowances for reasonably estimated productivity gains in each year. It may be deemed necessary to provide for exogenous factors that adjust for changes in laws/regulations or for force majeure events, requiring detailed definitions and processes. See "Design Challenges with MRPs" discussed below.

[14] M.N. LOWRY ET AL., GRID MODERNIZATION LABORATORY CONSORTIUM, STATE PERFORMANCE-BASED REGULATION USING MULTIYEAR RATE PLANS FOR U. S. ELECTRIC UTILITIES, at v (2017), http://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

between management's fiduciary duty to maximize financial results for shareholders and the compelling public interest concerns with good service and the lowest practical price.

1. Advantages and Disadvantages of Multiyear Rate Plans

36. MRPs bring significant potential benefits along with substantial risks for consideration by regulators. The benefits of conducting fewer large, costly and contentious rate cases, along with the possibility of improved utility productivity in a manner that is equitably shared with ratepayers is conceptually attractive. However, the devil lives in the details of the design features and administration of the MRP. As explained below, it is extremely difficult to design and calibrate an adequate, but not excessive, series of price adjustments for multiple future years in a manner that is equitable to both shareholders and ratepayers. The following listings are intended to summarize MRP advantages and disadvantages, relative to traditional periodic rate cases:

a. Advantages:

- Improved efficiency incentive – cost reductions retained for shareholders within term.
- Reduced rate case frequency and regulatory costs within term.
- More predictable and stable revenues and rates within term.
- With decoupling, eliminates throughput incentive.[15]

37. The advantages of MRPs are intuitively obvious, but difficult to validate and quantify. The base case under continued traditional rate cases becomes counter-factual because rate case outcomes are not available to evaluate whether customers or the utility were any "better off" after completion of the term of an MRP. Earnings monitoring and sharing can be incorporated into MRPs, providing some protection against flaws in plan design while also diminishing some of the incentives intended to be achieved through MRP regulation. Rate case moratoria are inherently attractive, but again it is impossible to know whether rate cases would have occurred

[15] Washington has achieved elimination of the throughput incentive by approving decoupling independently of MRP regulation.

in the absence of the MRP. Predictable and stable utility rates are also inherently desirable, particularly if prices are lower than would otherwise occur in the absence of the MRP.

b. Disadvantages:

- Difficulty in MRP design and advance quantification of reasonable revenue needs of the utility over multiple future years.
- Service quality, safety, and other goals may be compromised due to strengthened cost control incentives under an MRP.
- Unexpected financial outcomes – MRPs may yield excessive or inadequate earnings or reduced access to capital on reasonable terms.
- Challenges in capturing cost-reductions for customers at plan termination, due to potential gaming of rate case timing and coordination of spending surges with MRP reconsideration dates.

2. Design Challenges with MRPs

38. The revenue requirement quantification challenge arising from MRPs must be overcome in order for the plan to satisfy public interest criteria and to avoid unexpected financial and operational outcomes. MRPs are essentially multi-year forecasted rate cases, where informed judgements are employed to determine the range of acceptable revenue requirements for several future years. Information asymmetry and the utility's inherent bias toward pessimism within financial forecasts that are produced for use by regulators are the heart of this problem. Utility management controls the best information regarding utility business dynamics and cost trends, along with unequaled familiarity with utility systems and operating conditions. Regulatory staff and intervenors simply do not have the same quality of information to bring to negotiations or to use to support any litigation involved in MRP development.

39. On August 13, 2013, the National Regulatory Research Institute (NRRI) published a report titled, Future Test Years: Challenges Posted for State Utility Commissions. The Executive

Summary of this report defines future test year (FTY) and historical test year (HTY) approaches and states:

> The reader might ask why a commission should rely on anything other than an FTY, since good ratemaking requires that new rates reflect the utility's costs and sales, at least over the first several months that they are in effect. Ratemaking, after all, is prospective, and an FTY matches the test year with the effective period of new rates. Although in theory this argument seems indisputable, it ignores the reality that forecasts are susceptible to error and some costs and sales elements are inherently difficult to predict. Another factor, as this paper stresses, is that utilities would have incentives to present biased forecasts that are not always easy for commission staff and interveners to uncover. A commission would be presumptuous to assume that forecasted costs and sales are more accurate than modified HTY data accounting for "known and measurable" changes. In fact, many commissions have taken this view, which seems sensible and in line with their mandate to set "just and reasonable" rates.
>
> In sum, an environment of rising average cost does not constitute a sufficient condition for the use of an FTY. Supporters of an FTY give this false impression, which ignores the reality of utility forecasts being susceptible to bias and inherent error. Information asymmetry, which is an acute problem in public utility regulation, makes it difficult for commissions to evaluate a utility's forecasts in terms of their accuracy and objectivity.[16]

40. The bias inherent in utility forecasts prepared for regulatory use is undeniable and any reliance upon such forecasts to develop MRPs tends to amplify this bias and the risk to the public interest created by poorly developed plans. Recent experience in Washington at the conclusion of the Puget Sound Energy's MRP is instructive, where testimony by Commission Staff and Public Counsel suggested that PSE's expiring MRP produced large revenue increases and excessive earnings for the utility as a result of overly generous K-factor and revenue per customer decoupling rate increases in a period of stable costs.[17]

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[16] KEN COSTELLO, NATIONAL REGULATORY RESEARCH INSTITUTE, FUTURE TEST YEARS: CHALLENGES POSED FOR STATE UTILITY COMMISSIONS, at iv (2013), https://static1.squarespace.com/static/5aa1aa7c1137a619b8fc2e9c/t/5bc09b12c83025dd65c70b97/1539349266934/L-2012-2317273+-+Attachment+to+Initial+Position+Paper+of+IECPA+%28NRRI+Rep....pdf.

[17] Michael L. Brosch, Exh. MLB-1T at 13-26, *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170034; Thomas E. Schooley, Exh. TES-1T at 9-10, *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170034.

41. Another MRP design concern is optionality. If the utility is allowed the option to participate in an MRP without the obligation to participate, the problems with information asymmetry and forecasting bias become more acute. Management can be expected to "opt in" to an MRP only when doing so is clearly beneficial to shareholders, relative to COSR.[18] Moreover, if the utility is allowed to request traditional COSR rate relief prematurely, before the expiration of an established MRP, such optionality can undermine any ratepayer benefit intended to result from the MRP.

3. Service Quality Considerations with MRPs

42. The strengthened utility cost control incentives within MRPs can serve to encourage management to compromise service quality, safety, customer satisfaction and reduce utility investments that may be needed to further desirable public policy goals. Maintaining and improving service quality and customer satisfaction involves significant and ongoing costs. New investments in system reliability and public safety can often be deferred in the short term and operational decisions involving call center staffing, vegetation management, and a host of other operational functions can also be temporarily deferred. Indeed, PSE argued in a recent rate case that it needed special cost recovery surcharge authority in order to invest needed Electric Reliability Plan funding, after completing its negotiated MRP and presenting a COSR rate case.[19] Cost controls strengthened during an MRP would tend to encourage utility management to defer discretionary expenditures, to a point that could unreasonably compromise service resilience and reliability. The ability to defer costs in the short term, without suffering immediate service deterioration impacts, can also invite gaming of the rate case cycle, where costs are

[18] Engrossed Substitute House Bill 2839 contained such optionality in New Section 4 at paragraph (4). Paragraph (6) appears to provide for rescission or modification of an AFOR but only"in the manner requested by the electrical or gas company." ESHB 2839, 65th Leg., Reg. Sess., at 10:5-10, 10:20-24 (2018), http://lawfilesext.leg.wa.gov/biennium/2017-18/Pdf/Bills/House%20Bills/2839-S.E.pdf.

[19] Puget's requested ECRM was not included in the non-unanimous stipulation approved in Docket 170033. *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170034, Order 08: Final Order, ¶ 317 (Dec. 5, 2017).

deferred for several years and then concentrated within test years to maximize recovery of such higher costs.

43. Performance Incentive Mechanisms (PIMs) are addressed in the next section of this report and can be employed along with an MRP to monitor and encourage desired service quality and other public policy outcomes during the term of an MRP.

4. Unexpected MRP Financial Outcomes

44. Multi-year rate plans necessarily involve advance estimation of the utility's financial needs over multiple future time periods.[20] Many of the required assumptions about future financial needs are highly uncertain and are driven by externalities beyond the control of utility management, including future rates of inflation, wage cost trends, market interest rates, demand levels, changes in environmental regulations, weather conditions, storms, changes in tax laws and regulations and new regulatory mandates. Of course, financial needs are increasingly uncertain the further into the future one is attempting to design an MRP. Additionally, as noted above, utility management has a strong incentive to adopt relatively pessimistic assumptions around these uncertainties within any financial forecasts intended to be used by regulators to determine revenue and profit levels well into the future. These forecasting concerns cause substantial risk that actual financial performance will depart from expectations during the term of an MRP.

45. Utilities maintain long-term financial models to guide decisions made regarding capital investment plans, the timing of regulatory initiatives and financing programs, staffing plans and a multitude of other internal management functions. These financial models are routinely iterated to evaluate changing business conditions and to evaluate potential outcomes from proposed

[20] The simplest form of MRP is the rate care "moratorium" arrangement, where the parties to a rate case, merger or other type of regulatory proceeding may agree to not file for rate relief for a defined future time period. These agreements may not be enforceable if challenged or may include force majeure terms enabling the parties to avoid the moratorium restriction under defined conditions.

legislation or regulatory proceedings, where revenue and cost-recovery issues are significant. Regulators are often unable to independently replicate and defend comparably sophisticated and informed financial modeling capabilities and, thus, may become dependent upon the long-term forecasts prepared by utility management when developing multi-year rate plans. This is a less than ideal dependency, given the judgment involved in such forecasting and the inherent bias that is introduced into the process.

46. At one extreme, the MRP may yield much stronger earnings and cash flow than was forecasted and expected at the inception of the plan. While desirable from the perspective of shareholders in the short term, this outcome contributes to negative public interest impressions upon review of the MRP and may encourage the regulator to revert to traditional COSR to remedy "excessive earnings." If the MRP is scheduled to expire or be updated at a known future date, the utility's discretionary spending can be concentrated around that date to game the process to benefit shareholders. Absent a mechanism to capture cost savings that were incented and ultimately achieved during the MRP term, ratepayers may realize very little of the operational efficiency advantages intended to result from the plan because such efficiencies are left on the table in plan design or at the time of plan review.

47. At the other extreme, the MRP may produce much weaker earnings and cash flow than was anticipated at the inception of the plan. This result could occur because of improper specification of price adjustment indices, overly ambitious productivity goals or a confluence of negative outcomes around the uncontrollable externalities faced by the business. This outcome may be viewed as favorable to customers in the short term, but may lead to credit rating deterioration, higher financing costs, and assertions of an urgent need for early plan termination or, at least, major adjustment of MRP parameters.

48. MRPs can be designed with features to mitigate unexpected financial outcomes. Earnings monitoring and sharing can be employed to track and react to undesirable financial outcomes, either with exit ramps or mid-course corrections at certain financial triggers or by "sharing" excursions around targeted earnings levels. Management's superior access to financial planning data and models and the inherent bias toward pessimistic assumptions may argue for asymmetrical earnings sharing, where only "excess" earnings are considered and returned to customers.[21]

B. Performance Incentive Measures

49. A more targeted PBR approach involves the definition of Performance Incentive Measures (PIMs) that identify useful metrics and then measure and compare actual utility performance against established performance goals. PIMs can be implemented independently, or combined with an MRP, to provide more targeted performance rewards and penalties that complement the broad cost control incentive provided by the MRP. PIMs can be defined and applied for any number of performance outcomes across a range of utility performance areas, such as:

Table 2

Performance Incentive Measure Examples		
Issue Addressed	***Purpose***	***Possible Metrics***
Safety	Employee and Public Risk Management	Accident Reports, Lost Work Time, OSHA Incidents
Reliability	Reduce Service Outages, Power Quality	SAIDI, SAIFI, MAIFI, CAIDI
Efficiency	Cost control and Productivity Improvement	Generation EAF, EFOR, Cost per Customer/KWH, Unit Cost vs Peers, Energy Loss %

[21] As noted above, earnings monitoring and sharing may be viewed as essential public interest features of any MRP, even though intended incentives may be diminished when excessive earnings resulting from cost control measures must be shared with customers.

Customer Access	Call Center and Service Call Responsiveness, Program Access	Call Answer Time, Abandoned Call Rates, Appointments Met, Program Participation, Meters Read %, Customer Complaints
Resilience	Restoration of Outages, Avoidance of Outages	Outage Restore Intervals, Vegetation Management, System Hardening, Worst Perf Circuits, Emergency Response Times
Affordability	Stable and Reasonable Prices	Price trends vs. Index, Level Pay Plan Participation, Assistance/Low Income Access
Public Policy	Progress on Renewable, Energy Efficiency, Demand Response, Environmental Targets	EE Program Participation, DER Interconnections/Intervals, RPS progress, Program Participation, Compliance Tracking

50. PIMs are designed to track actual performance against established targets or goals within selected performance issue areas. Metrics are defined for each PIM that rely upon statistical data that can are standardized and tracked to evaluate achieved performance relative to targets or trends. For example, commonly employed electric distribution system reliability metrics include System Average Interruption Duration/Frequency statistics that have common definitions and are reported throughout the industry, to facilitate utility trend and peer analysis as well as establish of targets based upon averages, trends, and/or peer performance.

51. It is not difficult to gain acceptance for PIMs that track and report actual performance relative to historical company trends or industry averages. PIMs can be publicly reported and made available on utility web sites to help hold the utility accountable for performance. This reported data can then be relied upon in regulatory proceedings to temper Commission judgments around customer complaints, public hearing issues, and even deliberation and determination of the allowed return on equity.

52. However, when PIMs are monetized with financial incentives or penalties, complexity grows significantly because of the difficulty in reasonably defining performance benchmarks or targets and then calibrating appropriate reward and/or penalty amounts to reasonably stimulate but not over-compensate for desired performance. Monetized PIMs tie financial rewards or penalties to variations in the utility' actual performance metrics against established benchmarks or targets. It is essential that such rewards and penalties be carefully calibrated in order to provide just enough, but not excessive financial incentive to encourage desired performance levels at reasonable cost. Improperly calibrated PIM incentives can reward the utility repeatedly or excessively, or pay rewards for outcomes that would have occurred naturally, without management effort or action. Alternatively, PIM incentives that are not sufficiently compensatory may prove inadequate to encourage management to incur the costs or take the risks needed to achieve reasonable performance. Since incremental improvements in performance often involve exponential levels of new costs, the challenge in PIM design is to first determine how much performance is optimal, relative to the costs of achievement, and then to design incentives that are calibrated to induce achievement at that level.

53. As always, details are crucial with PIMs. The importance of the definition and calibration of PIMs may require detailed cost/benefit analysis, continuous review of PIM results, and incremental adjustments to initially determined PIM incentives, to allow the regulator to monitor and improve performance at reasonable cost. PIMs must carefully define metrics and performance targets, and then rigorously calibrate and enforce incentive and penalties to avoid contentious administrative disputes or litigation as well as potential gaming and manipulation by utilities, who control the data and prepare the administrative filings required to administer the PIMs.

54. As noted above, PIMs can be employed as part of multi-year rate plans (MRPs), to counteract the potential for service quality degradation caused by heightened incentives for cost-

control during the term of the MRP. In this context, an AFOR plan could bundle an MRP with a series of monetized PIMs so that service quality is rewarded as much as cost reductions, where the PIM incentives are large enough to justify not reducing costs where service quality deterioration may occur.

C. Preferential Cost Recovery (Trackers)

55. Existing regulation in Washington and most other states incorporates the use of cost recovery mechanisms or cost "trackers" between rate case test years. Trackers first became popular in the 1970s when electric and gas utilities were first exposed to fuel price volatility that threatened financial stability in the absence of timely rate adjustments needed to pass-through fuel cost changes outside of rate cases. Since then, a wide variety of cost tracking tariffs, cost deferral accounting mechanisms, surcharges and other cost recovery devices have been installed to provide preferential cost recovery outside of traditional rate cases.

56. The most common form of preferential cost recovery mechanism remains the fuel/energy cost recovery clause for electric and gas utilities, where purchased fuel/energy costs have several attributes that have historically justified such exceptional regulatory treatment. Fuel and purchased energy costs tend to be:

- Significant in relation to the utility's overall cost of service,
- Volatile in nature, contributing to financial instability if not "tracked," and
- Driven by market forces that are not controllable by utility management.

57. Cost recovery trackers have become more commonplace, as new public policy goals contributed to the expansion beyond these traditional criteria that were initially used to rationalize tracking of fuel and energy costs. For example, the expansion of utility administered energy efficiency programs was often encouraged by granting regulatory permission to rapidly recover incremental program costs and lost sales margins through rate surcharges. To further encourage utility support of energy efficiency programs, decoupling mechanisms were approved in several states to provide preferential rate recovery for either the lost sales margins caused by energy efficiency programs or to fully track changes in utility sales and revenues. Examples of preferential utility cost tracking mechanisms that have been employed in one or more states include the following:

Table 3

Preferential Cost Recovery Examples		
Cost Change Addressed	***Purpose***	***Mechanism Employed***
Fuel/Purchased Energy	Rapidly adjust rates to track changes in large and volatile costs not controllable by management	Tariff Surcharges & Reconciliations; Deferral Accounting
Energy Efficiency Program Costs	Encourage adequate funding of EE programs overseen by regulators	Tariff Surcharges & Reconciliations; Deferral Accounting
Programmatic Infrastructure Replacement	Encourage rapid replacement of failing types of facilities	Tariff Surcharges & Reconciliations; Deferral Accounting
Sales Volume Fluctuations Decoupling	Remove Throughput Incentive; Encourage DER and DR Measures	Deferral Accounting, Periodic Rate Adjustments
Storm Restoration Cost	Encourage Rapid Restoration of Outages	Deferral Accounting, Periodic Rate Adjustments
Pension/OPEB Costs	Address benefit plan cost variations caused by actuarial assumptions	Deferral Accounting, Periodic Rate Adjustments

58. Preferential cost recovery approaches are controversial by their nature, where piecemeal regulation is often proposed by a party attempting to achieve financial advantage from the selective use of a new mechanism to grow revenues. For example, you rarely see full revenue decoupling proposed by a utility that is experiencing increasing sales volumes because such a mechanism would produce reduced earnings for the utility, compared to traditional regulation (without decoupling) where sales gains between test years are earnings accretive. Regulators have seen cost tracking proposals from utilities targeting wide variety of isolated costs including certain taxes, bad debts, environmental programs, transmission fees, government mandates, and other generally increasing types of costs; usually ignoring potentially offsetting cost savings in other areas.

59. The design and administration of preferential cost recovery mechanisms can be controversial at the inception of the mechanism and complex in administration. The definition of precisely what costs can be "tracked" outside of rate cases can lead to the gaming of accounting classifications and produce a bias favoring the incurrence of tracked costs between base rate cases, even when the more efficient overall solution may be to incur non-tracked costs. For example, management is not encouraged to invest in fuel saving technology or more frequent or comprehensive power plant overhauls when the primary result is lower fuel expense that is simply passed through an adjustment clause to ratepayers. On this point, the mere existence of a fuel adjustment mechanism is believed by some to encourage utility reluctance to interconnect and rely upon more renewable resources where variable costs do not receive preferential regulatory treatment.

60. Preferential cost recovery mechanisms will likely continue to be part of any PBR mechanism because certain costs incurred by the utility will continue to be so large, volatile, and uncontrollable as to require tracking in the interest of financial stability. Moreover, the public policy goals that justified preferential cost recovery for Energy Efficiency, Demand Response, or other desirable programs may not be addressed adequately within a PBR plan without continued tracking. As always, the challenge will be finding the appropriate balance between public policy objectives and consumer interests in affordable utility services and total energy bills.

61. Washington's current regulatory scheme includes a number of cost trackers, including fuel cost recovery and critical natural gas infrastructure recovery. As earlier mentioned in these comments, PSE recently proposed an electric infrastructure cost recovery mechanism. This proposal was rejected by the Commission because electric infrastructure replacements do not involve the same kind of public safety demands (i.e. a failing gas main could result in leaks if it is not quickly replaced).[22]

VI. RESPONSE TO OTHER PARTIES

62. Public Counsel participated in the December 10, 2018, Workshop where the utilities and several other stakeholders spoke generally about their concerns and recommendations in this investigatory docket. It is assumed that a more formal and complete statement of the stakeholders' priority goals and recommendations will appear within Comments filed contemporaneously with this submission. Therefore, Public Counsel offers a limited and general response to several workshop topics, without attributing any particular concern or recommendation to another party prior to the receipt of filed comments. As noted herein, Public Counsel recommends offering all stakeholders an opportunity to respond formally to filed Comments in the interest of a more complete record in this proceeding.

63. <u>Expedited COSR procedures</u> that appear to be supported by certain of Washington's utilities would further reduce regulatory lag and amplify the concerns stated above with respect to traditional COSR, where higher costs are quickly rewarded with higher revenues. More rapid rate case processing in the form of Expedited Rate Filings or selective projections of increasing costs in rate cases represents movement in the wrong direction, which is inconsistent with the affordability and cost control goals described above. Public Counsel supports evolutionary

[22] *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170034, Order 08: Final Order, ¶ 327 (Dec. 5, 2017).

movement toward PBR in a measured and controlled manner, not regressive changes that further embed traditional regulatory methods without, importantly, offering the benefits of the traditional regulatory framework. There has been no demonstration of financial need for expedited traditional COSR approaches. Indeed, the electric utilities in Washington are generally performing very well, based upon their filed Commission Basis Reports of earned returns.[23]

64. Capital Expenditure (CAPEX) Bias resulting from the linkage between rate base growth and higher utility earnings was also mentioned by at least one of the stakeholders in the Workshop. This is a real concern under traditional COSR regulation, where the primary opportunity for the utility to grow and increase earnings is by making new Plant in Service investments that are includable in rate base. MRP approaches can mitigate the CAPEX bias by subjecting all costs, whether expensed or capital in nature, to more extensive regulatory lag.

65. Open-ended policy changes were encouraged in the Workshop by certain stakeholders. Under this approach, the utilities would be free to make future filings requesting alternative regulation mechanisms, with no specific conditions or criteria applied other than a broad public interest standard in just and reasonable rates. This approach would guarantee Commission consideration of only changes to existing regulatory mechanisms that are beneficial to utility shareholder interests, rather than a more balanced and equitable approach where the details of reformed regulation are worked out in advance, with adequate opportunity for stakeholders to be involved in the detailed analysis and design of each change before implementation. The Commission should not adopt any vague and permissive policy inviting utilities to recommend creative new regulatory mechanisms within future proceedings. Instead, a careful and deliberate assessment of each of the existing regulatory mechanisms should be undertaken to see what specific changes are actually needed. Then, a series of workshops, discovery, testimony, briefs,

[23] *See supra* p. 10 note 10.

and formal analyses within the record should be relied upon to carefully prescribe changes to regulatory mechanisms that are tailored to the circumstances of each utility.

VII. PROCEDURAL RECOMMENDATIONS

66. The scope of potential changes to Washington's regulatory framework in the pending docket is not yet clearly defined. Because of the importance of utility regulation to all stakeholders, Public Counsel recommends that the procedural process employed by the Commission in this docket be both comprehensive and inclusive, providing all parties with detailed notice of changes that are contemplated and an opportunity to affirmatively recommend specific changes and also to comment in response to the recommendations of others. To this end, the pending activities of another state commission working on reformed regulation may be instructive.

67. Public Counsel is aware of an ongoing comprehensive investigation of Performance Based Regulation initiated by the Hawaii Public Utilities Commission (HPUC) in April 2018. If substantive changes to the regulatory framework in Washington are contemplated, the Commission may find merit in adopting some of Hawaii's approach within a similar investigative docket. As noted above, Hawaii's circumstances provide heightened urgency for regulatory change. A 100 percent RPS standard by 2045, intensive penetration of DER facilities, high utility rates that encourage energy efficiency and DER deployment, and a series of legal imperatives are driving regulatory reform in Hawaii. HPUC Order No. 35411 describes the rationale for the HPUC's investigation, stating the following in introductory comments:

> Hawaii's electric power industry is in the midst of a significant transition from predominantly centralized fossil-fuel-based generation systems towards increasingly distributed and renewable generation systems. This transition includes the incorporation of large amounts of variable renewable generation resources, distributed energy resources ("DER") including demand response resources, and a considerable focus on enhancing customer choice. The State of Hawaii is committed to supporting this transition, and has adopted several laws and policies

> requiring reductions in fossil-fuel use and greenhouse gas emissions, including a Renewable Portfolio Standard ("RPS") goal of 100% by the year 2045.
>
> In response to this dynamic and evolving landscape, the State's electric utilities are undertaking substantial efforts to adapt system operations, engineering, and planning. These adaptations, in turn, are evolving the role of the electric utility in certain respects, including the type of operations and services provided, the proportion of utility-owned versus contracted-for generation resources, and the nature of the utilities' relationship with customers.
>
> The commission has acknowledged that the factors driving this energy transition are of sufficient breadth and magnitude that Hawaii's regulatory framework must also continue to evolve to enable the State's electric utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and result in affordable rates.
>
> PBR enables regulators to reform legacy regulatory structures to enable innovations within modern power systems. An old regulatory paradigm built to ensure safe and reliable electricity at reasonable prices from capital-intensive electricity monopolies is now adjusting to a new era of disruptive technological advances that change the way utilities make money and what value customers expect from their own electricity company.
>
> PBR attempts to address some of the issues and disincentives inherent in traditional cost-of service regulation ("COSR") through a set of alternative regulatory mechanisms intended to focus utilities on performance and alignment with public policy goals, as opposed to growth in capital investments or other traditional determinants of utility earnings under COSR.
>
> Well-designed PBR frameworks should result in an incentive structure that encourages exemplary utility performance irrespective of the nature of its investments (e.g., investment in capital expenditures verses investment in efficiency measures). By providing rewards for specific outcomes and objectives, a PBR framework should provide a utility with the opportunity to earn fair compensation, based on a business model that is well aligned with the public interest. As demonstrated by experience in other jurisdictions, PBR can provide a variety of benefits, including; advancing regulatory goals; providing utilities with increased flexibility, opportunity, and accountability to pursue identified goals; and freeing up limited regulatory resources to focus on overseeing utility success in achieving public priorities.[24]

68. The HPUC's investigation is scheduled to occur over a nearly two-year period and has been undertaken in two phases. Phase 1 is presently underway and is structured as an "Evaluation and Assessment" of the current regulatory framework to determine "which

[24] *Public Utilities Commission Instituting a Proceeding to Investigate Performance-Based Regulation*, Docket No. 2018-0088, Order No. 35411, at 1-4 (Haw. Pub. Util. Comm'n Apr. 18, 2018) (footnotes omitted).

components are aligned with customer interests and functioning as intended and which are not, with the goal of identifying specific mechanisms that require modification/refinement, as well as specific areas of utility performance that should be addressed further." Order No. 35411 states that "[u]pon review of the Phase 1 record, the commission anticipates issuing an order that further distills the issues, focusing the Parties' efforts on specific regulatory mechanisms and areas of utility performance to be addressed in Phase 2."[25]

69. The Hawaii PUC expects Phase 2 will be directed toward "Design and Implementation" efforts that will consume approximately twelve months. This later phase is described as "[h]aving identified the specific areas of utility performance that should be improved, as well as the attendant metrics for measuring successful outcomes in those areas. Phase 2 will focus on refinement and/or modifications to the existing regulatory framework that will incent the utility to achieve those outcomes."[26]

70. Thus far in Phase 1 of the HPUC investigation, that Commission Staff has issued three "Concept Papers to Support Docket Activities" that were captioned:

- Goals and Outcomes for Performance-Based Regulation in Hawaii,
- Assessing the Existing Regulatory Framework in Hawaii, and
- Prioritized Outcomes, Regulatory Options, and Metric Development for PBR in Hawaii.

71. After issuance of each Concept Paper, a workshop was convened by the Commission in Honolulu to receive presentations and feedback from all stakeholders. After each workshop, an opportunity to file a Brief was provided to each party, so as to develop a complete record to support the anticipated HPUC Order concluding Phase 1. The last round of Briefs from the

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[25] *Public Utilities Commission Instituting a Proceeding to Investigate Performance-Based Regulation*, Docket No. 2018-0088, Order No. 35411, at 53-55 (Haw. Pub. Util. Comm'n Apr. 18, 2018). The HPUC indicated that it "expects Phase 1 to conclude in approximately nine months."

[26] *Id.* at 55.

parties were filed with the HPUC on January 4, 2019, and a Phase 1 Order is expected in the near future.[27]

72. Of course, the dynamics of Hawaii's current generation resources, geography, and climate are much different than what Washington utilities deal with. As such, the substantive recommendations made by the HPUC may be different than what might occur in Washington. Regardless, Hawaii's proceeding was initiated for many of the same reasons Washington stakeholders are at the table in this Docket. As such, the process followed by HPUC and stakeholders can serve as a model for the WUTC in order to ensure robust stakeholder participation and a complete record from which the Commission can work.

VIII. CONCLUSION

73. Public Counsel welcomes and encourages the Commission's investigation into the state of the current regulatory framework. The regulatory framework employed by the Commission in its regulatory oversight of utilities significantly impacts all stakeholders, and ensuring that the framework adequately balances the stakeholder interests is of critical importance. The existing regulatory framework in Washington has evolved gradually over many years and already incorporates significant departures from traditional COSR to meet changing circumstances and emerging public interest priorities. It is essential that the Commission's investigation be methodical and deliberate, with sufficient procedural steps to ensure that each new change under consideration is:

- Responsive to proven deficiencies in existing regulatory mechanisms based upon factual evidence.

[27] Filed documents in Docket No. 2018-0088 are available by entering "2018-0088" within the "Docket No." box at https://dms.puc.hawaii.gov/dms/dockets?action=loadAdvSearch and then selecting the "documents" tab.

- Reasonably expected to better achieve identified priority goals within the Commission's authority than existing regulatory mechanisms.
- Balanced with respect to shareholder, ratepayer, and broader public interests.
- Carefully tailored and calibrated to the specific circumstances of each utility with sufficient consumer and shareholder safeguards.
- Subject to continuing review and regulatory oversight to protect against unanticipated outcomes.

74. Public Counsel recommends a comprehensive procedural schedule for the planned investigation that is systematic, transparent and considers the input of all stakeholders. To that end, the investigative process underway in Hawaii is referenced to illustrate an approach that could prove useful in Washington. We welcome the opportunity to participate in such a process.

75. Dated this 17th day of January 2019.

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