EXH. RJB-1T
DOCKETS UE-220066/UG-220067
2022 PSE GENERAL RATE CASE
WITNESS: RONALD J. BINZ

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-220066** **Docket UG-220067**

PREFILED RESPONSE TESTIMONY (NONCONFIDENTIAL) OF

RONALD J. BINZ

ON BEHALF OF NW ENERGY COALITION, FRONT AND CENTERED, AND SIERRA CLUB

JULY 28, 2022

NW ENERGY COALITION, FRONT AND CENTERED, AND SIERRA CLUB

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INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Ronald J. Binz. I am a Principal with Public Policy Consulting, a firm specializing in energy policy and regulatory matters. I provide consulting services to a variety of public sector and private sector clients in the energy industries, primarily in the regulatory arena. My business address is 333 Eudora Street, Denver, Colorado, 80220.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of NW Energy Coalition ("NWEC"), Front and Centered, and Sierra Club (collectively referred to in this testimony as the "Joint Environmental Advocates").

Q. Please summarize your qualifications and work experience.

A. I have been involved in energy regulation since 1979. From 1995 to 2006, and from 2011 to the present, I have served as principal of Public Policy Consulting, where I provide consulting services on regulation in the energy and telecommunications markets. My focus in recent years has been on performance-based regulation and energy regulatory policy, including Integrated Resource Planning, clean technology, smart grid, and climate issues.

From 2007 to 2011, I was Chairman of the Colorado Public Utilities Commission ("PUC"). In that capacity, I helped implement Colorado's vision for a "New Energy Economy" and its 30% Renewable Energy Portfolio Standard, participated in the Governor's Climate Action Plan, rewrote the Commission's Integrated Resource Planning rules, streamlined telecommunications regulation, promoted broadband telecommunications investment, and improved the Commission's operations.

As Commission Chair, I presided over implementation of the Colorado Clean Air-

Clean Jobs Act, examining proposals of electric utilities to reduce pollutants from their fleets of coal fired power plants.

I also presided over the modification and approval of an electric utility resource plan involving the addition of substantial amounts of new wind capacity, the early closure of two coal power plants to reduce carbon and other emissions and substantial amounts of new energy efficiency savings.

From July 2011 to July 2013, I was Senior Policy Advisor at the Center for the New Energy Economy at Colorado State University, which provides policymakers, governors, regulators, and other decision-makers with a roadmap to accelerate the nationwide development of a new energy economy.

From 1977 to date, I have participated in more than 150 regulatory proceedings before the Federal Energy Regulatory Commission ("FERC"), the Federal Communications Commission ("FCC"), State and Federal District Courts, the 8th Circuit, 10th Circuit and D.C. Circuit Courts of Appeal, the U.S. Supreme Court, and state regulatory commissions in California, Colorado, Georgia, Hawaii, Idaho, Maine, Massachusetts, Missouri, Montana, New York, North Dakota, Rhode Island, South Dakota, Texas, Utah, Washington, Wyoming, and the District of Columbia. I have filed testimony in at least sixty proceedings before these bodies, addressing technical and policy issues in electricity, natural gas, telecommunications, and water regulation. I have also testified before U.S. House and Senate Committees sixteen times.

From 1996-2003, I served as President and Policy Director of the Competition Policy Institute, an independent non-profit organization based in Washington, DC, advocating for state and federal policies to bring competition to energy and telecommunications markets for consumers' benefit.

From 1984 to 1995, I was director of the Colorado Office of Consumer Counsel, Colorado's state-funded utility consumer advocate office. During my tenure, the office was a party to more than two hundred legal cases before the Colorado PUC, FERC, FCC, and the courts. I negotiated rate settlement agreements with utilities, regularly testified before the Colorado general assembly, and presented to professional business and consumer organizations on utility rate matters.

My educational background includes an M.A. degree in Mathematics from the University of Colorado (1977), course requirements met for Ph.D., graduate coursework toward an M.A. in Economics from the University of Colorado (1981-1984), and a B.A. with Honors in Philosophy from St. Louis University (1971).

I have authored or co-authored numerous publications on energy and regulatory matters, including *Risk-aware Planning and a New Model for the Utility-Regulator Relationship* (July 2012).[1] A copy of my professional resume, which includes my employment history, education, Congressional testimony, regulatory testimony, reports and publications, and professional associations and activities, is attached to this testimony as Exh. RJB-2.

Q. Have you previously testified before the Washington Utilities and Transportation Commission ("UTC" or the "Commission")?

A. Yes. I filed testimony in Docket No. UE-200115, concerning the sale of Puget Sound Energy's interests in Colstrip Unit 4. The case was withdrawn before hearing.

[1] Binz, R.J. and D. Mullen, July 2012, *Risk-Aware Planning, and a New Model for the Utility-Regulator Relationship*. Available at: http://www.rbinz.com/Binz%20Marritz%20Paper%20071812.pdf.

Q. What is the purpose of your testimony?

A. The Joint Environmental Advocates asked me to review the 3-year multi-year rate plan (MYRP) filed by Puget Sound Energy ("PSE") and to offer recommendations to the Commission.

SUMMARY OF FINDINGS AND CONCLUSIONS

Q. Please summarize the conclusions and recommendations stemming from your review of PSE's Performance-Based Regulation ("PBR") proposal.

A. My conclusions are as follows:

1. Fundamental changes in the energy sector and pressing environmental concerns require utilities to change how they operate and how they are regulated. Simply put, traditional cost-of-service regulation ("COSR") is no longer adequate to the task of achieving the outcomes desired of public policy.
2. While PSE's PBR filing comports with the new statute, it is excessively timid and fails to incorporate the beneficial features that PBR commonly offers. PSE's proposal is indistinguishable from three successive rate cases transacted at the beginning of a three-year period.
3. Due to the limitations of PSE's PBR filing, I recommend that the Commission either reject the plan or limit its effect to one year.
4. The Commission should specify in this case the ingredients to be included in the next PBR plan for UTC consideration.
5. The Commission should use the future PBR proceeding to explore alternatives to cost of service regulation, such as revenue cap regulation.

Q. If the Commission adopts PSE's PBR proposal in whole or in part, what changes would you recommend?

A. The Commission should require PSE to revise its proposed PIMs in line with the testimony of Joint Environmental Advocates witnesses Amy Wheeless and Ed Burgess.

TESTIMONY

Q. What is Performance-Based Regulation and why should the UTC pursue PBR?

A. "All regulation is incentive regulation."[2] With this quip, former Maine and New York utilities Commissioner Peter Bradford meant that all methods of regulation provide incentives, whether explicit or not, that affect the behavior of utilities. In some sense, the regulator's most important job is to choose among styles of regulation and the various possible incentives presented by each style.

The new realities of the electric power sector, including the proliferation of distributed energy resources ("DERs") and the urgent need to eliminate carbon pollution, mean that utilities must modify their traditional business model. For that reason, utilities should be regulated in a way that enables the transition to a revised business model.

Q. How could Performance-Based Regulation better incentivize rapid adoption of clean energy resources in an equitable manner?

A. Simply stated, PBR allows regulation to integrate objectives (outcomes) into the fabric of regulation. To do this, PBR removes systemic biases and undesirable incentives from standard cost-of-service regulation. This permits regulators to move forward on selected outcomes, while simultaneously rewarding utilities for their achievement, making the

[2] RAP 2017 at 1 (citing Bradford, P. (1989). Incentive Regulation from a State Commission Perspective. Remarks to the Chief Executive's Forum).

utility's compensation much more connected to a utility's performance. If, for example, regulation can remove the "capital bias" engendered by standard cost-of-service regulation, the utility will give the correct assessment for DERs. In sum, PBR can fundamentally change the incentives under which utilities operate in the standard cost-of-service mode. Among other outcomes, PBR, if successfully implemented, could cause Washington utilities to achieve CETA's outcomes more efficiently, affordably, and more equitably, while delivering greater benefits to customers than business-as-usual. Starting on page 10 below, I discuss the key elements needed to ensure successful implementation of PBR.

Shortcomings of Cost-of-Service Regulation

Q. What are the incentives of cost-of-service regulation as it is typically practiced?

A. Regulated utilities have historically operated under the cost-of-service regulation model, under which a utility's costs are repaid and its profit is determined based mostly on the size of the utility's capital investments. However,

> The shortcomings of traditional COSR in providing electric utilities with incentives that are aligned with certain regulatory goals are becoming increasingly clear. In particular, COSR can provide strong incentives to increase electricity sales and utility rate base.[3]

This quotation is from a paper that Dr. Mark Lowry and former Massachusetts Commissioner Tim Woolf presented at a conference at Lawrence Berkeley National Laboratory in 2016. As I will discuss later, while the predicates apply to PSE, Dr. Lowry does not recommend the solutions outlined in the paper, which is attached as Exh. RJB-3.

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[3] Lowry, M., and T. Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future,* Future Electric Utility Regulation series, Lawrence Berkeley National Laboratory, LBNL-1004130 at 13 (2016) (Exh. RJB-3).

Q. Please describe some of the shortcomings of cost-of-service regulation.

A. I will describe five categories of shortcomings.

First, utilities regulated under COSR have a "**capex (capital expense) bias**." Capex growth is the main source of revenue growth for utilities regulated under rate-base rate-of-return ("RBRR") regulation. For that reason, utilities will prefer to address a need on the electric grid through capital investment, in contrast to non-rate based approaches such as employing a "non-wires alternative,"[4] purchasing services from others, or allowing DER providers to address the need. Similarly, utilities prefer to own generation facilities, in contrast to purchasing capacity and energy from independent power producers. The structures of COSR and RBRR make these preferences obvious, and utilities are logical to respond to the incentives.

Next, utilities regulated under COSR have a "**throughput incentive**" since increased sales mean increased revenues. Regulators know well the difficulties of inducing utilities to undertake energy efficiency or demand response programs. Even though energy efficiency is usually the least-cost approach to creating new capacity, it collides with the utilities' desire to increase (or at least maintain) sales levels.[5] The Commission knows that this tendency can be partially offset by using revenue decoupling, in which a utility's revenues are decoupled from its sales. Decoupling dampens the throughput incentive, but may or may not be sufficient to cause the utility to embrace energy efficiency. Further, the Commission may

[4] Non-wires alternatives ("NWA") are electric utility system investments and operating practices that can defer or replace the need for specific transmission or distribution projects, at lower total cost. NWAs accomplish this by reducing transmission congestion or distribution system constraints at times of peak demand in specific grid areas.

[5] Dr. Lowry agrees: "In addition, utilities have a financial disincentive to implement DR programs, as they tend to reduce billing determinants, rate base and earnings." Exh. MNL-1T, p. 31 at 13-15.

need to consider modernizing the existing decoupling mechanism to accommodate the desire for beneficial electrification, which will grow total electric consumption.

Third, COSR provides, at best, only **weak incentives to improve firm efficiency**. To begin, utilities are recompensed for their prudent operating expenses under a system that is sometimes derided as "cost-plus." Next, a large fraction of a utility's costs is related to generation fuels and purchased power. Special "passthrough" mechanisms ensure that these costs are reimbursed in an "automatic" manner, usually within a month of incurrence. In obvious fashion, these passthrough mechanisms reduce pressure on utility earnings, reducing further what used to be counted on as a spur to firm efficiency: regulatory lag.

Supporters of COSR argue that, between rate cases, a utility faces some pressure towards efficiency since it cannot increase rates without filing an application with the regulator. Assuming this pressure exists as described, it is mitigated significantly by passthrough mechanisms, by requirements for regular rate cases, and by "earnings sharing mechanisms" that reduce earnings in excess of authorized and sometimes increase earnings when they are sufficiently below the authorized levels.

Fourth, standard COSR has **no mechanism** to induce utilities to accomplish important **public policy goals** such as superior customer service, decarbonization, economic deployment of DERs, beneficial electrification (*e.g.* buildings and electric vehicles), etc. The Commission may identify additional public policy preferences. Stated succinctly, COSR does not promote, and may discourage, certain desirable outcomes. This failure led to a complete makeover of regulation in the United Kingdom, moving to an outcome-oriented regulatory scheme called RIIO.[6]

Finally, another, if subtle, difference between COSR and performance-based regulation is captured in the following formulation. It expresses two different visions of what economic regulation seeks to accomplish:

COSR: Are we paying the right amount for what the utility provided?

vs.

PBR: Are we getting enough for our payment to the utility?

Cost-of-service regulation tends to focus heavily on utility costs, earned return, and cost of capital. Performance-based regulation tends to focus on a utility's performance and desired outcomes while providing the utility the ability to earn a corresponding earnings level.

Q. Is it sufficient to add PIMs to standard regulation?

A. The addition of carefully designed Performance Incentive Mechanisms (PIMs) to standard COSR can mitigate some of the shortcomings listed in the article by Lowry and Woolf. PIMs can encourage desired behavior and discourage undesirable ones. PIMs can be especially effective in promoting certain public policy goals that are resistant to promotion through standard ratemaking. For that reason, virtually all PBR regimes include PIMs with financial benefits and/or penalties attached to the utility's performance on the PIM metrics.

That said, PIMs are not effective in addressing the capex bias, the throughput incentive, or the weak incentives to improve firm efficiency, all traits of standard COSR. Bottom line, simply bolting PIMs onto standard COSR can treat the symptoms, but not the causes of the failures of COSR. Regulators should pursue not only the limited cases where

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[6] Revenue = Incentives + Innovation + Outputs. This formulation captures the purposes of the revised British regulatory scheme. While not a formula, it emphasizes that a utility's allowed revenues contain Incentives to achieve announced Outcomes and it is structured to induce Innovation by the utility.

PIMs are effective but also address the fundamental biases caused by COSR.

The Benefits of Performance-Based Regulation ("PBR")

Q. Please discuss the typical elements of Performance-Based Regulation and relate them to COSR's "shortcomings."

A. There are typically six elements of PBR regimes:

- Identification of desired public policy outcomes.
- A multi-year rate period (MYRP), often 3, 5, or 8 years.
- A "revenue adjustment mechanism" (RAM) governing year-to-year rate levels during the MYRP.
- Revenue decoupling.
- Performance Incentive Mechanisms with positive and/or negative incentives.
- (In some cases) a revenue-sharing mechanism.

Q. Please discuss these six features of PBR regimes.

A. PBR Element: Identification of Desired Public Policy Outcomes

Because PBR, by definition, shifts regulatory attention toward a utility's performance, regulators (and legislators) often examine and adopt public policy goals or "outcomes" that regulation should seek to achieve. These outcomes can be a combination of actions within the historic performance of the utility (*e.g.*, service quality) and newer outcomes (*e.g.*, decarbonization, DER deployment).

Figure 1. Hawaii PUC PBR Regulatory Outcomes

Regulatory Goal	Regulatory Outcome	
Enhance Customer Experience	Traditional	Affordability
		Reliability
	Emergent	Interconnection Experience
		Customer Engagement
Improve Utility Performance	Traditional	Cost Control
	Emergent	DER Asset Effectiveness
		Grid Investment Efficiency
Advance Societal Outcomes	Traditional	Capital Formation
	Emergent	Social Equity
		GHG Reduction
		Electrification of Transportation
		Resilience

Figure 1 shows the list of outcomes identified by the Hawaii Public Utilities Commission when adopting its recent PBR regime. As can be seen, the Hawaii PUC identified three categories of regulatory goals: i) enhancing customer experience; ii) improving utility performance; and iii) advancing societal outcomes. Further, the Hawaii PUC sorted the outcomes into "traditional" and "emergent." PBR is seen by the Hawaii PUC as able to retain the traditional outcomes of regulation while adding a set of new, emergent outcomes. As of this writing, the Hawaii PUC is examining and adopting PIMs where appropriate to motivate the outcomes.

Q. Are you advocating that the UTC adopt the Hawaii Commission's outcomes?

A. No, I am not. Hawaii developed its preferred outcomes using a process that I think is a best practice and I recommend its use. I hope that the UTC examines and adopts a comparable list of desired outcomes for any PBR regulatory system it examines. As I understand, the Commission is undertaking a similar process in its PBR investigative docket. But I cannot discern that the Commission's process affected PSE's filing.

In Docket No. U-210590 (Proceeding to Develop a Policy Statement on Alternatives to Traditional Cost of Service Rate Making) the Commission has set a course to explore the most important questions about alternatives to traditional COSR. Phase I of that process is mostly completed and the Commission will issue its first policy statement in March 2023. That policy statement will be an opportunity for the Commission to announce high-level goals and outcomes for utility regulation and to motivate the detailed discussions that commence in March 2023.

It is, of course, unfortunate that the Commission is having to deal with PSE's PBR filing before it has worked out the goals and mechanics of performance-based regulation suitable for Washington at this time. This calendar mismatch means that the Commission must rule in this docket on important PBR issues before it has developed and announced the big-picture context developed in the Docket U-210590 process. However, the existence of the policy docket which is considering and evaluating different approaches to PBR does not prevent the Commission from adopting innovative PBR approaches in this case.

From my experience with the process used by the Hawaii PUC, I suggest that the Washington process in Docket U-210590 could be accelerated. The stakeholder group could begin considering the seminal issues in Phase 2 ***prior to*** the Commission's policy statement in March 2023. Much of the process entailed in Phase 2 will be educational: parties and other experts will present alternative approaches to the RAM, MYRP duration, modeling of results, etc. This could begin as early as, say, October 2022. As Phase 2 proceeds, the Commission's findings in the March 2023 policy statement can be introduced to guide evaluation of the alternative methods being examined. This will allow the Commission to issue a policy statement on the Phase 2 issues in late 2023. The policy statement will be guidance to the utilities and other parties as they assess structural options for PBR. Of course, not all of the details will be fully settled: that will happen when the Commission entertains a PBR filing by a utility.

Q. Please comment on the second common element of PBR.

A. PBR Element: A multi-year rate period (MYRP), often 3, 5, or 8 years.

There are two basic reasons a multi-year rate plan is usually incorporated into a PBR regime. First, depending on other features of the plan, a multi-year rate plan can restore some of the incentives toward efficiency that have been lost in standard COSR. I will discuss this further later when discussing the Revenue Adjustment Mechanism.

Second, a longer period between rate cases allows the utility to "prove out" business strategies that can improve service and lower costs. Standard COSR tends to focus the utility's attention on the period ending with the next rate case, not on the longer run. As part of a project called "Utilities 2020," I interviewed a dozen utility CEOs on this exact topic. Here is an excerpt from the Utilities 2020 Report:

> *"When questioned, large majority of the CEOs agreed that, under current practice, regulation does not provide utilities with meaningful incentives to improve internal efficiencies. We heard that <u>"if we save a buck, they take it away from us in the next rate case," and that "our best outcome is that we recover the cost of a measure; there's no upside."</u> They agreed that higher firm efficiencies are possible and that these could function to offset higher costs expected over the next two decades."*[7]

I have attached a copy of the public version of Utilities 2020's report as Exh. RJB-4.

The Hawaii PUC adopted a 5-year effective period for its recently adopted PBR order. My client, Blue Planet Foundation, had advocated for an 8-year period. The RIIO regime in the United Kingdom has an 8-year duration. Periodically, Pacific Economics Group has prepared summaries of the terms of PBR regime in the U.S., Canada, the UK, and Australia for electric and gas utilities. A quick review of the statistics about the duration of MYRP terms shows that, in 2017, the mean number of years in an MYRP in the United States is 3.66 years. The corresponding values for Australia, Canada, and the U.K. are 4.04, 3.74 and 8.00 years, respectively.

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[7] Lehr, R. and R. Binz. Utilities 2020 Report. July 2013 (Exh. RJB-4).

Q. Is it appropriate to adopt multiyear rate plans without a revenue-cap approach?

A. It is possible, but in my view undesirable, to formulate a multiyear rate plan using cost-of-service principles. That is effectively what PSE is proposing in this case. The proposed multiyear rate plan computes the traditional revenue requirement for each of the three years based on projections of capital expenditures and trending of O&M costs from the Company's five-year planning document. It's fair to say that the MYRP proposed by PSE is designed to produce the authorized rate of return for PSE in each of the three years ***without anything else happening***. PSE does not need to become more efficient; PSE does not need to improve its performance and collect on the upside rewards of the proposed PIMs; PSE is even protected from "unforeseen" inflation.

Finally, if PSE ***does*** significantly improve its efficiency, thereby increasing its actual earnings during the MYRP, the Company's upside is limited. Each year of the MYRP, PSE's actual earnings are calculated and any earnings greater than fifty basis points above the authorized rate of return are placed into a deferred account, with the disposition of the funds to be determined by the Commission later. This is the precise circumstance that the utility executive complained of in the Utilities 2020 report. I will return to this issue later, on page 20 of my testimony.

In my view, it would be preferable to develop an index that is independent of PSE's internal budget process. For example, PSE's non-fuel, non-purchased power revenues grew at an annual rate of about 4.4% from 2009-2018. This could be a first approximation to a reasonable year-on-year growth rate in revenues for a three- or five-year MYRP. Importantly, this is growth in total revenues, not rates. As such, it includes growth in number of customers. And as discussed beginning on page 33, there likely is lumpiness in capital expenses that must be addressed by an adjustment for major projects.

Q. What is meant by the fourth common element of the standard PBR regime?

A. PBR Element: A "revenue adjustment mechanism" (RAM) governing year-to-year rate levels during the MYRP.[8]

If a regulator regulates using a multiyear rate plan, some important questions are: *How do rates change from year to year? Are rates frozen? Can the utility file a rate case?*

There are several possible answers, and they will be shaped by the circumstances of the case. The first MYRPs came in the form of "stay out" provisions that were imposed (or negotiated) when a utility was "overearning." This meant that a utility could not file for higher rates for a set number of years, protecting customers from new rate increases while allowing the utility to maintain its ability to exceed its authorized rate of return for a period while the cost pressures slowly ate away at the "excess" returns. A well-documented version of this involved MidAmerican Energy in Iowa. Unit prices persisted in Iowa for seventeen years without a rate increase during the period.

> *"For seventeen years, from 1995 to 2012, MidAmerican did not change its retail prices in Iowa; nor did it utilize 'adjustment mechanisms' to track costs. Instead, the rates in effect in 1995 were continued without change through a series of settlement agreements involving MidAmerican, the staff of the Iowa Utilities Board, the Office of Consumer Advocate, and other interested parties. The terms of the settlement*

[8] Sometimes the revenue adjustment mechanism is called an "attrition relief mechanism" or "ARM." Dr. Lowry uses this term instead of RAM. The concept is the same: a mechanism to adjust rates each year of a MYRP.

agreements evolved over time but generally provided for a fixed settlement period, a formula for sharing over-earnings and an 'escape clause.''[9]

For a variety of reasons, MidAmerican was able to exceed its authorized return persistently for an extended period of time. Every four or five years, the company, Iowa Utilities Board staff, and the state consumer advocate would negotiate a refund for customers, and then permit the utility to keep charging the same rates, sometimes accompanied by changed accounting conventions.

More commonly, a utility's rates or revenues for each year of the MYRP are set at the beginning of the MYRP or are determined by an index or a formula applied during the MYRP. When combined with a decoupling provision, the annual escalation by index or formula affects total allowed revenues, not prices. If the annual revenue levels are determined by an index, the resulting system is called a "revenue cap."

The practice of setting an indexed ***price cap*** was commonly used by states and the Federal Communications Commission in the 1990s to give AT&T and the local telephone companies flexibility as competition invaded the telecom industry. (Since the price cap was not accompanied by decoupling, it was not a ***revenue cap***.) In Canada and many other countries around the world, the most common method for setting year-to-year price or revenue levels for energy utilities is captured by the formula "RPI minus X" where RPI refers to a price index and X represents the rate of change in industry productivity. This and similar formulas have been used in the U.K., Germany, Sweden, Norway, Finland, Malaysia, New Zealand, Australia, and Brazil, among other countries.

[9] Utilities 2020 Report (Exh. RJB-4), p. 21.

Q. What are the advantages of revenue cap regulation?

A. There are two significant aspects of revenue cap regulation, each of which improves traditional cost-of-service regulation. First, if the Revenue Adjustment Mechanism is based on an external index, the utility has a much stronger inducement to become more efficient. In this case the utility is not competing with its own costs, but with an external index, usually related to a collection of similar firms and to inflation. Becoming more efficient redounds to the utility's benefit during the MYRP. In the other direction, under an externally driven revenue cap, a utility should not persist in inefficient behavior since there is no assurance that excessive spending will ever be "recovered" in a subsequent rate case filing.

Second, since year-to-year changes in the utility's allowed revenues is not focused on the level of capital investment, revenue cap regulation lessens the capex bias described earlier. This feature has an important follow-on effect, too. If a utility's revenues are capped while earnings are not, the utility is driven strongly to select the least cost solution to a need of the grid. If a "non-wires alternative" (NWA) is lower cost than a utility capital-based solution, the utility can lower its costs and thereby increase its earnings by selecting the NWA. Similarly, with Energy Efficiency measures and DER deployment: in a regime of revenue caps (with decoupling) the utility's revenues are no longer reduced when customers elect energy efficiency or roof-top solar. Finally, a utility is not "penalized" for purchasing power from independent power producers since its non-fuel revenue levels won't depend on plant investment. Revenue cap regulation is short of "earning a return on purchased power," but it has much the same effect by dampening a utility's perceived need to build and own instead of buy.

PBR Element: Revenue decoupling.

As noted above, a MYRP combined with revenue decoupling results in a system of rate control called revenue cap regulation. The Commission has been using revenue decoupling since 2016, when it joined the ranks of states moving toward incentive regulation and decoupling for electric utilities.

However, there may be reasons to consider modernizing decoupling mechanisms to promote beneficial electrification projects such as vehicle electrification or migrating space conditioning from natural gas to electric heat pumps.

PBR Element: PIMs with positive and/or negative incentives.

A long-standing feature of incentive regulation plans of all stripes is the "Performance Incentive Mechanism" or PIM. The UTC has some experience with PIMs in its use of Service Quality Indicators (SQIs) and their associated rewards or penalties. PSE first implemented its Service Quality Program ("SQ Program") pursuant to a settlement stipulation in the dockets approving the merger between Washington Natural Gas Company and Puget Sound Power & Light Company per its 1995-1996 Merger Dockets[10] (1995-1996 Merger Stipulation). The stated purpose of the SQ Program was to "provide a specific mechanism to assure customers that they will not experience deterioration in quality of service"[11] and to "protect customers of PSE from poorly-targeted cost cutting"[12] as a result of the merger. The SQI scorecard has been updated several times, but remains primarily focused on service quality and customer services, and does not address other important goals. As part of its consideration of PIMs in this docket, the UTC should review these

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[10] *In re Application of PSP&L and WNG for an Order Authorizing Merger*, Docket Nos. UE-951270 and UE-960195.

[11] *Id.*, Fourteenth Supplemental Order Accepting Stipulation (Feb. 5, 1997) (Stipulation at 11:11-15).

[12] *Id.*, Fourteenth Supplemental Order at 32.

legacy PIMs to ensure they are designed to achieve the correct outcomes and that they are aligned with new PIMs proposed in this case.

PIMs can be focused on areas of achievement that regulators or other policy makers (legislators) wish to see pursued. There is much literature on the selection and design of PIMs that will aid the Commission in its consideration of PIMs. One area that is sometimes overlooked is that the aggregate "value at risk" with PIMs should be large enough to get the utility's attention and cause it to make meaningful efforts to perform. This applies whether the PIMs are reward-only, penalty-only, or combined reward/penalty.

I should note that, while adding well-designed PIMs are preferred because they can improve either COSR or revenue cap regulation, a regulator can postpone adding some or all PIMs until the structural questions are answered.

NWEC witness Amy E. Wheeless will address PSE's choices of PIMs and the associated metrics in her testimony and outline modifications to the PIMs that NWEC thinks should be implemented. Another witness for the Joint Environmental Advocates, Ed Burgess, will also suggest another PIM for consideration related to the ratio of new gas to electric customers, as a way to remove the bias for the Company to continue growing its gas business.

PBR Element: (In some cases) a revenue sharing mechanism.

A few jurisdictions, although not most, have incorporated an "earnings sharing" mechanism (ESM) in its PBR regime. The concept is that if a utility under PBR regime exceeds its authorized return, the excess is shared between customers and shareholders. In some cases, ESMs provide that customers also share ***under*** earnings. The PSE proposal provides an annual earnings test. If earnings exceed fifty basis points above the authorized return on equity, the excess will be deferred in an account for "refunds to customers or another determination by the [C]ommission[.]"[13]

An earnings sharing mechanism has some surface appeal and is usually characterized as a customer benefit. In my view, the story is not that simple.

Recall the complaint of the executive ("if we save a buck, they take it away from us in the next rate case"). The existence of a tight cap on earnings will dull any incentive in PBR for the utility to become more efficient or even select the "least cost" resource when given a choice. This is especially true in the case of the PSE proposal. Earnings levels are checked each year of a three-year plan and profits that are one-half percent higher than authorized are taken away. A good example of killing the golden goose.

When a company operates in a revenue cap regime, the essential bargain with customers is that total revenues cannot increase beyond a certain rate year-to-year. In most revenue cap regimes, that rate is tied to a cost or price index and is reduced by a "consumer dividend" or "stretch factor." The consumer dividend (*e.g.*, -0.25 %) reduces what would otherwise be the RAM applied to total revenue changes from year to year. In other words, in such a revenue cap regime, customers get a benefit at the front end of the new system because revenue escalation is slowed by the consumer dividend.

The question of whether to include an ESM was examined in the recent Hawaii PBR docket. The Commission recognized the tension between providing the utility with strong incentives to operate at least cost and treating customers fairly. The Hawaii Commission adopted a wide "deadband" of three hundred basis point on either side of the authorized ROE before any earnings sharing (up or down) commences. Thus the Hawaii model ensures

[13] RCW 80.28.425(6).

that the incentives of the revenue cap regime remained strong while protecting customers against theoretic stratospheric returns for the utility.

There is another way the Commission could blunt the anti-efficiency impact of an ESM: instead of using an annual earnings check-in, the earnings measurement and sharing calculation could be moved to the end of the MYRP – at the end of three years in the case of the PSE proposal.

Q. What might be the utility's motivation for pursuing PBR?

A. In my experience, utilities filing for PBR plans, and especially multiyear rate plans, are motivated by four outcomes:

- Reduced "regulatory lag."
- Increased regulatory "certainty."
- Potentially reduced regulatory burdens and administrative costs.
- Increased flexibility for the utility in planning and capital expenses.

Indeed, one or more of PSE's witnesses cites each of these motivations in their testimony. PSE witness Adrian J. Rodriguez describes how PSE's proposed MYRP increases "certainty" and reduces "regulatory lag." Exh. AJR-1T at 43. PSE witness Ann E. Bulkley repeatedly cites the reduction of "regulatory lag" owing to the MYRP throughout her testimony. PSE witness Jon A. Piliaris (Exh. JAP-1T at 4) cites "reduced administrative costs" as a benefit of multiyear rate plans. Witness Rodriguez (Exh. ARJ-1T at 14) cites increased flexibility in planning capital expenditures as a benefit of the MYRP. There are many other references in PSE's testimony to these four utility-benefitting outcomes.

I agree with PSE's analysis of the four benefits the Company's witnesses identify. All four effects change regulation in a way that is beneficial to the utility and, potentially, to customers if those benefits pass into consumer rates. However, some of these changes, ***depending on implementation***, could reduce at least one favorable feature of traditional COSR. Specifically, regulatory lag has long been cited by regulators as an inducement to the utility to become more efficient. Thus, eliminating regulatory lag is something of a double-edged sword for regulators and consumers. As I will discuss further below, regulators can and should shape PBR so that it induces efficient behavior in the utility even as regulatory lag is reduced.

Q. Why should *regulators* pursue PBR?

A. The benefits of PBR enumerated by PSE witnesses form some of the reasons why regulators should pursue PBR. But PBR presents additional opportunities for utility regulators, allowing them to i) improve the outcomes of economic regulation; ii) equip utilities with the flexibility to respond to the fundamental changes in the energy sector; iii) expand the outcomes of regulation to include important public policy goals; and iv) incentivize certain specific behaviors. Simply put, COSR is no longer optimal, and can be improved by focusing on the outcomes of regulation.

Q. How does SB 5295 affect the Commission's authority to adopt a PBR regime?

A. Speaking as a former commission chair, and not as an attorney, I note the Commission has broad authority to set just, fair, and reasonable rates pursuant to RCW 80.28.020. Senate Bill 5295 explicitly retained this authority of the Commission when it provided that "[t]he provisions of this section may not be construed to limit the existing rate-making authority of the commission."[14] Further, Senate Bill 5295 also provided the Commission with broad discretion to use "any standard, formula, method, or theory of valuation reasonably

[14] RCW 80.28.425(10).

calculated to arrive at fair, just, reasonable, and sufficient rates[,]" to determine whether rates are fair, just, and reasonable.[15] Further, in deciding whether to approve a petition for a rate increase, the Commission must consider the "public interest" meaning "environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices of a gas or electrical company regulated by the commission[.]"[16]

While the Commission has an obligation to fairly value a utility's property and to integrate that value into rates, the Commission is not required to set revenue using cost-of-service regulation. Indeed, the legislative directive for the PBR policy docket required the Commission to consider "alternatives to traditional cost of service ratemaking[.]"[17] Washington law provides the Commission with "sufficient flexible authority to determine the value of utility property for rate making purposes and to implement the requirements."[18] Further, the statute governing valuation of a utility's property value specifically provides that "[n]othing in this section limits the Commission's authority to consider and implement performance and incentive-based regulation, multiyear rate plans, and other flexible regulatory mechanisms."

Performance-based regulation that includes a revenue cap can achieve these purposes because it is a method of valuation that seeks to constrain costs and realign incentives to

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[15] "In ascertaining and determining the fair value of property of a gas or electrical company pursuant to (b) of this subsection and projecting the revenues and operating expenses of a gas or electrical company pursuant to (c) of this subsection, the commission may use any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates." RCW 80.28.425(3)(d).

[16] RCW 80.28.425(1).

[17] Legis. Dir. C 188, 2021, RCW 80.28.425.

[18] RCW 80.04.250(1).

achieve core objectives set out through PIMs and metrics. Further, I also understand that the UTC has utilized multiyear rate making prior to the passage of Senate Bill 5295, and thus we should assume that since the Commission had authority to adopt PBR previously, it can continue to do so. In short, the Commission has the authority to fashion a better PBR regime than the one sought by PSE.

PSE's Proposed MYRP Fails to Include Critical Components of PBR

Q. Please discuss PSE's application.

A. PSE has taken advantage of the new statute to incorporate projections of capital and operating expenses for the three-year duration of the proposed MYRP. The new statute either expanded or ratified the Commission's authority to interpret the "used and useful" regulatory standard in a way that a current rate order can incorporate future plant additions and projected operating expenses. Functionally, this amounts to business as usual in a broad sense. In my view, PSE's PBR regime is indistinguishable from three successive rate cases transacted at the beginning of a three-year period.

The Company attributes its reluctance to move very far on PIMs to the existence of the Commission's PBR policy docket. But that raises the question "What is the purpose of the PSE application?" As I will discuss next, there is very little incentive in this proposed incentive regulation regime.

Q. Please respond to testimony of Dr. Mark N. Lowry.

A. Dr. Lowry is PSE's main witness for its PBR proposal. I worked closely, but not always in agreement, with him in the Hawaii PBR docket that I have referenced several times. I think it's fair to say Dr. Lowry and his firm Pacific Economics Group are true experts and among the very best thinkers on incentive regulation.

While Dr. Lowry clearly explains the theory behind PBR and why it is to be preferred over traditional cost of service regulation, he does not explain why the PSE proposal fails to integrate the core elements of PBR into its proposal. I will expand on this further next.

In addition to my commentary, the testimony of Amy Wheeless (Exh. AEW-1T) responds to Dr. Lowry's testimony by providing a detailed analysis and recommendations about PSE's proposal to adopt new performance metrics and create new PIMs regarding demand response and transportation electrification as a part of this rate case.

Q. What is Dr. Lowry's overall assessment of the PBR plan proffered by PSE?

A. Dr. Lowry evaluates PSE's PBR plan on four criteria: fairness, cost control incentives, regulatory efficiency, and attention to other goals. I will discuss each in turn.

Q. What is Dr. Lowry's assessment of the fairness of PSE's MYRP?

A. Dr. Lowry lists the "**benefits**" for PSE and the "**protections**" for customers that he finds in the PSE proposal. The contrast in these two terms is telling. As will be seen, there are **benefits** to the Company from the MYRP, but only "**protections**" for customers – no benefits beyond those provided by traditional regulation.

For PSE, the **benefits** are as follows:

> *"revenue growth would be based on the Company's financial plan, timely, and subject to an adjustment for any unforeseen inflation. Revenue decoupling would reduce the risk of volatility in billing determinants. Subject to statutory limitations, PSE could file a rate case if it underearns."*[19]

[19] Exh. MNL-1T at 48.

Dr. Lowry is correct that these are benefits to PSE that go beyond the results of regulation as currently practiced. The Company is freed from any delay between the incurrence of costs and their inclusion in rates. And despite the MYRP bargain, the Company can still file for new rates.

When it comes to **protections** for customers, he lists these seven:

1) The Commission would decide the extent to which it would fund PSE's budgeted cost growth.

   Comment: No change from UTC regulation today.

2) The Company would be obliged to operate under the Commission-approved revenue requirement for two years.

   Comment: This is a regular feature of standard regulation. No news here.

3) Revenue to reimburse PSE for the annual cost of its capex during the plan may be refunded to customers if the assets are later found not to be used and useful or their cost is deemed imprudent.

   Comment: Again, this happens today in COSR.

4) The ESM would asymmetrically favor customers. The entirety of weather-normalized earnings in excess of a modest fifty basis point dead band would be returned to customers.

   Comment: The change of earning 0.50% above authorized in one year is small.

5) PSE would absorb the risk of fluctuations in loads for some large-volume customers.

   Comment: This is because large customers are not subject to decoupling. Unclear how this protects customers.

6) Rate growth would be more predictable.

Comment: This is true because rate increases are known in advance. Doubtful this is an actual protection.

7) The term of the MYRP would only be three years.

Comment: This is like the old joke, "The food here is terrible, and the portions are too small." In fact, a well-designed MYRP will benefit customers more the longer it lasts. Similarly, a longer MYRP allows utilities to "prove out" firm efficiency measures that they might not undertake if the time between rate cases is shorter. This is the exact logic used in Hawaii when the PUC adopted a 5-year MYRP. Unfortunately, the MYRP proposed by PSE in this case is not well-designed and the Commission should not allow it to persist for three years.

Q. What is Dr. Lowry's assessment of the "cost control incentives" under the MYRP?

A. Dr. Lowry reports that

> *"[t]he Company's cost control incentives would be strengthened by the MYRP on balance. The PSE MYRP would provide significant incentives to contain O&M expenses (or "opex") since revenue growth for these kinds of costs is linked to expected rather than actual cost growth between rate cases."*
>
> Exh. MNL-1T at 49.

There are two responses here. First, rates in standard regulation are set based on an adjusted test year (either past, current, or future). Following such rate setting, utility operations proceed and there is a degree of pressure to contain costs since new rates are not available until a new rate case is filed and approved. In the MYRP proposed by PSE, rates for years 2 and 3 ***increase without a rate filing***, in accordance with increased cost projections. It is difficult to see how this situation does anything except <u>reduce</u> pressure to contain costs compared to standard regulation. Second, "expected" vs. "actual" cuts two ways. Actual costs might be less than expected costs, in which case earnings will grow with no change in effort by the Company.

Dr. Lowry admits that "[t]he Company's ability to file a rate case during the MYRP is a fairly unusual feature of the framework," but opines that "the proposed provision is unlikely to trigger a rate case." Exh. MNL-1T at 49.

Given the "on one hand, on the other hand" nature of these observations, the MYRP proposed by PSE appears not to offer any serious boost to cost-control incentives that exist otherwise. In actuality, PSE's rates for three years will be based on its projections, at inception, of operating and capital costs each of the three years. And there are two off-ramps: i) rate adjustments if inflation is greater than expected; and ii) the ability to file a rate case. The only feasible way in which this arrangement could spur increased cost control is if the original projections are too low and/or the Company decides not to file a permitted rate case.

Q. What is Dr. Lowry's assessment of the third measure, "regulatory efficiency," under the MYRP?

A. Dr. Lowry finds that "MYRPs should improve the efficiency of regulation and the Company's MYRP can accomplish this, first and foremost by reducing the frequency of rate cases."

I agree there is a potential for increased regulatory efficiency. But any potential efficiency is undermined by the following two provisions: i) PSE is allowed to file a rate case during the pendency of the plan; and ii) the Commission will be required to conduct an "earnings sharing" measure of the Company's earnings each year. On this first point, Dr.

Lowry assumes that "the Company would likely file a rate case anyways in Year 3 in order to have new rates effective upon the expiration of the plan." Bottom line, if the counterfactual assumption is that PSE files a rate case every other year, there would be little savings in terms of regulatory time.

Q. What is Dr. Lowry's assessment of the last measure, "other goals," under the MYRP?

A. Dr. Lowry notes that PSE and all Washington utilities are subject to many requirements, both legislative and regulatory, including to decarbonize its energy supply, aggressively pursue DSM opportunities, and spread benefits of the energy transition equitably. He reports that "[t]he Company's MYRP proposal encourages attention to these other goals through revenue decoupling and its scorecard of metrics and PIMs." Exh. MNL-1T at 51.

I agree with Dr. Lowry as far as those three categories of goals are concerned. Decoupling and targeted PIMs are two ways that regulation can accomplish some of the desired outcomes that are not naturally encouraged by standard regulation. PSE's MYRP certainly includes decoupling and PIMs, although both of those have already been addressed in Washington regulation prior to the proposed MYRP. However, the MYRP proposed by PSE ***does not*** encourage the Company to aggressively decarbonize its energy supply, or spread the benefits of the energy transition equitably, because PSE's proposal does not include either metrics or other financial incentives that would encourage the Company to achieve these goals, explained further in the Response Testimony of Amy Wheeless.

Q. Are there any other goals besides those listed by Dr. Lowry?

A. Yes. Earlier I discussed the shortcomings of standard cost-of-service regulation. Since PSE's MYRP is based on cost-of-service, this MYRP will retain some of those shortcomings. The type of regulation requested by PSE retains, for example, the capex bias that promotes continued capital investment, rather than an outcome-focused approach economic regulation achieved through PBR.

This point can best be illustrated by considering how Distributed Energy Resources (DERs) fare under traditional COSR and how they might be considered under PBR with revenue cap regime. The Hawaii PUC grappled directly with this and related questions in approaching its PBR decision.

When a utility's revenues are based on the familiar cost of service equation

Revenue = Operating Expenses + Depreciation + Taxes + [(Rate Base) x ROR],

the firm's profitability is captured in the last term: rate base times rate of return. It is completely understandable (and rational) that a utility regulated under that revenue formula will have a strong incentive to add rate base. DERs collide directly with that aspiration.

This point is made by Dr. Lowry in his report presented to Lawrence Berkeley National Laboratory:

> *"DERs pose special incentive issues under COSR. Consider first that all forms of DERs reduce revenue from usage charges. Since costs of non-energy inputs such as capital are largely fixed in the short run, increased reliance on DERs reduces utility earnings until base rates can be raised in the next rate case. This disincentive abates with more frequent rate cases.*
>
> *A second incentive issue arises from the fact that DERs can reduce opportunities for utilities to grow rate base. The problem is greatest for assets, such as generation capacity and substations, the need for which is closely tied to load."*[20]

[20] Lowry, M., and T. Woolf (Exh. RJB-3), p. 13.

In clear terms, Dr. Lowry is saying that cost-of-service regulation presents incentives (higher revenues and larger rate base) that collide directly with the use of DERs. Without attention to these incentives, a utility will under-use DERs, even when they are lower cost to the utility and to customers. Importantly, the MYRP proposed by PSE and evaluated favorably by Dr. Lowry does not change these undesirable incentives at all.

The Commission Should Adopt Revenue Cap Regulation to More Efficiently Control Costs

Q. What is PSE's attitude toward revenue cap regulation?

A. The Joint Environmental Advocates propounded a discovery request to PSE about its attitude toward revenue cap regulation as discussed by Dr. Lowry in his report. Here is PSE's response, for which Dr. Lowry is the responsible person:

> "Puget Sound Energy ("PSE") never evaluated the indexing approach to the design of a revenue adjustment mechanism which is discussed in Dr. Lowry's report starting on page 37. Dr. Lowry explains in those pages that this approach to ratemaking frequently provides inadequate funding for capital expenditures in the short run, and this has frequently led to the approval of supplemental capital funding (e.g., capital cost trackers) in multi-year rate plans that include such an index.
>
> The design of comprehensive revenue cap indexes is particularly complicated for a vertically integrated electric utility ("VIEU") like PSE for reasons that include the following.
>
> - They are engaged in generation as well as transmission and distribution.
> - The extent of involvement by VIEUs in these activities varies, as do the age and nature of the generation facilities that they own.

- It is challenging to design a single revenue cap index that applies to all of these services."[21]

Q. Do you agree with PSE's reasoning in its response to the data request for not considering revenue cap regulation?

A. No, I do not. PSE's core contention is that vertically integrated electric utilities ("VEIUs") are not suited for revenue cap regulation because such a revenue cap index is "challenging" to design for a company with generation as well as transmission and distribution ("T&D") resources. The investment needs of the generation business tend to be "lumpier" than the investment needs of the T&D operations. The revenue requirement for the T&D operation tends to increase steadily over time, while the generation revenue requirement may rise sharply but only occasionally—so goes his argument.

But PSE's position about the inadvisability of a revenue cap for PSE is belied by the recent experience in Hawaii. In fact, a revenue cap ***can*** be designed to accommodate the needs of a vertically integrated utility.

Hawaiian Electric is a vertically integrated electric utility with three subsidiaries, each with a generation department. The Hawaii PUC recently adopted a PBR revenue cap regime that employs an indexed revenue cap. The design of that cap was highly debated and both Dr. Lowry and I filed comments and reports on the subject. Recognizing the "lumpiness" of generation investment, the Hawaii PUC's PBR regime is also designed to allow large, extraordinary capital investment additions such as a new power plant to be considered "outside the cap." The detailed requirements for investment or expenses that qualify for extraordinary cost recovery in Hawaii is called the Exceptional Project Recovery

[21] Exh. RJB-5, PSE Response to NWEC DR No. 34.

Mechanism. This type of regulation is sometimes referred to as a hybrid revenue cap approach.

There is no reason the UTC could not use a similar approach with Puget Sound Energy. An indexed revenue cap could apply to total revenues each year and a decoupling adjustment would true up actual revenues to allowed revenues. In periods of regular growth in generation investment, the revenue cap would operate on revenues associated with all three functions – generation, transmission and distribution.

It is important to remember that not all generation investment is lumpy. In any given year, generation-related revenues under a revenue cap will increase to cover normal growth such as equipment overhaul or replacement at power plants. These regularly growing costs are directly addressed by an annual revenue cap that grows over time.

To the extent that PSE has or foresees a large, extraordinary capital project, the Commission could consider an "outside the cap" adjustment that would permit allowed revenues to move up more than the index would otherwise allow. This system ensures that the benefits of a revenue cap, discussed earlier, apply to the large majority of the utility's revenues while ensuring that large, irregularly scheduled capital costs are accommodated.

Q. Do you agree with PSE's concerns that the Commission cannot adopt PBR without first completing its policy docket?

A. No. While policy statements generated through Docket No. U-210590 would provide important and helpful guidance to utilities as they develop multiyear rate plans, the Commission does not have to wait until completion of that policy docket before adopting performance-based regulation components. No language in the implementing statute prohibits the Commission from adopting PBR before it completes its policy docket. Quite the opposite, the statute requires utilities to propose MYRPs starting in January 1, 2022, for every general rate case filing of a gas or electric utility company.[22] The Commission is required to "align, to the extent practical, the timing of approval of a multiyear rate plan of an electrical company submitted pursuant to this section with the clean energy implementation plan[.]"[23] The Commission will issue an order regarding PSE's CEIP next year, well in advance of the completion of the policy docket—which is not scheduled to end until December 2025.[24]

In other words, waiting for the policy docket to terminate before acting on PBR would mean waiting years before taking advantage of the innovative opportunities presented by PBR—when the statute contemplates that utilities would be regulated by performance-based rates starting with any proposals submitted *this year*. Further, it would mean waiting 3 years after approval of the CEIP before taking action to implement the CEIP through MYRPs.

Recommendations

Q. What are the elements of the preferred model for PBR as advocated by your clients?

A. As I have developed throughout this testimony, I think the UTC should examine a system of regulation for PSE with the following features:

- A unifying set of consensus outcomes targeted in the regulation.

[22] RCW 80.28.425(1).

[23] RCW 80.28.425(1).

[24] Appendix - PBR Work Plan Final, Dkt. No. 210590, Filed on Jan. 27, 2022.

- A revenue cap beginning at base rate levels in the first year and escalating based on a formula such as RPI-X and including "Y," "Z" and "CD" elements.[25] Other RAM formulas are possible.
- A duration of 5 years.
- Continuation of revenue decoupling.
- The ability of the utility to exceed its authorized return.
- An earnings sharing mechanism applied at the end of the 5-year period, not each year, with a wide deadband.
- Performance standards incorporating PIMs, tracked performance and report cards; with meaningful value at risk (VAR).

Q. Do you recommend the Commission adopt the above-described PBR approach *in this case*?

A. No. It would be difficult to adopt the above-described approach in this rate case. Instead, I recommend that the Commission limit the instant application to no more than a one-year rate case, because it fails to integrate important components of PBR. Further, I recommend that the Commission require in its order that PSE develop a multiyear rate plan proposal for its next rate case that includes the elements I describe more fully below.

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[25] PBR RAMs tend to be more detailed than simply "RPI-X." Other factors are included such as Z, Y and CD factors. The Z-factor represents non-routine cost changes (*e.g*., tax law changes); the Y-factor captures "passthrough" costs such as fuel and purchased power; the CD-factor is the "consumer dividend" or "stretch factor" incorporated into the index calculation.

Q. How do you think the Commission should respond to PSE's current application for a MYRP?

A. I recommend the Commission reject PSE's application for a MYRP. The PSE proposal is quite anemic: it is Reform in Name Only. Unlike other, more robust PBR plans, the PSE proposal seems focused solely on accelerated or improved cost recovery and it adheres to traditional cost-of-service regulation principles down the line. For these reasons, the plan is only loosely connected to the sort of incentive regulation that other states (Hawaii), provinces (Alberta), and countries (the U.K.) are using today.

The distance between what is offered and what is needed is so great that the Commission would be justified in denying the PSE proposal. However, if the Commission is inclined to allow the plan to become effective, it should limit its effectiveness for only one year. Otherwise, the existence of an inferior PBR will interfere with progress toward a true PBR regime in Washington.

Q. What elements should the Commission include in an order that looks ahead to a next-generation PBR regime?

A. Looking ahead to an improved future PBR proposal, the Commission will be faced with several key decisions. The Commission's order in this case should require PSE to include material in its future PBR filing that sets up those key decisions. The required material to be provided by PSE includes:

1. Identification and discussion of the **outcomes** proposed to be achieved with the PBR regime (*e.g.*, improved environmental performance; increased equity among customers; improved utility finances; more energy efficiency; reduced regulatory costs, etc.).[26]

[26] Consider the organization of goals and outcomes used by the Hawaii PUC, included as Figure 1.

2. A primary **multiyear plan** that covers 5 years with an alternative plan that covers 3 years.
3. A proposed **revenue adjustment mechanism** (RAM or ARM) with these characteristics:
    a. It is tied to an external index that is not directly related to PSE's costs.
    b. It permits rate adjustments for extraordinary capital or operating expenses.
    c. It includes a "consumer dividend" or "stretch factor" feature that establishes a minimum level of consumer benefits.
4. A revenue **decoupling** mechanism.
5. A set of **PIMs**, with proposed associated metrics and rewards and/or penalties, which addresses regulatory outcomes such as
    a. Accelerating reductions of greenhouse gas emissions;
    b. Easing economic burdens of low- and moderate-income customers;
    c. Expanding energy efficiency and demand response;
    d. Increasing beneficial electrification.
6. A mechanism for s**haring excess earnings** with customers. The mechanism should apply only at the end of the MYRP and should include a wide "deadband" (*e.g.*, 200 basis points) above PSE's authorized return before sharing begins.

Q. Please restate your recommendations.

A. I recommend the following:

1. Fundamental changes in the energy sector and pressing environmental concerns require utilities to change how they operate and how they are regulated. Simply put,

traditional cost-of-service regulation (COSR) is no longer adequate to the task of achieving the outcomes desired of public policy.

2. While PSE's PBR filing comports with the new statute, it is excessively timid and fails to incorporate the beneficial features that PBR commonly offers. PSE's proposal is indistinguishable from three successive rate cases transacted at the beginning of a three-year period.
3. Due to the limitations of PSE's PBR filing, I recommend that the Commission either reject the plan or limit its effect to one year.
4. The Commission should specify in this case the ingredients to be included in the next PBR plan for UTC consideration.
5. The Commission should use the future PBR proceeding to explore alternatives to cost-of-service regulation, such as revenue cap regulation.
6. The Commission should require PSE to revise its proposed PIMs in line with the testimony of Joint Environmental Advocates witnesses Amy Wheeless and Ed Burgess.

Q. Does this complete your testimony at this time?

A. Yes.