

**EXH. MNL-1T
DOCKETS UE-22 ___/UG-22 ___
2022 PSE GENERAL RATE CASE
WITNESS: MARK NEWTON LOWRY**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

Docket UE-22 ___

Docket UG-22 ___

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

MARK NEWTON LOWRY

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

PUGET SOUND ENERGY

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CONTENTS

I. INTRODUCTION1

II. PURPOSE OF TESTIMONY2

III. PERFORMANCE-BASED REGULATION4

IV. THE COMPANY’S MYRP PROPOSAL16

V. PERFORMANCE METRICS AND PIMS IN THE PSE PROPOSAL19

 A. Development of PSE’s Performance Metrics and PIMs19

 B. Demand Side Management Metrics25

 C. Transportation Electrification Metrics33

 D. Emissions Metrics44

 E. Advanced Metering Infrastructure Metrics45

 F. Additional Equity Metrics47

VI. APPRAISAL OF THE COMPANY’S MYRP PROPOSAL48

VII. CONCLUSION51

PUGET SOUND ENERGY

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LIST OF EXHIBITS

Exh. MNL-2	Professional Qualifications of Mark Newton Lowry
Exh. MNL-3	Report on Performance-Based Regulation for Puget Sound Energy
Exh. MNL-4	Details of Proposed Scorecard Metrics
Exh. MNL-5	Details of Proposed PIMs

1 **PUGET SOUND ENERGY**

2 **PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**
3 **MARK NEWTON LOWRY**

4 **I. INTRODUCTION**

5 **Q. Please state your name, current occupation, and business address.**

6 A. My name is Mark Newton Lowry. I am the President of Pacific Economics Group
7 Research LLC (“PEG”). My business address is 44 East Mifflin Street, Suite 601,
8 Madison, Wisconsin, 53703.

9 **Q. Have you prepared an exhibit describing your education, relevant**
10 **employment experience, and other professional qualifications?**

11 A. Yes. This information is provided in Exh. MNL-2.

12 **Q. Please summarize your professional experience.**

13 A. I earned a PhD in applied economics from the University of Wisconsin and have
14 worked as an economist for more than thirty years. Most of my work has been in
15 the field of utility economics. My specialties include performance-based
16 regulation (“PBR”) and statistical research on energy utility performance. I have
17 testified on these topics in more than 50 rate proceedings. I have additionally
18 spoken at many conferences on these topics and have authored dozens of
19 professional publications. Before becoming President of PEG in 2009, I was a
20 partner in an antecedent company based in Pasadena, California for over 10 years.

1 Prior to that I was a vice president at Laurits R. Christensen Associates here in
2 Madison and spent several years as an assistant professor teaching energy
3 economics at the Pennsylvania State University.

4 **Q. What are your duties at PEG?**

5 A. PEG is a consulting firm that works primarily in the field of energy utility
6 economics. We are well known for our PBR and statistical performance research.
7 Our personnel collectively have over seventy years of experience in these fields,
8 which have a common foundation in economic statistics. Working for diverse
9 clients that include utilities, regulators, government agencies, and consumer and
10 environmental groups has given us a reputation for objectivity and dedication to
11 good regulation. PBR for vertically-integrated electric utilities and gas utilities are
12 specialties.

13 My principal duties as President of PEG are the supervision of research, client
14 consultation, and the provision of expert witness testimony. I also oversee the
15 company's business affairs.

16 **II. PURPOSE OF TESTIMONY**

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

18 A. I am testifying on behalf of Puget Sound Energy ("PSE" or "the Company").

1 **Q. What is the purpose of your testimony?**

2 A. In this proceeding, PSE is filing a rate case and a PBR proposal that includes a
3 multiyear rate plan (“MYRP”). My testimony provides an overview of PBR and
4 MYRPs, describes and appraises the Company’s MYRP proposal, and discusses
5 in some detail the performance metrics in the proposal. Senate Bill 5295 provides
6 for a transformation of Washington energy utility regulation in the direction of
7 MYRPs and other kinds of PBR such as performance metrics and performance
8 incentive mechanisms (“PIMs”). The Company retained PEG to help it develop
9 metrics and PIMs for its MYRP proposal. PSE also asked us to prepare a report
10 and testimony that provides a constructive overview of PBR and discusses the
11 metrics and other PIMS in the Company’s proposed plan. The report is contained
12 in Exh. MNL-3.

13 **Q. Please provide an overview of the report on Performance-Based Regulation**
14 **you prepared for PSE.**

15 A. The report discusses some limitations of traditional ratemaking under modern
16 business conditions and how these limitations have led to the development of
17 PBR. Succeeding sections of the report discuss the major PBR approaches.

18 The final section of the report considers PBR for Puget Sound Energy. It begins
19 by discussing key features of PSE’s operations and regulatory environment. The
20 report notes that the Company is currently operating under several forms of PBR
21 and that rate regulation using MYRPs and PBR has been legislatively mandated in

1 Washington. The report concludes with a discussion of the Company’s MYRP,
2 according particular attention to the metrics and PIMs contained therein.

3 III. PERFORMANCE-BASED REGULATION

4 **Q. Please provide an overview of PBR.**

5 A. Dissatisfaction with the traditional cost of service approach to ratemaking
6 (“COSR”) has prompted the development of diverse alternative approaches that
7 are collectively called “alternative regulation” or “Altreg.” These Altreg
8 approaches vary in the incentives they provide to utilities to perform well. Altreg
9 approaches that provide relatively strong performance incentives are called
10 performance-based regulation.

11 There are four well-established approaches to PBR.

- 12 • Decoupling. The relationship between revenue and system use can be
13 relaxed through such means as revenue decoupling. Decoupling reduces
14 the “throughput” incentive that discourages utilities from embracing
15 demand-side management (“DSM”). It also encourages innovative rate
16 designs that facilitate DSM.
- 17 • Performance Metrics. Metrics can be used to monitor utility activities in
18 key performance areas. They can be paired with targets to measure utility
19 performance. Metrics and targets can provide the basis for PIMs that link
20 the earnings of a utility to its measured performance. Metrics that are not
21 paired with targets or PIMs may be called “tracker” metrics.
- 22 • Targeted Incentives for Underused Practices. Other PBR provisions
23 provide targeted encouragement for desirable practices that utilities tend to
24 underuse. These provisions include pilot programs, management fees,
25 trackers and associated rate riders or deferrals for costs of underused
26 practices, the capitalization of certain costs that are operation and

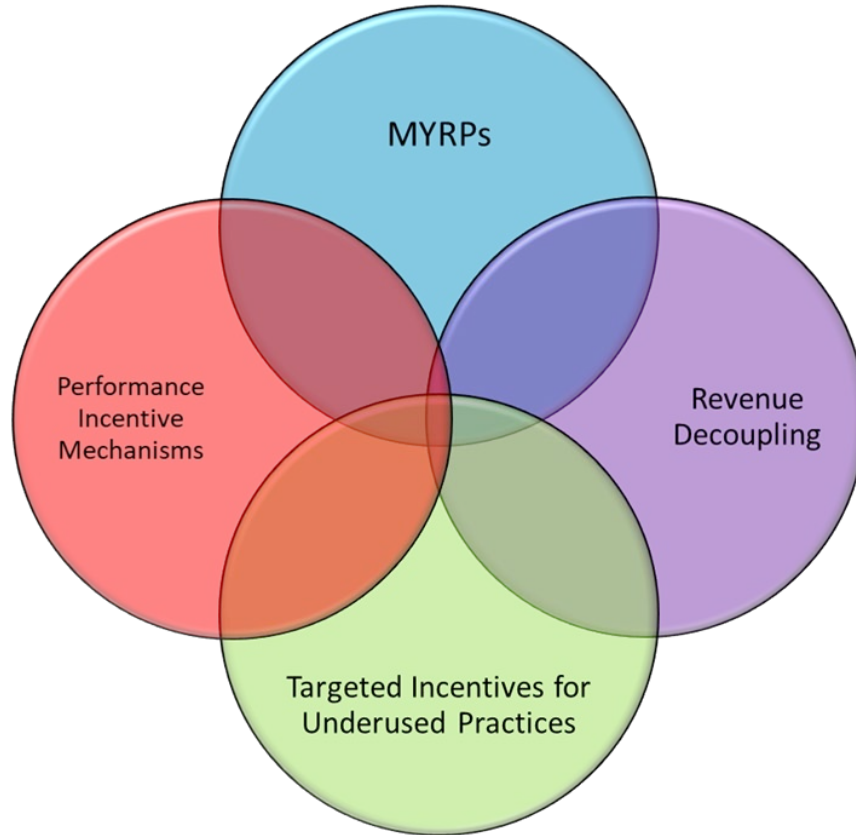
1 maintenance (“O&M”) expenses, and rate of return premiums. A common
2 example is the tracker treatment of DSM expenses.

- 3 • Multiyear Rate Plans. MYRPs strengthen the incentive of utilities to
4 contain the cost of their base rate inputs. This is due in part to a reduction
5 in the frequency of rate cases. Reduced rate case frequency also
6 streamlines regulation, freeing resources in the ratemaking community to
7 concentrate on other matters such as integrated resource and clean energy
8 plans, new rates and services, and important emerging generic issues. The
9 efficiency of regulation is thus enhanced.

10 These PBR approaches are often used in combination as depicted in Figure 1
11 below. For example, multiyear rate plans often feature revenue decoupling,
12 several performance metrics and PIMs, and some pilot programs and trackers for
13 costs of underused practices.

1
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Figure 1
PBR Approaches are Often Combined



4 **Q. How are multiyear rate plans typically constructed?**

5 **A.** MYRPs have the following common characteristics.

- 6 • A moratorium is placed on general rate cases. Rate cases are typically held
7 every three to five years, but plan terms of eight and ten years have been
8 approved.
- 9 • There is usually a need for the revenue of a utility to grow between rate
10 cases since its costs tend to grow for reasons that include demand growth,
11 input price inflation, and a need to modernize facilities. In an MYRP a
12 revenue adjustment mechanism (“RAM”) compensates the utility for some
13 cost pressures between rate cases without closely tracking the utility’s
14 actual cost growth.
- 15 • Costs that are difficult to address with the RAM may instead be accorded
16 tracker treatment. Energy commodity costs are most commonly tracked.

- Revenue adjustments are typically permitted for events that affect utility finances, are largely beyond the utility’s control, and difficult to foresee. These events are sometimes said to be “Z factored.” Events that are commonly eligible for Z factoring include major storms, changes in accounting standards, transportation system construction, and changes in tax laws or regulatory policies.
- MYRPs often also include service quality metrics and PIMs.

A number of other provisions are sometimes added to MYRPs, including the following.

- Revenue decoupling is a component of many MYRPs.
- Many plans have additional performance metrics and PIMs.
- Some MYRPs feature an earnings sharing mechanism (“ESM”) that shares surplus and/or deficit earnings with customers when the utility’s rate of return on equity (“ROE”) varies from the commission-authorized target.
- Off-ramp mechanisms may permit reconsideration and possible suspension of an MYRP under pre-specified outcomes such as an unusually high or low ROE.
- Special incentives for underused practices are also found in many MYRPs. For example, costs of DSM are usually tracked and pilot programs are common.
- Some MYRPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services that a utility offers. The optional services that PSE already offers include green power and managed residential EV charging. Provisions like these can help utilities respond to the complex and changing needs of customers and encourage beneficial loads.

Q. How popular is the MYRP approach to regulation?

A. MYRPs have been used in North America since the 1980s. They were first used on a large scale for railroads and incumbent telecommunications carriers. These industries had a particular need for marketing flexibility and achieved rapid

1 productivity growth under MYRPs. The Federal Energy Regulation Commission
2 has used MYRPs for many years to regulate oil pipelines.

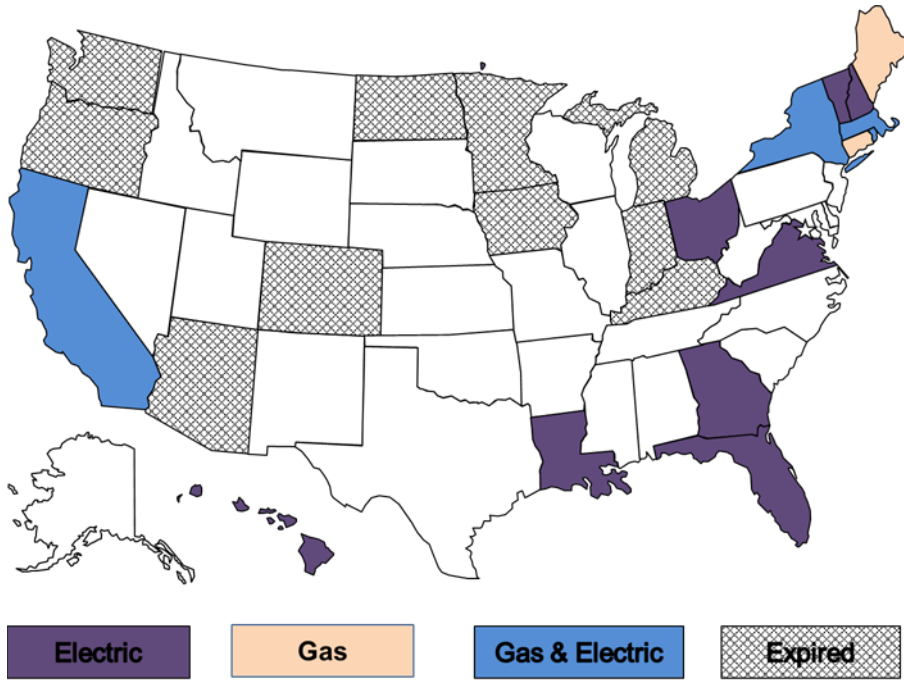
3 MYRPs have also been used on many occasions to regulate retail services of gas
4 and electric utilities. Recent precedents for MYRPs in North America are detailed
5 in the maps below in Figure 2 and Figure 3. In the United States, California
6 utilities have operated under commission-imposed rate plans that limit the
7 frequency of rate cases since the 1980s. MYRPs became popular in some
8 northeastern states (e.g., Maine, Massachusetts, and New York) in the 1990s.

9 MYRPs are now fairly widespread. Today, energy distributors operate under
10 MYRPs in California, Ohio, New York, and New England. Use of MYRPs has
11 also spread to vertically-integrated electric utilities (“VIEUs”) in diverse states
12 including Arizona, Florida, Louisiana, Minnesota, and Virginia. In addition to
13 Washington, a recent law encourages MYRPs in North Carolina.

14 MYRPs are even more widely used in Canada to regulate energy utilities. British
15 Columbia, Washington’s neighbor province, was an early innovator and recently
16 decided to regulate BC Hydro, a large VIEU, with a MYRP. MYRPs are also
17 common in Alberta, Ontario, and Québec. Overseas, MYRPs are the norm for
18 energy utilities in several English-speaking countries (e.g., Australia) as well as in
19 western Europe.

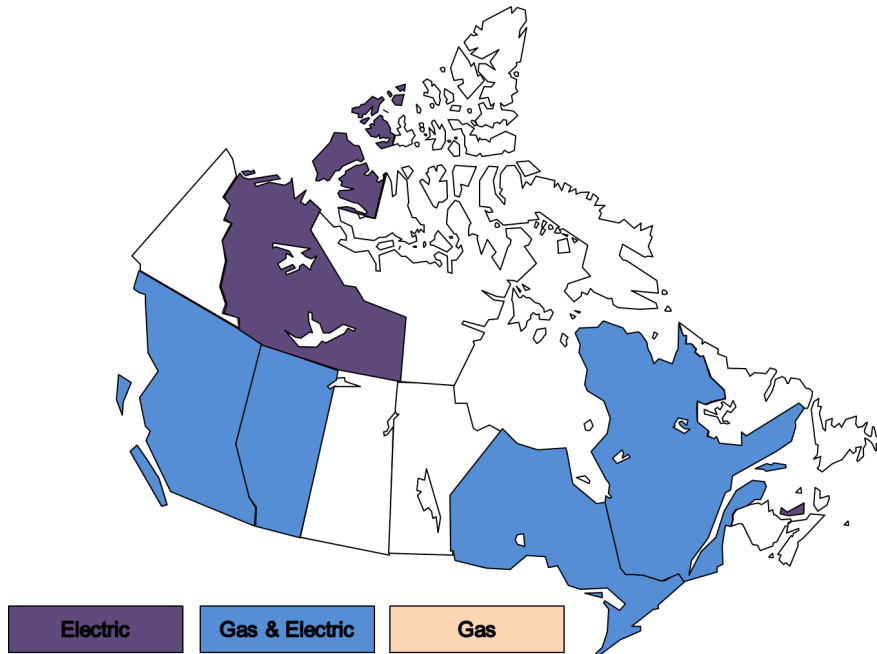
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Figure 2
Recent MYRPs for Energy Utilities in American States



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5
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Figure 3
Recent MYRPs for Energy Utilities in Canadian Provinces



1 **Q. Please discuss the design of revenue adjustment mechanisms.**

2 A. There are several well-established approaches to RAM design.

- 3 • Cost growth can be forecasted over a multiyear period. In MYRPs in
4 Minnesota, New York, and Ontario, forecasts of capital cost growth have
5 been combined with refunds when actual capital cost was less than was
6 forecasted.
- 7 • Revenue growth can be indexed to customer growth and inflation. This
8 approach is especially popular for energy distribution.
- 9 • Rates (or revenue per customer) can be frozen, with supplemental revenue
10 permitted for the annual cost of plant additions.
- 11 • Hybrid revenue caps feature a mix of these basic approaches. California is
12 a well-known practitioner.

13 **Q. How are performance metrics used in utility regulation?**

14 A. Performance metrics quantify aspects of utility operations which matter to
15 customers and the public. A performance metric system can routinely monitor
16 select metrics and use them in performance appraisals. These systems usually
17 include a mix of PIMs, metrics with targets, and tracker metrics. Scorecards
18 summarizing results for key metrics are often tabulated and posted on a publicly-
19 available website.

20 **Q. What are the advantages of metrics and PIMs?**

21 A. Metrics and PIMs have innate advantages in ratemaking.

- 22 • PIMs can strengthen financial incentives to perform better in targeted
23 areas that matter to regulators, customers, and the general public. Even in
24 the absence of explicit financial incentives, utilities have some incentive to
25 perform well in areas where there are metrics because they can garner
26 valuable goodwill from regulators and the public.

- 1 • Metrics and PIMs have been found particularly useful in addressing weak
2 spots in regulatory system incentives. For example, many observers
3 believe that a salient weak spot in most energy utility ratemaking systems
4 is a lack of incentives to contain environmental damage. For instance,
5 although there is significant concern about greenhouse gas (“GHG”)
6 emissions, absent some form of carbon tax or GHG regulation, there has
7 been little incentive to address them. Other parties will be concerned about
8 the terms of service to low-income and other disadvantaged groups in the
9 service territory. PIMs can help align utility regulation with public policy
10 goals.

11 Incentive weak spots can exist even in systems that contain other PBR
12 mechanisms. One reason is that other PBR provisions can sometimes create
13 undesirable incentive “side effects” that metrics and PIMs can address. For
14 example, the stronger incentives that MYRPs can engender to contain the cost of
15 base rate inputs may raise concerns about the quality of utility services. Service
16 quality PIMs are a useful complement.

- 17 • Metrics and PIMs are also useful for alerting utilities to key concerns of
18 regulators and stakeholders, such as chronically poor performance in a
19 certain area.
- 20 • The array of metrics can evolve as new performance concerns arise and
21 some older concerns recede.
- 22 • PIMs can reduce the need for traditional prudence oversight. For example,
23 reliability PIMs can reduce (but probably not eliminate) the need to spend
24 time on formal reviews of reliability.
- 25 • Other means of strengthening incentives and/or reducing regulatory cost
26 are sometimes less feasible. For example, incentivizing energy cost
27 containment with only a partial passthrough tracker can be risky because
28 these costs are volatile. A PIM for energy efficiency programs is an
29 alternative.

30 **Q. What are some of the challenges encountered in PIM design?**

31 A. Performance is often difficult to measure accurately, for several reasons.

- 1 • The outputs from some utility activities are hard to quantify. An example
2 is the load savings from utility efforts to encourage development of
3 markets for DSM products and services.
- 4 • Some metrics (e.g., reliability, delivery volumes, and peak loads) are
5 sensitive to external business conditions, and these conditions are
6 sometimes volatile. The utility is not then fully responsible for their metric
7 values. The impact of external business conditions on performance metrics
8 may be unclear and/or complicated.
- 9 • Standardized data on metrics and business conditions that affect them are
10 often unavailable for numerous utilities. These problems can make it
11 difficult to base performance targets for many metrics on operating data
12 from other utilities.

13 It can also be difficult to correctly *value* performance and establish appropriate
14 award/penalty rates for PIMs. For example, the value of improved service quality
15 or reductions in carbon emissions can be difficult to quantify. Even where the
16 value of improved performance is clear, the share of benefits that utilities should
17 receive may not be. Customer interests are disserved if awards exceed those
18 needed to incentivize good behavior. The appropriate PIM may have a nonlinear
19 form, so that award and penalty rates should rise or fall with measured
20 performance.

21 The design and operation of PIMs can invite controversy and strategic behavior
22 by parties to regulation. For example, controversy has sometimes arisen over the
23 load impact of DSM programs that are addressed by PIMs. Utilities typically
24 resist PIMs with penalty provisions while other parties resist PIMs with reward
25 provisions.

1 The incremental regulatory cost of adding several metrics and PIMs to a
2 regulatory system can be non-negligible. A performance metric system can in
3 principle grow so large and complex as to constitute an undue administrative
4 burden.

5 **Q. Do these considerations have consequences for real-world PIMs?**

6 A. Yes. PIMs tend to be limited to situations where parties are really concerned
7 about performance. Awards are often modest and sometimes capped. Some
8 metrics in a performance metric system will have targets but no PIMs. Tracker
9 metrics are common.

10 The need for PIMs tends to be greater to the extent that the regulatory system
11 otherwise has weak incentives. For example, the need for energy efficiency PIMs
12 is greater in the absence of revenue decoupling. PIMs also tend to be used where
13 they are easy to develop and administer.

14 Complex calculations are often eschewed in PIM design. For example, the award
15 and penalty rates of service quality PIMs rarely reflect sophisticated calculations
16 of the costs or benefits of changes in quality. The California Public Utilities
17 Commission abandoned the complicated shared savings approach to the
18 calculation of awards for DSM programs. Utilities instead receive a share of DSM
19 expenses as a management fee.

1 Some PIMs have dead bands or permit adjustments for the impact of external
2 business conditions. For example, reliability metrics used in PIMs usually exclude
3 major event days (“MEDs”) because these days are typically the result of
4 unusually severe weather or other extraordinary events.

5 **Q. What are some popular uses of PIMs?**

6 A. Service quality is probably the most common area of utility operations addressed
7 by metrics and PIMs. Service quality metrics for energy utilities have traditionally
8 fallen into three general categories: reliability, customer service, and safety.
9 Service quality PIMs can strengthen incentives to maintain or improve quality and
10 simulate the connection between revenue and product quality that firms in
11 unregulated markets experience.

12 Demand side management PIMs have also been popular. These typically reward
13 the utility for success in its energy efficiency (“EE”) programs. The focus is on
14 the load savings attributable to EE and a PIM can strengthen utility incentives to
15 embrace EE. Although decoupling can remove the throughput incentive that
16 discourages EE, a well-designed PIM can provide an additional *positive* incentive
17 that is needed because EE reduces capex opportunities or because costs that might
18 be saved due to EE are external to the company’s finances.

1 **Q. Has interest in PIMs been growing?**

2 A. Yes. Growing interest in PIMs has been spurred in part by Great Britain's "RIIO"
3 approach to MYRP design. The term RIIO stands for "Revenue = Incentives +
4 Innovation + Outputs." The RIIO system features MYRPs with elaborate and
5 innovative arrays of metrics, PIMs, and targeted incentives for underused
6 practices.

7 Performance metric systems are evolving to meet new industry challenges. For
8 example, severe storms and wildfires in some states has spurred interest in
9 resiliency metrics and PIMs. PIMs that address special concerns of policymakers
10 are sometimes called policy PIMs. Policy PIMs often asymmetrically feature only
11 rewards for good performance.

12 **Q. Does this Commission already have some experience with PBR?**

13 A. Yes, the Washington Utilities and Transportation Commission ("UTC" or "the
14 Commission") has experience with all four kinds of PBR and much of this
15 experience is in its regulation of PSE. The Company has previously operated
16 under MYRPs for its electric and gas services on two occasions. It has for many
17 years had an extensive set of service quality metrics and PIMs. PSE has twice
18 operated for several years under revenue decoupling. The Company had an energy
19 efficiency PIM prior to the resumption of decoupling. The Commission's
20 experience with PBR increases the chances that they will oversee its expanded use
21 in Washington effectively.

1 As for targeted incentives for underused practices, the Company’s DSM expenses
2 have long been tracked, and PSE has had several pilot programs. In addition,
3 House Bill 1853 of 2015 authorizes an incentive rate of return of up to 2% on
4 utility investments in electric vehicle supply equipment. The Clean Energy
5 Transformation Act (“CETA”) permits utilities to defer and earn a return on the
6 costs of power purchase agreements in their clean energy action plans.

7 **IV. THE COMPANY’S MYRP PROPOSAL**

8 **Q. What laws are pertinent to the design of an MYRP in the state of**
9 **Washington?**

10 A. SB 5295 requires gas and electric utilities to propose MYRPs in their rate cases. It
11 also established MYRP guidelines, including the following.

- 12 • For each year of an MYRP, the Commission shall ascertain and determine
13 “the fair value for rate-making purposes of the property of any gas and
14 electrical company that is or will be used and useful under RCW
15 80.04.250 for service” along with “the revenues and operating expenses
16 for ratemaking purposes.”¹

- 17 • The Commission is accorded substantial flexibility in the approval of plan
18 details. Subsection 2(3)(d) of the law states, for example, that

19 [i]n ascertaining and determining the fair value of property of a gas or
20 electrical company pursuant to (b) of this subsection and projecting the
21 revenues and operating expenses of a gas or electrical company
22 pursuant to (c) of this subsection, the commission may use any
23 standard, formula, method, or theory of valuation reasonably
24 calculated to arrive at fair, just, reasonable, and sufficient rates.

- 25 • Plans must have a particular kind of ESM. All earnings more than 50 basis
26 points above allowed levels shall be deferred “for refunds to customers or

¹ SB 5295 Sec. 2.3(b) and (c).

1 another determination by the commission in a subsequent adjudicative
2 proceeding.”²

- 3 • The Commission must determine a set of performance measures that will
4 be used to assess a gas or electrical company operating under an MYRP.
- 5 • The term of the plan may be as long as four years. A utility is bound by
6 the terms of the plan in years one and two but may file for new terms to be
7 effective beginning in year three or in any fourth year of a rate plan.
- 8 • Plans must also have provisions for low-income customers which include
9 a discount rate for these customers as well as grants and other low-income
10 assistance programs.

11 In addition, SB 5295 requires the UTC to conduct a proceeding to develop a
12 policy statement on alternatives to COSR which includes “performance measures
13 or goals, targets, performance incentives, and penalty mechanisms.” The
14 Commission has proposed a schedule for this proceeding under which metrics
15 would be addressed first, and a policy statement on metrics is to be issued in
16 March 2023. A policy statement on PIMs is to be issued in December 2024.

17 **Q. Have any policies established by the Commission been considered in the**
18 **development of the Company’s MYRP proposal?**

19 A. Yes. In Docket U-190531 the UTC established a policy concerning the
20 ratemaking treatment of utility assets that are expected to become used and useful
21 after the rate effective date of an MYRP. The Commission permits provisional
22 recovery in rates of the cost of such rate-effective period property. However, this
23 revenue may be reviewed and refunded to customers if the Commission later

² SB 5295 Sec. 2 (6).

1 determines that the assets are not used and useful or that the cost of the assets is
2 not known and measurable, adequately matched to offsetting factors, or prudently
3 incurred. If identified investment costs exceed the amount the regulated company
4 is collecting from customers based on its proposed, estimated, or projected costs,
5 the Company may file an accounting petition.

6 **Q. Please provide an overview of the Company's MYRP proposal.**

7 A. The Company's proposed MYRP is detailed in the Prefiled Direct Testimony of
8 Jon A. Piliaris, Exh. JAP-1T. Some salient features of PSE's proposed MYRP
9 include:

- 10 • Initial rates would be established in this proceeding.
- 11 • Escalation of base revenue would be driven for two years by the
12 Company's latest five-year financial plan. This five-year financial plan is
13 detailed in the Prefiled Direct Testimony of Joshua A. Kensok, Exh. JAK-
14 1T. Of the various approaches to RAM design that I discussed above, this
15 one is most consistent with RCW 80.28.425(3) parts (b) and (c).
- 16 • The portion of the Company's proposed rate increases that is tied to
17 projections of the costs of assets that are expected to become used and
18 useful during the plan is subject to refund pending a Commission review.
19 This provision is consistent with the Commission's decision in Docket U-
20 190531 and other jurisdictions whose MYRPs have been approved.
- 21 • Revenue would be subject to an adjustment for unforeseen inflation.
- 22 • Revenue decoupling would continue for gas and electric services to
23 residential and most commercial and industrial customers; this is vitally
24 important to encourage DSM and supportive rate designs.
- 25 • Any surplus earnings, defined as those which would cause the Company's
26 rate of return on rate base ("ROR") to exceed its authorized target by more
27 than 50 basis points, would be deferred for refunds to customers or
28 another determination by the Commission in a subsequent proceeding.

- There are various provisions to assist highly impacted communities (“HIC) and vulnerable populations (“VP”), including a special rate for low-income customers.
- There is a shortlist of performance metrics and PIMs that are particularly appropriate for tracking PSE’s performance and encouraging good performance. Results would be posted on a publicly-available MYRP scorecard. Additional metrics on various topics will continue to be reported routinely by PSE in other venues.
- Unless the Company exercises the right to request a new plan prior to year three, the plan will have a term of three years.

V. PERFORMANCE METRICS AND PIMS IN THE PSE PROPOSAL

A. Development of PSE’s Performance Metrics and PIMs

Q. How were the performance metrics and PIMs in the PSE MYRP developed?

A. In developing the performance metrics and PIMs in the Company’s proposed MYRP, PSE was guided by applicable legislation, including the CETA. PSE also considered the criteria itemized in SB 5295 for evaluating metrics and other PBR plan provisions. Those criteria emphasize environment and equity considerations as well as the more traditional regulatory concerns about cost and reliability.

PSE also considered that the Commission is undertaking a generic proceeding to develop policies concerning metrics and PIMs. The Company intends that its proposal and supportive evidence on the MYRP, metrics, and PIMs will help to inform the Commission on these issues. This evidence is not, however, intended to supplant the UTC’s effort to fashion PBR policies. Cautious steps in the development of PIMs seem warranted until the Commission’s generic proceeding

1 advances. The Commission’s generic proceeding may lay the foundation for new
2 metrics and PIMs in the Company’s subsequent MYRPs.

3 The development of the proposed metrics and PIMs was also influenced by PEG’s
4 appraisal of weak spots in the incentives included in typical utility regulatory
5 systems. Another consideration was the input obtained from collaboration with
6 UTC staff and stakeholders.

7 **Q. Please discuss the metrics collaborative.**

8 A. PSE established a collaborative process to exchange ideas with stakeholders about
9 metrics and PIMs for its MYRP. Participants in this process included the Alliance
10 of Western Energy Consumers, Climate Solutions, the Energy Project, the NW
11 Energy Coalition (“NWECC”), Public Counsel, and UTC staff. Four meetings were
12 held between August 20 and November 15 of 2021. PSE presented detailed draft
13 metrics and PIMs in a meeting on October 8. NWECC presented a proposal that
14 included PIMs in several areas, such as demand response, equity, and
15 transportation electrification, in the meeting on November 15.

16 Notable takeaways from discussions with stakeholders included the following.

- 17 • Some stakeholders wanted to discuss PIMs and metric-target pairings, not
18 just lists of metrics.
- 19 • Metrics and PIMs should target identified problems that require attention.
- 20 • Consumer groups questioned the need for PIMs with rewards.
- 21 • Several stakeholders espoused the view that PSE should not be rewarded
22 for things that the Company is already incented or required to do.

1 Incentives should encourage “new or improved programs and services that
2 utilities would not otherwise pursue.” There should be a “rigorous
3 baseline setting” and a “high bar of additionality.”

4 **Q. Please summarize the performance metrics and PIMs in the Company’s**
5 **proposed MYRP.**

6 A. The proposed metrics and PIMs are summarized in Table 1 below. A scorecard
7 containing the proposed metrics is detailed in Table 2. This scorecard contains
8 historical values for the metrics where they are available, and it also includes any
9 targets or baselines that are proposed. Details of the metrics and targets are
10 provided in Exh. MNL-4. In addition to service quality, metrics are proposed in
11 the areas of affordability, demand response, energy efficiency, electric vehicles,
12 greenhouse gas emissions, and advanced metering infrastructure (“AMI”). In
13 keeping with the equity goals of CETA, analogous metrics are reported in these
14 areas for highly impacted communities (“HIC”) and vulnerable populations
15 (“VP”) where practical. Policy PIMs are proposed in two areas where NWECC
16 made proposals, although the specifics of the PSE and NWECC proposals differ.

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Table 1
Overview of Proposed Metrics and PIMs

		Systemwide	Highly-Impacted Communities and Vulnerable Populations
Customer Cost and Affordability	Affordability		Number of low income customers receiving bill assistance Share of bill assistance customers who are in highly impacted and vulnerable communities
		Demand-Side Management	
	Environmental Impact	Peak Load Management Savings (PIM) Peak load management savings attributable to residential customers Annual energy efficiency savings (electric and gas)	Number of customers participating in gas and electric energy efficiency programs from highly impacted communities and vulnerable populations
		Electric Vehicles	
		Number of Residential and Fleet EV Chargers Used in Managed Charging Programs or TOU Rates (PIM) Number of light-duty electric vehicles	Number of public charging ports serving highly impacted communities and vulnerable populations
	Greenhouse Gas Emissions		
		CO2 emissions from company-owned electric operations	
	Advanced Metering Infrastructure		
		Reduced energy consumption from voltage reduction Remote switch success rate AMI bill read success (gas and electric)	
	Service Quality & Safety	Safety SQIs (several metrics, some PIMs)	
Customer Satisfaction SQIs (several metrics, some PIMs)			
Customer Service SQIs (several metrics, some PIMs)			
Field Operations SQIs (several metrics, some PIMs)			
Electric Service Reliability SQIs (several metrics, some PIMs)			
		Revised SAIDI and SAIFI metrics for non-storm days	SAIDI and SAIFI metrics in highly impacted communities and vulnerable populations

Note: Items in bold text include PIMs

1
2

**Table 2
Proposed PSE Scorecard**

Current SQI Metrics								
Category	Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Customer Satisfaction	Complaints per 1,000 Customers to the WUTC	0.18	0.2	0.16	0.16	0.1		Less than 0.4
	Customer Access Center Transactions Customer Satisfaction	93%	93%	94%	92%	94%		At least 90%
	Field Service Operations Transactions Customer Satisfaction	95%	94%	95%	95%	96%		At least 90%
Customer Service	Calls Answered by a Live Representative Within 60 Seconds of Request*	82%	82%	81%	81%	84%		At least 80%
	Percent of Appointments Kept	100%	100%	100%	100%	99%		At least 92%
Gas Safety	Average Gas Safety Response Time	31 minutes	32 minutes	30 minutes	32 minutes	32 minutes		No more than 55 minutes
Electric Safety	Average Electric Safety Response Time	55 minutes	55 minutes	52 minutes	54 minutes	51 minutes		No more than 55 minutes
Electric Reliability	SAIFI All Outages Current Year (SAIFI _{ALL})	1.70 Interruptions	1.80 Interruptions	1.57 Interruptions	1.57 Interruptions	1.70 Interruptions		No Target
	SAIFI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days (New SAIFI _{EX-4})	1.00 Interruptions	1.12 Interruptions	0.99 Interruptions	0.98 Interruptions	1.04 Interruptions		1.2 Interruptions
	SAIDI All Outages Current Year (SAIDI _{TOTAL})	391 minutes	477 minutes	438 minutes	550 minutes	414 minutes		No Target
	SAIDI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days (SAIDI _{EX-3})	148 minutes	175 minutes	145 minutes	136 minutes	165 minutes		155 minutes
New SQI Metrics								
Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target	
SAIFI for HIC and VP, All Outages, Single Year	1.12	1.31	1.13	1.18	1.35		No Target	
SAIFI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	0.75	0.88	0.77	0.74	0.84		No Target	
SAIDI for HIC and VP, All Outages, Single Year	249	331	351	427	340		No Target	
SAIDI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	105	143	116	111	141		No Target	
Demand-Side Management								
Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target	
Peak Load Management Savings (MW)	N/A	N/A	N/A	N/A	N/A		5	
Peak Load Management Savings (MW) Attributable to Residential Customers	N/A	N/A	N/A	N/A	N/A		No Target	
Annual Energy Efficiency Savings - Electric (MWh)	314,526	318,316	299,918	237,925	221,001		239,026	
Annual Energy Efficiency Savings - Gas (Therms)	4,480,141	3,613,600	3,771,307	3,228,159	4,102,810		3,572,307	
Number of Customers Participating In Gas and Electric Energy Efficiency Programs (Including Low-Income Programs) Who are from Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target	
Electric Vehicles								
Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target	
Number of Light-Duty Electric Vehicles In Service Territory	NA	NA	NA	NA	NA		No Target	
Number of EV Chargers Used In Managed Load Programs or TOU Rates (Single-Family Residential)	NA	NA	NA	NA	NA		5,000	
Number of EV Chargers Used In Managed Load Programs or TOU Rates (Fleet)	NA	NA	NA	NA	NA		47	
Number of Public Charging Ports Serving HIC and VP	NA	NA	NA	NA	NA		No Target	
Greenhouse Gas Emissions								
Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target	
CO2 Emissions from Company-Owned Electric Operations	6,515,902	6,217,840	6,080,674	7,406,110	4,793,992		No Target	
Advanced Metering Infrastructure								
Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target	
AMI Bill Read Success Rate - Electric	NA	NA	NA	99.68%	99.76%		No Target	
AMI Bill Read Success Rate - Gas	NA	NA	NA	99.40%	99.43%		No Target	
Remote Switch Success Rate	NA	NA	NA	NA	99.41%		No Target	
Reduced Energy Consumption from Voltage Reductions (kWh)	3,319,625	0	2,127,882	343,748	3,931,329		6,000,000	
Additional Equity Metrics								
Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target	
Number of Low-Income Customers Receiving Bill Assistance (Gas and Electric)	NA	NA	NA	NA	NA		No Target	
Share of Bill Assistance Customers who are In Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target	

Values of "NA" indicate that historical data are not readily available. "No target" indicates that no target has been established for that metric in that year.
*In 2016 and 2017 this metric was the percentage of calls answered in 30 seconds. The target for this metric was 70%. The data reported for these years are consistent with the current metric.

1 **Q. Please discuss the service quality indicators.**

2 A. Service quality metrics and PIMs are a standard feature of MYRPs. The Company
3 already has numerous service quality indicators (“SQIs”). Many of the SQIs have
4 targets and some are linked to PIMs. Compensation of PSE employees is tied to
5 SQI outcomes.

6 The Company is proposing some changes to its reliability metrics in this
7 proceeding. SAIDI and SAIFI metrics would be computed using only the latest
8 (2012) IEEE-1366 methodology for removing major event day outages. The
9 Company is also proposing its SAIFI metric be calculated similarly to the current
10 SAIDI metric, using the IEEE-1366 methodology with adjustment for
11 catastrophic events. To ensure comparability with past Company values for these
12 SQI metrics, the baseline values would be calculated beginning in 2014, a year
13 subsequent to PSE’s implementation of its Outage Management System and
14 Customer Information System.

15 These reliability metrics would be separately reported for the system as a whole
16 and for highly impacted communities and vulnerable populations. Reliability
17 tends to be higher in highly impacted communities and vulnerable population
18 areas. However, no targets are proposed for these metrics. Additional discussion
19 of the new reliability SQIs can be found in the Prefiled Direct Testimony of
20 Catherine A. Koch, Exh. CAK-1T.

1 **B. Demand Side Management Metrics**

2 **Q. Please discuss DSM metrics.**

3 A. DSM should play a major role in meeting PSE's and Washington's
4 decarbonization goals. In the short term, DSM can reduce the need for fossil fuels.
5 In the longer term, it can reduce the need for cleaner but more costly energy
6 alternatives. For these reasons, DSM figures prominently in the Company's Clean
7 Energy Implementation Plan ("CEIP").

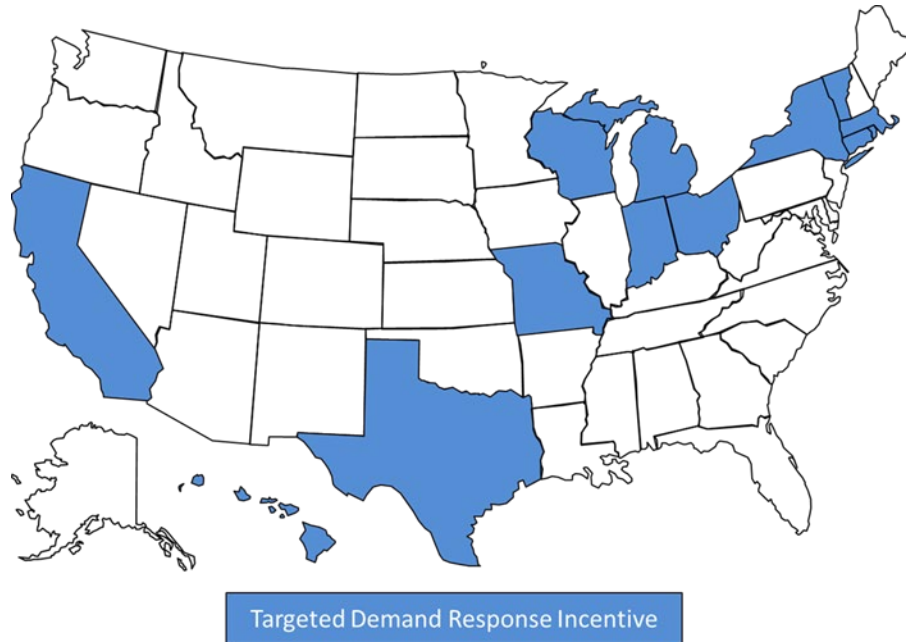
8 Revenue decoupling can reduce the throughput disincentive to embrace DSM and
9 rate designs that encourage it. There are also strong arguments and many
10 precedents for supplementing revenue decoupling with PIMs and other "positive"
11 incentives for utilities to embrace DSM.

12 In addition to PIMs for energy efficiency, there is growing national interest in
13 metrics and PIMs that encourage load shaping programs. The need for load
14 shaping is growing with increased reliance on renewable resources, which have
15 intermittent availability that typically doesn't peak when demand does.

16 Electrification of transportation and space heating can strain system capacity but
17 can also absorb power surpluses when renewable resources are abundant. In parts
18 of the United States, reduction of systemwide peaks can also reduce the share of
19 regional transmission costs that are assigned to a utility.

1 At least 13 U.S. jurisdictions have PIMs or other targeted incentives to reduce
2 system peak demand. These jurisdictions are depicted in the map in Figure 3
3 below.

4 **Figure 4**
5 **Targeted Incentives for Electric Peak Load Management³**



7 Incentives in these PIMs are, variously, based on:

- 8
- 9 • sharing of estimated net benefits of demand response (“DR”) programs;
 - 10 • return on program expenses;
 - 11 • compensation for foregone earnings on avoided investments; or
 - a pre-established dollar amount or management fee.

³ Gold, R., Myers, A., O’Boyle, M., and Relf, G. (2020), “Performance Incentive Mechanisms for Strategic Demand Reduction”, p. 10.

1 The reward is typically contingent on meeting or exceeding a threshold level of
2 DR. These PIMs sometimes incorporate capacity savings from EE programs or
3 are complemented by an energy efficiency PIM.

4 **Q. Are some Washington statutes pertinent when considering the need for PSE**
5 **to have DSM PIMs?**

6 A. Yes. For example, the Energy Independence Act requires large investor-owned
7 electric utilities to “pursue all available [electric] conservation that is cost-
8 effective, reliable, and feasible.”⁴ A similar mandate applies to gas conservation.⁵
9 The CETA includes a mandate “to pursue all cost-effective, reliable, and feasible
10 conservation and efficiency resources, and demand response”.⁶

11 In addition, the CETA requires that all customers benefit from the transition to
12 clean energy. Burdens to vulnerable populations and highly impacted
13 communities should be reduced. Utilities must routinely report information on the
14 energy burden and energy programs for disadvantaged customers. The CEIPs that
15 utilities have developed pursuant to CETA have included customer benefit
16 indicators (“CBIs”).

17 In the collaborative, some stakeholders opposed demand-side management PIMs
18 on the grounds that the Company has these legislative mandates to pursue cost-
19 effective conservation and peak load management. However, NWECA did propose

⁴ See, RCW 19.285.040(1).

⁵ See, RCW 18.28.380.

⁶ See, RCW 19.405.050(3).

1 a DR PIM. The metrics in the NWECA-proposed DR PIM were MW of demand
2 reduction from residential customers and the entire portfolio, winter and summer.

3 **Q. Is PSE proposing a demand response PIM?**

4 A. Yes. The Company is proposing an annual metric, target, and PIM to encourage it
5 to obtain DR resources. Eligible DR programs would include direct load control
6 (“DLC”), interruptible (curtailable) load, and/or pricing programs designed to
7 shift load from peak periods and reduce system peak demand. In Chapter 4 of its
8 recently-filed CEIP, PSE explained that it would acquire DR resources primarily
9 through its Distributed Energy Resources / Demand Response Request for
10 Proposal (“DER / DR RFP”), which the Company anticipates filing in early 2022.
11 However, DR resources procured through PSE’s own efforts — outside of the
12 competitive procurement process — would also be included.

13 **Q. Would there be any exception to the DR resources eligible for this PIM?**

14 A. Yes. To prevent double-counting of payments, any EV loads that qualify for the
15 EV PIM explained later in my testimony would be excluded from the
16 achievement levels used to establish performance under the DR PIM.

17 **Q. What is the proposed metric for DR?**

18 A. The specific metric to be tracked for DR would be the expected MW reduction in
19 the Company’s need for planning reserves for the winter coincident peak demand.
20 Effective DR capacity is a useful shorthand expression for this concept. Each

1 program's effective capacity would be estimated based on pre-established
2 measurement and verification techniques, consistent with any relevant approaches
3 PSE provides in its CEIP.

4 **Q. What are the proposed targets for DR?**

5 A. PSE proposes annual incremental effective capacity targets of 5 MW in 2023, 6
6 MW in 2024, and 12 MW in 2025. These goals mirror those proposed in the
7 Company's CEIP. Since the Company currently realizes no peak demand
8 reductions through DR programs, these proposed targets represent a significant
9 improvement.

10 **Q. What do you mean by incremental DR capacity in a given year?**

11 A. Suppose a new DLC program is initiated in 2023 and is expected to have the
12 capacity to reduce winter coincident peak demand by 3 MW. The DLC program
13 would then contribute 3 MW towards the Company's 2023 DR achievement level.
14 If the Company added 2 MW of effective capacity through the same program in
15 2024, that 2 MW would count towards the 2024 DR achievement level.

16 **Q. Please explain the PIM that the Company is proposing for DR.**

17 A. PSE is proposing a PIM that would provide the Company a percentage of its
18 estimated lifetime cost of developing and administering DR programs, including
19 the costs of developing and administering the DER / DR RFP. The Company
20 would receive a payment only if it achieved at least 90 percent of its incremental

1 annual effective DR capacity target. The payment percentage would be 15 percent
2 for achievement levels of 90 percent through 110 percent of the annual target.
3 This percentage would increase to 25 percent for achievement levels over 110
4 percent and up to 150 percent of the target. No additional reward would be
5 provided for achievement levels in excess of 150 percent of the target. More
6 details regarding the Company's proposed demand response PIM are provided in
7 Exh. MNL-5.

8 **Q. Are the payment percentages of 15 percent and 25 percent reasonable?**

9 A. Yes. Establishing specific payment percentages is ultimately a matter of
10 judgment. But it is important to remember that one of the justifications for a DR
11 PIM is that the utility is potentially foregoing supply-side investments on which it
12 would earn a return. Moreover, the installed costs of the investment would most
13 likely exceed the DR expenses on which the PIM is based. The proposed PIM
14 should be evaluated with that consideration in mind.

15 If the Company achieves less than 90 percent of its target, it foregoes any
16 earnings opportunity. If the Company achieves at least 90 percent and no more
17 than 110 percent of its target, then it will realize a payment of 15 percent of its
18 expenses, which is roughly twice its weighted average cost of capital ("WACC").

19 The percentage payment should be higher than the WACC because:

- 20 • DR expenses will probably be less than the installed cost of supply-side
21 resources offering similar capacity value;

- 1 • the utility deserves a premium payment if it performs well in an important
2 new policy area, i.e., it should be financially better off than if relied on
3 supply-side resources for the same capacity; and
- 4 • PSE's achievement levels are less certain than they are for most other
5 utilities, since PSE has little historical experience with DR.

6 By extension, if the utility performs very well, i.e., achieves more than 110
7 percent of its target, then it should receive a greater percentage payment to reflect
8 superior performance.

9 The cap on the total payment (at 150 percent of the target) will protect customers
10 by imposing a ceiling on the total payment in any year.

11 **Q. Why is a reward-only PIM appropriate?**

12 A. The DR PIM focuses on a new performance expectation that goes beyond
13 satisfying customers' basic service requirements. In addition, utilities have a
14 financial disincentive to implement DR programs, as they tend to reduce billing
15 determinants, rate base and earnings.

16 **Q. Does PSE propose to establish any additional DR metrics?**

17 A. Yes. In addition to establishing a metric, target and PIM for the total DR impact
18 on the winter system peak demand, the Company also proposes to track separately
19 the residential contribution to this total. There would be no corresponding target
20 or PIM for the residential class.

1 **Q. Why is PSE not proposing a separate target and PIM for the residential**
2 **class?**

3 A. The Company has established CEIP goals for the total impact of DR resources on
4 winter coincident peak demand but has not disaggregated this goal by customer
5 class. At this point there is no adequate basis on which to establish a residential-
6 only target.

7 **Q. Why is the Company proposing a target and PIM for the impact of DR on**
8 **winter coincident peak demand only and not on both summer and winter**
9 **coincident peak demands?**

10 A. For the foreseeable future, PSE expects to remain a winter-peaking utility.
11 Although PSE is not proposing to establish a summer peak load metric at this
12 time, the Company recognizes that higher air-conditioning saturation in its service
13 territory will increase the importance of reducing summer coincident peak
14 demand as well. Consequently, at some point the Company might propose adding
15 a summer metric.

16 **Q. Is PSE proposing any other DSM-related metrics?**

17 A. Yes. PSE is proposing tracker metrics on its scorecard for the incremental energy
18 savings from its gas and electric energy efficiency programs. These data are
19 routinely reported in other Company filings. Targets have been established for
20 these metrics.

1 The number of distinct residential and commercial customers participating in
2 electric and gas EE programs who are members of highly impacted communities
3 or vulnerable populations would also be reported. In this calculation, EE
4 programs open to the general public would be counted as well as those that focus
5 on low-income customers. No target is proposed for this metric.

6 **C. Transportation Electrification Metrics**

7 **Q. Please discuss the transportation electrification metrics.**

8 A. The transportation sector is the largest source of GHG and hazardous pollutants
9 (e.g., nitrogen oxide) in Washington. These emissions harm the environment and
10 some also degrade visibility and human health. Transportation electrification is
11 accordingly a key goal of the State's clean energy initiative. Detrimental health
12 impacts from nitrogen oxide and particulate vehicle emissions are greatest in the
13 Seattle-Tacoma transportation corridor that PSE serves.

14 Electric utilities reduce these problems when power generated from clean
15 resources displaces combustion of petroleum products in transportation (and
16 various other kinds of) equipment. Under traditional ratemaking, utilities have
17 some incentives to promote such beneficial electrification. In the short run,
18 electrification can sometimes boost the utilization of excess capacity and thereby
19 create margins from load growth between rate cases. Mobile phone providers
20 have similar incentives to sign customers to service plans and these carriers have

1 a high profile in advertising. In the longer run, electrification can also bolster the
2 need for utility grid investments that enhance earnings.

3 As described below, utilities nonetheless do not always have strong incentives to
4 aggressively promote beneficial electrification.

- 5 • Revenue decoupling promptly passes any margins from electrification to
6 customers.
- 7 • Utilities incur costs when EV charging on customer premises increases.
8 These costs may include those for electric vehicle supply equipment such
9 as chargers and other infrastructure upgrades. The costs of EV load growth
10 can also include those for marketing, load management, and customer
11 support. Marketing costs may include discounts on the cost of special
12 services required to support EVs. The cost and hassles of encouraging and
13 then providing service to an additional EV are higher for the medium and
14 heavy-duty vehicles that account for a disproportionately large share of
15 hazardous transportation pollutants.
- 16 • EVs must sometimes be charged outside of customers' premises at
17 commercial charging stations. The cost to design, permit, site, construct,
18 own, operate, and maintain these stations is substantial and may not be
19 covered by the resultant revenue. Unprofitable charging stations will be a
20 particular problem in the next few years while the number of EVs on the
21 road is ramping up but potential customers seek assurance that sufficient
22 charging capacity will be available. The utility may get stuck with some of
23 the less profitable locations.
- 24 • Even if the utility's forecasted revenue requirement includes a budget for
25 utility EV costs, the growth in this revenue requirement component is
26 disconnected from the growth that actually occurs unless the cost is
27 tracked. Moreover, there will be no funding for EV load growth that
28 exceeds the amount forecasted.
- 29 • In the presence of revenue decoupling, the addition of a public charging
30 station or an EV load on customer premises may therefore impose a
31 marginal cost on the utility without corresponding marginal revenue. This
32 weakens the incentive of the utility to support EV load growth. The utility
33 may respond by scaling back marketing efforts, reducing discounts, or by
34 limiting the number of customers that can access its EV services.

- The inclination of a utility not to encourage and support EV growth will be greater the greater are its cost-containment incentives. This problem can be mitigated by tracking the cost of EV services for prompt or deferred recovery. This cost has heretofore been modest for most utilities.

The incentive problem is exacerbated by the fact that decoupling tends to be popular where EVs are popular (e.g., California and New York). The new law encouraging PBR in North Carolina requires that utility proposals include residential revenue decoupling with the following exception:

The electric public utility may exclude rate schedules or riders for electric vehicle charging, including EV charging during off-peak periods on time-of-use rates, from the decoupling mechanism to preserve the electric public utility's incentive to encourage electric vehicle adoption.⁷

Q. Have any PIMs been approved for EV's in the United States?

A. Yes. Several PIMs have been approved in New York that encourage electric vehicles and other kinds of beneficial electrification. These have typically taken the form of rewards for estimated GHG savings. These precedents are noteworthy since electric utilities in New York operate under revenue decoupling.

Q. Are there some Washington-specific considerations to take into account when contemplating the need for EV PIMs?

A. Yes. I have already mentioned that Washington law sanctions a modest rate of return premium on utility-owned electric vehicle supply equipment. The Company proposes to embrace this incentive, as discussed in the Prefiled Direct Testimony of William T. Einstein, Exh. WTE-1T. The rising low carbon fuel

⁷ North Carolina House Bill 951, Part II, Section 4 (a) (c) (2), 2021.

1 standard that Washington’s legislature has approved will boost the funding of
2 utility EV programs but the Company’s funds from this source will be modest
3 during the term of the proposed MYRP (2023-25), may only pertain to residential
4 EV customers, and may have restricted uses. Some details of this program have
5 not been finalized.

6 Stakeholders in the collaborative metric discussions nonetheless maintained that
7 PSE has adequate incentives to promote EVs. They did, however, evince concern
8 about the Company’s incentive to manage EV loads cost-effectively. NWECC
9 proposed a PIM for EV load management. The proposed metric was percentage of
10 load shifted to off-peak periods that are attributable to EV tariff offerings.

11 PSE has a well-established program for supporting the growth of EV loads. In this
12 program, the Company typically owns the electric vehicle supply equipment.
13 Loads of many program participants are managed where this is practicable. The
14 principal focus of managed-load programs to date has been single-family
15 residential customers. PSE plans to expand its EV service offerings during the
16 MYRP, and expansion of EV service to commercial customers and disadvantaged
17 communities are priorities. Managed loads for fleet customers appear to be
18 practicable. However, with the Company having many other goals in the next few
19 years, including better reliability, internal funding for EV load management will
20 be limited.

1 **Q. Is the Company proposing any metrics and PIMs in the EV area?**

2 A. Yes. PSE is proposing a PIM for electric vehicle load management and additional
3 EV metrics that are not subject to targets or PIMs. I explain these proposals
4 below.

5 **Q. What metrics and targets is the Company proposing for the EV PIM?**

6 A. The metric is the number of new chargers installed in a given calendar year and
7 used to provide service under either a load management program or time of use
8 (“TOU”) rates, including the Company’s proposed Time Varying Rate (“TVR”) program.
9 In the operation of the PIM the Company proposes metrics and targets
10 for the following types of chargers:

- 11 • Level 2 Chargers used in single family residences;
- 12 • Level 2 Chargers used for fleets; and
- 13 • DC Fast Chargers used for fleets.

14 **Q. Why does the Company propose to establish metrics and targets for three**
15 **categories of charger?**

16 A. As I explain later, the Company’s proposed PIM is based on the expected net
17 benefits of each new installation. These net benefits vary significantly depending
18 on the type of charger (Level 2 or Fast Charger) and its application (single family
19 residence or fleet). Consequently, it is important to track not only the total number
20 of new chargers, but also the number of chargers in each of the three distinct
21 categories.

1 **Q. Would the targets and PIM be limited to Company-owned chargers?**

2 A. No. The benefits of encouraging customers to charge during off-peak periods are
3 not contingent on Company ownership. Consequently, the Company proposes that
4 the targets and rewards be applied to chargers owned by the Company, customers,
5 or third parties. This approach can incentivize the Company to accommodate
6 chargers owned by others.

7 **Q. During which calendar years would the proposed PIM be effective?**

8 A. PSE proposes that the PIM be effective for calendar years 2023, 2024 and 2025.
9 Of course, the Company may later propose an extension of the PIM, either as
10 approved in this proceeding or with modifications. The Commission's decision in
11 this proceeding should be issued before the first year of the PIM (2023).

12 **Q. Is the Company proposing specific targets in its direct case?**

13 A. No. PSE is still in the process of developing its EV charging targets and
14 anticipates that these targets will be established sometime in the first quarter of
15 2022. Once these targets are available, the proposed PIM can be set forth in more
16 detail.

1 **Q. Please explain the conditions under which the Company would earn a**
2 **reward under the proposed PIM.**

3 A. The Company would earn a reward in any given year only if the number of new
4 chargers installed in one or more of the three categories exceeded the target for
5 that category or categories for that year. The reward would be provided only for
6 new installations in excess of the target; in other words, if the target in 2023 was
7 100 chargers and the Company installed 102 chargers during 2023, then the
8 Company would earn a reward only for the two chargers in excess of the target.

9 **Q. Assuming the Company exceeded its target in one or more categories, how**
10 **would the specific dollar amount of the reward be established?**

11 A. The Company proposes that the reward be based on a percentage of the expected
12 net benefits of the chargers eligible for a reward. The gross benefits would consist
13 of the:

- 14 • avoided energy costs,
- 15 • avoided generation capacity costs, and
- 16 • avoided transmission and distribution capacity costs.

17 The expected avoided costs represent the cost impact of the managed load
18 program or TOU pricing on the usage pattern of the chargers. In other words, the
19 avoided costs represent the difference between the cost of serving an EV charging
20 load under a managed load program or TOU rates and the cost of serving the
21 same charger assuming no managed load program or TOU rates.

1 The costs would consist of the *incremental* administrative and other costs that the
2 Company incurs to serve the charging load under a managed load program or
3 TOU rates. The “other costs” would include any incentive payments to customers
4 to encourage them to place their charging loads on managed load programs or
5 TOU rates.

6 I emphasize that these incremental costs would exclude the majority of the costs
7 of developing and administering the load management or TOU pricing option.
8 Instead, the costs used to calculate net benefits would be limited to the
9 incremental costs of serving an additional charger under the load management
10 program or TOU rates.

11 The expected benefits and costs per charger would be estimated over five years.
12 The present value of the five-year stream of costs would then be subtracted from
13 the present value of the stream of benefits to yield a single dollar reward for each
14 installed charger in excess of the target. A distinct dollar award per installation
15 would be established for each of the three categories of chargers.

16 **Q Why do the costs and benefits in the proposed calculations exclude many of**
17 **the impacts of EV load growth, such as the investment cost of the charger or**
18 **the environmental benefits of reducing net carbon emissions?**

19 A. It is important to remember that the purpose of this proposed PIM is not simply to
20 encourage more chargers per se, but to encourage customers that do install
21 chargers to charge during off-peak periods — when energy and capacity costs are

1 lower. As mentioned previously, this usage shift was a priority for stakeholders in
2 the metrics collaborative as well. There are other mechanisms (such as a premium
3 return on equity of 200 basis points for EV-related investments) that encourage
4 the Company to install more chargers. Consequently, the impacts used to establish
5 the reward are limited to the impacts of encouraging off-peak charging. Those
6 impacts do not include the net environmental benefits of reducing the emissions
7 from internal combustion engines or the cost of installing a charger.

8 **Q. Why is it appropriate to use expected net benefits as a basis for the reward?**

9 A. One of the primary advantages of basing the reward on a percentage of net
10 benefits is that customers are expected to benefit when the Company exceeds its
11 target(s) as long as the percentage reward to the Company is less than 100
12 percent.

13 A potential disadvantage of using net benefits is that deriving the actual avoided
14 costs can be very time-consuming and administratively burdensome. Such a
15 derivation would require analyses of actual load shifts and actual avoided costs
16 based on these load shifts. To avoid these potentially high costs, the Company
17 proposes to use pre-established estimates of load shifts and the concomitant
18 avoided costs over a five-year period. I believe any reduction in accuracy
19 attributable to using estimates is outweighed by the increased simplicity and
20 reduced costs of administering the PIM.

1 **Q. Why is a reward-only PIM structure appropriate in this case?**

2 A. The justification is similar to the justification for using a reward-only structure for
3 DR. In both cases the Company is challenged with a new performance
4 expectation that goes beyond satisfying customers' basic service requirements. In
5 addition, in both cases the Company is being encouraged to take steps that tend to
6 reduce rate base and earnings.

7 **Q. You explained how the Company's dollar reward would be based on a**
8 **percentage of expected net benefits. Is the Company proposing a specific**
9 **percentage reward in its direct case?**

10 A. No. As explained previously, the Company will not have targets for EV
11 installations until later in this quarter. Similarly, the Company also anticipates
12 developing later in this quarter the estimated costs and benefits that would be used
13 to establish the award per charger. Until this information is available, the
14 Company cannot calibrate an appropriate percentage. The Company plans to
15 propose specific percentages later in this proceeding, when more information is
16 available.

17 **Q. Are you providing an illustrative example of the proposed EV PIM you**
18 **explain above?**

19 A. Yes. Exh. MNL-5 provides a summary of how the PIM would be developed.

1 **Q. Please summarize the Company's proposed EV PIM.**

2 A. The Company proposes a reward-only PIM based on the number of new EV
3 chargers installed in a given year and used to provide service under either a
4 managed load program or TOU rates. The reward would apply to all installations
5 in excess of the target established for that year and would be based on a pre-
6 determined estimate of lifetime net benefits per charger. Separate targets and
7 rewards would be established for single-family residences using Level 2 chargers,
8 fleets using Level 2 Chargers, and fleets using Fast Chargers. While I explained
9 the conceptual approach and justification of the proposed PIM above, the
10 Company will not be positioned to propose specific targets and sharing
11 percentages until later in the first quarter of 2022.

12 **Q. Please describe the EV tracker metrics the Company is proposing.**

13 A. The MYRP scorecard would report two EV-related tracker metrics. One is the
14 estimated number of light-duty plugin electric vehicles (battery-only or hybrid) in
15 the Company's service territory. This would be calculated using Washington
16 Department of Licensing data on EVs registered in zip code tabulation areas in
17 which PSE offers electric service. The Company also proposes to track the
18 number of publicly-available charging ports in highly impacted communities and
19 vulnerable populations. PSE will continue to report a wider array of EV metrics in
20 other venues.

1 **D. Emissions Metrics**

2 **Q. Please discuss the emissions metrics the Company is proposing.**

3 A. Many industry observers believe that utilities have inadequate incentives to
4 contain their impact on the environment. Metrics can track utility activities that
5 damage the environment. Relevant metrics include emissions of GHGs from
6 utility generation and vehicles, sodium hexafluoride emissions, and natural gas
7 leaks and line losses.

8 PSE is preparing to comply with the decarbonization goals of CETA which call
9 for the retail sales of each Washington electric utility to be GHG neutral by 2030.
10 The Company recently detailed a strategy for achieving this in its CEIP. PSE is
11 proposing to track the metric tons of Scope 1 emissions from Company-owned
12 generation. The year-to-year GHG emissions from the Company's generation are
13 volatile, driven by external business conditions such as weather, the business
14 cycle, and the availability of hydroelectric and other kinds of renewable energy
15 resources. Accordingly, no target or PIM are proposed. The tracking of emissions
16 from PSE-owned generation is discussed further in the Prefiled Direct Testimony
17 of Joshua J. Jacobs, Exh. JJJ-1T.

1 **E. Advanced Metering Infrastructure Metrics**

2 **Q. Please discuss the advanced metering infrastructure metrics.**

3 A. In a period when many utilities are investing sizable sums in AMI and other smart
4 grid facilities, regulators and stakeholders want to know if these facilities are
5 functioning well and well-utilized. Potential benefits from AMI include increased
6 customer participation in load shaping programs such as TOU pricing. The
7 benefits of AMI also include reductions in distribution system voltage, the
8 duration of outages, consumption on inactive meters, unaccounted-for energy use,
9 and meter-reading costs.

10 AMI metrics are monitored in several jurisdictions. These metrics have addressed
11 several dimensions of AMI performance, including AMI functionality, utility cost
12 savings, customer engagement, and environmental and load-management benefits.

13 There are a few precedents for AMI-based PIMs. In New York, for example,
14 Consolidated Edison had a PIM to appraise their AMI customer awareness
15 strategy through customer surveys. In Illinois, Commonwealth Edison has PIMs
16 that address the achievement of reductions in the number of estimated bills,
17 energy consumption on inactive meters, unaccounted for energy, and
18 uncollectible bill expenses.

19 The UTC's decision in the recent Avista rate case indicates that they have an
20 interest in AMI performance metrics.

1 To demonstrate the benefits of AMI, Avista should be required (1) to
2 develop and report further analyses of the use cases: TOU rates, real-time
3 energy use feedback for customers, behavior-based programs, data
4 disaggregation, grid-interactive efficient buildings, CVR or volt/VAR
5 optimization; (2) to craft and report plans for achieving benefits through
6 each of these use cases; and (3) to develop and propose AMI performance-
7 based regulation metrics and measurements that the Commission might
8 apply, and specifically such metrics and measurements for each of these
9 use cases.⁸

10 PSE is in the middle of a systemwide AMI buildout. This makes AMI metrics
11 topical but limits the availability of data. The Company is proposing to include
12 three AMI metrics in its MYRP scorecard. These metrics address the functionality
13 of AMI and its impact on system voltage.

- 14 • Bill Read Success. The most fundamental job of AMI is to automatically
15 forward data on customer billing determinants. The proposed Bill Read
16 Success metric would measure whether the AMI delivers a meter read to
17 PSE's data system, as expected each cycle. This would be calculated
18 separately for gas and electric meters. A 99.5% success rate target is
19 proposed for each plan year beginning in 2024.
- 20 • Remote Switch Success. AMI makes it possible to turn service off and on
21 quickly and without truck rolls. The proposed Remote Switch Success
22 metric would measure the functionality of the switch when a command is
23 made from the command center by PSE. Calculation would be limited to
24 customer-initiated requests. This metric would be reported only for
25 electric service. The proposed target is a 99% success rate beginning in
26 2024.
- 27 • Voltage Reduction. The voltage on a distribution circuit must attain a
28 minimum standard for every customer. AMI improves knowledge of the
29 voltage at which each customer on a distribution circuit is served. This can
30 make it possible to reduce voltage on the circuit at the substation that
31 serves it. The proposed Voltage Reduction metric would measure the
32 reduction in KWh accomplished. The proposed target for 2023 is
33 6,000,000 kWh.

⁸ WUTC (2021), Final Order 08/05, p. 127.

1 No AMI PIMs are proposed. The Company will report additional AMI metrics
2 routinely in other venues. AMI metrics are discussed further by Company witness
3 Catherine A. Koch, Exh. CAK-1T.

4 **F. Additional Equity Metrics**

5 **Q. Please discuss any additional equity metrics.**

6 A. I have already noted the metrics on the scorecard for reliability, public EV
7 chargers, and EE program participation in highly impacted communities and
8 vulnerable populations. The affordability of the Company's service to low-income
9 customers is another key area of concern to policymakers. The Company also
10 proposes two affordability metrics. One is the number of distinct customers
11 receiving bill assistance from qualified low-income programs. The qualifying
12 programs would include the low-income energy assistance program ("LIHEAP"),
13 PSE's Home Energy Lifeline Program ("HELP"), the Salvation Army warm
14 home fund, PSE's proposed arrearage management program, and the proposed
15 bill discount rate. The Company will also report the share of these bill assistance
16 customers who are members of highly impacted communities and vulnerable
17 populations.

18 Customer benefit indicators, many of which have an equity component, will be
19 reported in the annual reporting required under Washington Administrative Code
20 480-100-650(3).

1 **VI. APPRAISAL OF THE COMPANY’S MYRP PROPOSAL**

2 **Q. What are some reasonable criteria for appraising MYRP proposals?**

3 A. An appraisal of a proposed MYRP should encompass several considerations. One
4 is its fairness. A second is its effect on utility performance incentives. A third is
5 its effect on regulatory efficiency. It is also pertinent to consider the extent to
6 which SB 5295 ties the hands of the Commission in approving MYRPs.

7 **Q. Please discuss the fairness of the Company’s proposal.**

8 A. I believe that the Company’s proposal is fair on balance. There are some benefits
9 for PSE. For example, revenue growth would be based on the Company’s
10 financial plan in the two “out” years, as well as the first year, and would be
11 subject to an adjustment for unforeseen inflation. Revenue decoupling would
12 continue to reduce the risk of volatility in billing determinants. Subject to
13 statutory limitations, PSE could file a rate case if it underearns.

14 However, the framework also provides extensive customer protections, including:

- 15 • The Commission would decide the extent to which it would fund PSE’s
16 budgeted cost growth. Moreover, the Company would be obliged to
17 operate under the Commission-approved revenue requirement for at least
18 two years.
- 19 • Revenue to reimburse PSE for the annual cost of capital expenditures it
20 made during the plan may be refunded to customers if the assets are later
21 found not to be used and useful or their cost is deemed imprudent. This
22 provision was noted above to be common to some other approved RAMs
23 that are based on forecasts.
- 24 • The ESM would asymmetrically favor customers. The entirety of weather-
25 normalized earnings in excess of a modest 50 basis point dead band would

1 be reserved for refunds to customers or another determination by the
2 Commission. In contrast, many approved MYRPs have wider dead bands
3 and/or afford utilities a share of surplus earnings beyond the dead band.
4 Some plans do not have an ESM. In the event of underearning, PSE would
5 absorb the entirety of any ROE shortfall until and unless it is granted some
6 rate relief in year three after a rate case. In contrast, in some approved
7 MYRPs underearnings are automatically shared with customers.

- 8 • PSE would absorb the risk of fluctuations in loads for some large-volume
9 customers.
- 10 • Rate growth would be more predictable.
- 11 • The term of the MYRP would only be three years.

12 **Q. Please discuss the impact of PSE's MYRP on cost control incentives.**

13 A. The Company's cost control incentives would be strengthened by the MYRP.

14 Under continued COSR, PSE would be free to file a rate case at any time. Given
15 its need to modernize the grid, improve reliability, and supply cleaner energy, the
16 Company would likely file rate cases frequently. It would likely also continue to
17 be subject to earnings sharing.

18 The proposed MYRP would in contrast provide significant incentives to contain
19 O&M expenses since revenue growth for these kinds of costs is not linked to
20 actual cost growth between rate cases. The Company would absorb the annual
21 cost of any capex overspends.

22 The Company's ability to file a rate case during the MYRP is a fairly unusual
23 feature of the framework. However, there are similar provisions in the new PBR
24 law in North Carolina. Other approved MYRPs have off-ramp provisions.

25 Moreover, the proposed provision that allows PSE to file a rate case is unlikely to

1 trigger a rate case. Given the three-year plan period, the Company would likely
2 file a rate case at the beginning of Year 3 anyway in order to have new rates
3 effective upon the expiration of the plan.

4 I would also note that this provision only gives PSE the *right* to file a rate case,
5 the Company is not required to file a rate case. In my experience, small and
6 temporary underearnings rarely prompt a utility to file a rate case. The decision to
7 file a rate case is based on several factors including the magnitude of the earnings
8 deficiency, forecasted changes in costs or revenues, expectations of changes in the
9 authorized rate of return resulting from a potential rate case, the ability to seek
10 supplemental revenue through deferrals or cost trackers, and political
11 considerations. PSE might not file a case even if it is eligible to do so because the
12 situation is expected to be temporary, and it is in the Company's long-term
13 interest to make MYRPs work.

14 **Q. Please discuss the impact of PSE's MYRP on regulatory efficiency.**

15 A. MYRPs should improve the efficiency of regulation and the Company's plan can
16 accomplish this, first and foremost by reducing the frequency of rate cases.
17 Regulatory resources would thereby be freed up to focus more on utility capital
18 expenditures, rate designs and miscellaneous generic issues. This is a notable
19 advantage in a period of rapid change when the UTC must contend with a swirl of
20 issues. Of course, the magnitude of these benefits will depend on the other filings
21 and processes that are required as part of, or in conjunction with, the MYRP.

1 **Q. Please discuss the attention PSE’s MYRP gives to other goals.**

2 A. The goals of utility regulation extend beyond ensuring that the Company provides
3 service of reasonable quality at a reasonable price. In Washington, the impact of
4 utility operations on the environment and disadvantaged groups are of special
5 interest. The Company’s MYRP proposal encourages attention to these other
6 goals through revenue decoupling and its scorecard of metrics and PIMs. PSE is,
7 additionally, subject to legislative mandates to decarbonize its energy supply,
8 pursue cost-effective DSM, and spread benefits of the energy transition equitably.

9 **Q. Is the Commission hamstrung by SB 5295 in its ability to approve an MYRP**
10 **that it believes to be just and reasonable?**

11 A. No. Legislation in several states has detailed a particular approach to Altreg and
12 provided regulatory commissions limited discretion to accept a different
13 regulatory approach. The Washington MYRP law, in contrast, gives the
14 Commission significant latitude and affords it considerable discretion over the
15 design of any MYRPs that are adopted.

16 **VII. CONCLUSION**

17 **Q. Does this conclude your direct testimony?**

18 A. Yes, it does.