BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	)	DOCKETS UE-240004, UG-240005, and UE-230810 (*Consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY Petitioner, For an Accounting Order Authorizing deferred accounting treatment of purchased power agreement expenses pursuant to RCW 80.28.410	)	

RESPONSE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

August 06, 2024

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EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is Tietotie 2, Suite 208, Oulunsalo, Finland FI-90460.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am the Principal Consultant for MW Analytics, a consulting firm that provides professional services to large energy consumers, primarily in the Western United States. I am appearing in this matter on behalf of Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are energy consumers located throughout the Pacific Northwest, including electric service and gas service customers of Puget Sound Energy ("PSE").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Accounting degree from the University of Utah. I have sponsored testimony in several regulatory jurisdictions in the United States, including before the Washington Utilities and Transportation Commission (the "Commission"). A list of recent cases where I have submitted testimony can be found in **Mullins, Exh. BGM-2**.

Q. WHAT IS THE PURPOSE OF YOUR RESPONSE TESTIMONY?

A. My testimony responds to PSE's Direct Testimony. I discuss the rate base measurement periods PSE has proposed in the respective rate years in this docket. I also discuss certain Energy Imbalance Market ("EIM") revenues related to congestion neutrality charges and greenhouse gas credits. I also discuss PSE's Colstrip Regulatory Liability, as well as PSE's proposal to establish three new rate tracking mechanisms that would function outside of the Multi-Year Rate Plan. Related to one such tracker – the Clean Clean Generation Resources ("CGR") tracker, I address PSE's proposal to recover Construction Work In Progress ("CWIP"). Related to power costs, I address PSE's proposal to establish an on-going, annual Power Cost Adjustment update, and its proposal to utilize Power Cost Only Rate Case at its discretion. Finally, I address PSE's imprudence in acquiring unreasonably costly, short-term resources in order to meet its 2025 interim target under the Clean Energy Transformation Act ("CETA").

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS

A. My principal recommendations are as follows:

- *Colstrip Retirement Liability Balances:* I recommend that on December 31, 2025, Colstrip liability balances be consolidated into a single regulatory liability, which accrues interest compounded at PSE's Allowance for Funds Used During Construction ("AFUDC") rate.

- *Rate Base Measurement (Adjs. 6.26-6.32):* I recommend the Commission adhere to the traditional used and useful standard and only allow pro forma capital in rates that is demonstrated to be used and useful as of the rate effective dates of the respective rate years.

- *EIM Benefits* (*Elect. Adj. 6.38):* I recommend that congestion and marginal loss revenues associated with the EIM be modeled in power costs in a manner similar to greenhouse gas revenues.

- *Clean Generation Resources Rate Adjustment, Wildfire Prevention Tracker, Decarbonization Rate Adjustment:* I recommend that the Commission reject each of these newly proposed trackers as a matter of policy. In the event that the Commission declines to reject these trackers outright, I separately address proposed changes to the Clean Generation Resources Rate Adjustment. Dr. Lance Kaufman's testimony makes substantive recommendations related to the Wildfire Prevention Tracker and the Decarbonization Rate Adjustment.

- *Construction Work In Progress ("CWIP") Recovery in Clean Generation Resources Rate Adjustment:* I recommend the Commission reject the request for recovery of CWIP in rate base.

- *Power Cost Updates and Power Cost Only Rate Cases:* I recommend that the Commission reject PSE's proposal to institute ongoing, annual power cost updates that would go beyond the span of the current Multi-Year Rate Plan, and that the

Commission reject PSE's proposal to use a Power Cost Only Rate Case ("PCORC") at its discretion.

- *Return on Power Purchase Agreements:* I recommend the Commission reject PSE's proposal to earn a return on CETA demand response power purchase agreements.

II. COLSTRIP REGULATORY LIABILITY

Q. WHAT IS YOUR RECOMMENDATION FOR THE COLSTRIP REGULATORY LIABILITY?

A. Beginning on January 1, 2026, I recommend that the balances associated with Colstrip be transferred into a single regulatory liability account. I recommend that the liability account be established as a fund that accrues interest at the same interest rates as AFUDC.

Q. WHAT AMOUNT OF REGULATORY LIABILITY HAS PSE ACCRUED FOR COLSTRIP?

A. In its workpapers, PSE identified a total liability balance of $100,713,506 associated with Colstrip.[1] This balance, which was measured over the 12-months ending June 30, 2023, is aggregated over many different accounts, including accounts related to monetized PTCs, treasury grants, unrecovered plant balances, and expended decommissioning expenditures. The net balance of all of these accounts is a liability balance because of the funds paid by customers and earmarked for decommissioning and remediation expenditures.

1 Mullins, Exh. BGM-4 (PSE's response to AWEC Data Request ("DR") 45).

Q. HOW IS THE COLSTRIP REGULATORY LIABILITY BALANCE HANDLED FOR RATEMAKING?

A. The rate base, as well as operating expenses, associated with Colstrip are recovered through the Colstrip Tracker, Schedule 141-COL. The Colstrip tracker was most recently approved in Docket UE-230808, with an approximate $52,580,820 revenue requirement.[2]

Q. HOW WILL THAT REVENUE REQUIREMENT CHANGE WHEN COLSTRIP IS REMOVED FROM RATES.

A. The ongoing operating expenses and depreciation expenses embedded in Schedule 141-COL revenue requirement will cease when Colstrip is removed from rates on December 31, 2025. Further, due to ongoing accumulated depreciation of Units 3 and 4, the net regulatory liability balance is expected to grow by approximately $80,000,000 to around $180,000,000, relative to June 30, 2023, levels. Given the elimination of operating and depreciation expenses, as well as ongoing accumulated depreciation, the revenue requirement attributable to Schedule 141-COL will be a materially negative sur-credit value of approximately $18,000,000 due to ratepayers each year. These numbers are obviously rough estimates.

Q. HAS PSE CONSIDERED THE REDUCTION IN SCHEDULE 141-COL REVENUES IN ITS REVENUE REQUIREMENT IN THIS PROCEEDING?

A. No. While PSE reported the changes in revenue requirement associated with many other schedules, it did not estimate the impact of the change in Schedule 141-COL revenues,

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[2] *See* Docket No. UE-230808, workpaper 230808-Advice-2023-43-PSE-WP-Rev-Req-(09-29-23).xlsx, Tab "Revenue Requirement," Cell "C57."

which would offset as much as $70,000,000 of the RY 2 impacts, depending on the treatment approved for the schedule.[3]

Q. DID PSE PROVIDE A PROPOSAL FOR HOW TO HANDLE THE REGULATORY LIABILITY BALANCES?

A. No. When asked in discovery what PSE's proposal was for the regulatory liability balances, PSE stated that the "the treatment of Colstrip costs […] are outside the scope of this proceeding."[4] I disagree. If the status quo treatment, using the Colstrip tracker, is applied PSE will be required to refund significant amounts of funds to ratepayers for the regulatory liability balances on its books. This would be an undesirable outcome, since those funds were meant to be applied towards the Colstrip retirement.

Q. WILL THE FUNDS ACCRUED BE SUFFICIENT TO COVER THE DECOMMISSIONING AND REMEDIATION LIABILITY?

A. Based on the most recent estimates, they will be. In Docket UE-230808, PSE forecast unrecovered decommissioning and remediation expenses of $165,876,129, excluding incremental accretion of the accelerated decommissioning and remediation expenses currently being recovered.[5] The approximate $180,000,000 expected Colstrip regulatory liability will, therefore, be more than sufficient to cover the remaining decommissioning and remediation liability, even without considering additional interest accrued on the balance subsequent to the removal of Colstrip from rates.

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3 *See* e.g. Free, Exh. SEF-3 at 1.

4 Mullins, Exh. BGM-4 (PSE's Resp. to AWEC DR 45).

5 *See* Docket No. UE-230808, workpaper 230808-Advice-2023-43-PSE-WP-Rev-Req-(09-29-23).xlsx, Tab "Estimated D&R Recovery," Cell "C19."

Q. IS THERE UNCERTAINTY REGARDING THE DECOMMISSIONING AND LIABILITY COSTS?

A. Yes. The situation surrounding Colstrip is dynamic and changing rapidly. The day before submitting this testimony, it appears that PSE entered into an agreement to transfer its ownership in Colstrip Units 3 and 4 to Northwestern Energy, though the terms of that agreement are not yet known. The ultimate decommissioning and remediation liability could be higher or lower than the amount PSE has estimated. Certainly, it would be unfair if ratepayers were to incur incremental decommissioning and remediation expenditures due to Northwestern deciding to continue to operate the plant well beyond Washington's exit date. Therefore, it is possible that the regulatory liability funds will be insufficient to cover the ultimate decommissioning and remediation liability, or that they could be even more sufficient than expected, if Northwestern picks up more of the tab.

Q. HOW DO YOU RECOMMEND HANDLING THE BALANCES IN THIS CASE?

A. Notwithstanding this uncertainty, I have three general recommendations:

First, I recommend that recovery through Schedule 141-COL cease as of December 31, 2025. At that point, the plant balances will be fully repaid, and it would be contrary to the purpose of the schedule to refund the ongoing rate base benefits of the accrued decommissioning and remediation liabilities through the supplemental schedule. Notwithstanding, it is still necessary to credit customers with the financing benefits of the monies they have accrued.

Second, I recommend that as of December 31, 2025, all the remaining balances be transferred into a single decommissioning and remediation regulatory liability account.

This will make it simpler to track the funds that have been accrued and to assess interest on the account for the benefit of ratepayers.

Third, I recommend that the liability account balance accrue interest to account for the financing benefit of the funds. Rather than continuing to include the liability rate base balances in a tracker, removing those amounts from rate base altogether and accruing interest on the account itself, will set aside more funds for the decommissioning and remediation activities, or for other purposes, depending on the outcome of the agreement with Northwestern Energy.

Q. WHAT INTEREST RATE DO YOU RECOMMEND BE APPLIED TO THE BALANCE?

A. The interest rate I propose is the cost of capital applied for purposes allowance for funds used during construction ("AFUDC"), which is the financing rate accrued on construction work in progress ("CWIP"). Considering PSE's concerns about the financing costs of CWIP, providing the regulatory liability balance the same interest rate as CWIP will alleviate some of the cashflow constraints that PSE identifies in its testimony with respect to investing in clean generation resources. It is also important that the interest compound, given that it may be many years before it is spent on decommissioning activities.

Q. SHOULD THE BALANCES BE REEVALUATED IN FUTURE CASES?

A. Yes. While I am not recommending that any of the accrued decommissioning and remediation liability funds be refunded to ratepayers in this proceeding, if the balance grows to an amount significantly greater than the expected decommissioning and remediation liability at issue, it may be desirable to do so in the future, or alternatively repurpose the funds to cover other future investment costs. Accordingly, I recommend that the Commission require PSE to report on the decommissioning and remediation liabilities in all future rate cases, and for PSE to propose a mechanism to refund balances exceeding the expected decommissioning and remediation liability, if necessary.

III. RATE BASE MEASUREMENT

Q. DO YOU SUPPORT PSE'S APPROACH TO REVENUE REQUIREMENT IN THIS DOCKET?

A. No. Historically, Washington has been a state that adhered strictly to the concept of a historic test period when calculating revenue requirements. The concept of a historic test period was an important ratepayer protection, as it relied on the principal that only actual costs or costs that could be demonstrated based on a known and measurable change, were eligible to be considered in a revenue requirement calculation. As a result of statutory changes, the traditional, modified historical test period is no longer being required of Washington utilities. In recent years, utilities have largely ignored critical ratepayer protections with the push towards highly complicated multi-year rate plan filings. Through these filings, the envelope of revenue requirement has been continually pushed in the favor of utilities and at the expense of ratepayers. It has come to the point where ratepayers have little recourse in a proceeding, such as here, with respect to forecasting assumptions, except perhaps having the ability to litigate an eventual refund in an after-the-fact capital review process, which has its own set of problems.

Put simply, the regulatory policy towards revenue requirement in Washington has been flipped on its head. The utilities now include forecast capital additions well beyond the rate effective date and aggressive assumptions regarding cost escalation of operating expense throughout the rate effective periods. By doing so, the utilities effectively have done away with traditional ratemaking principles, such as the used and useful and known and measurable standards. However, these standards continue to be important both in terms of fairness and equity between ratepayers and shareholders. They also encourage a utility to control costs and manage operations in a prudent and reasonable manner. The traditional concept of an historic test year was intended to protect customers, and the erosion of the historic test year and other traditional ratemaking principles has had negative impacts on ratepayers, evidenced by the repeated, major rate increases being proposed by nearly every utility in the state in recent years. The current proceeding is no exception.

Q. HAVE MULTI-YEAR RATE PLANS REDUCED ADMINISTRATIVE BURDENS?

A. No. By all accounts, moving to multi-year rate plans has only made the regulatory process in Washington more burdensome. Not only are the filings exponentially more complicated, but they have been no less frequent than before. The slew of contemporaneous dockets and processes necessary to manage the rate plan process after the fact have also made the process even more unworkable. Contrary to its purpose, the new policy towards multi-year rate plans has encouraged utilities to submit filings with forecasting assumptions that are increasingly aggressive, while at the same time ratepayers continue to struggle with inflationary cost pressures on nearly every aspect of their consumption.

Q. DOES THE COMMISSION HAVE TO APPROVE A MULTI-YEAR RATE PLAN?

A. No. I am not an attorney, although my understanding of RCW 80.28.425(1) is that a utility is required to include a multi-year rate plan option in its general rate case filing, but that the Commission has discretion to "approve, approve with conditions, or reject, a multi-year rate plan" filed by a utility. It also has the authority to approve or approve with conditions "an alternative proposal made by one or more parties."[6] Thus, a forecast test period is not mandatory in the context of the requirement for a utility to submit a multi-year rate plan. To the contrary, the Commission has broad flexibility in the assumptions that it uses to establish revenue requirement, whether approved in the context of a multi-year rate plan or not.

Q. CAN THE PROBLEMS WITH MULTI-YEAR RATE PLANS BE RESOLVED IN AFTER-THE-FACT CAPITAL REVIEWS?

A. No. If a utility has an approved budget in a rate case, it will have an incentive to spend up to that budget to avoid needing to issue a refund to customers in an after-the-fact capital review. As discussed below, setting rates based on budgetary forecasts provides little assurance that those rates are just and reasonable because there is no objective way of determining the reasonableness of a budget. Thus, the utility has an incentive to inflate its budget in a rate case which, if approved, gives it a corresponding incentive to invest more capital than it otherwise would under an historical test year approach. In an after-the-fact capital review process, the reasonableness of the amount of capital deployed becomes largely irrelevant so long as the amount is within the approved budget.

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6 RCW 80.28.425(1).

Consequently, at no point in the ratemaking process do parties or the Commission have an opportunity to objectively determine the reasonableness of a utility's capital spending.

Q. DO THE USED AND USEFUL AND KNOWN AND MEASURABLE STANDARDS PREVENT A UTILITY FROM EARNING ITS RETURN?

A. No. These standards do not prevent a utility from having the opportunity to earn its authorized rate of return. This is especially true given the "modified" historical test period the Commission had generally adopted prior to the use of multi-year rate plans. The modified historical test period provides utilities with a revenue requirement based on end-of-period rate base, including allowances for pro forma adjustments. Setting rates in this manner, based on known costs and actual plant, balances the interests of the utility in having a reasonable opportunity to earn its authorized return while creating an incentive to control costs and spending within historical levels. A utility, such as PSE, needs to manage its business to avoid an unsustainable cost trajectory, which PSE is capable of doing.

Q. HOW CAN THE COMMISSION EVALUATE THE REASONABLENESS OF A BUDGET, AS OPPOSED TO KNOWN AND MEASURABLE COSTS?

A. By contrast, setting utility rates based on budgets is problematic because there is no objective way to assess the reasonableness of a budget, other than questioning expertise or the intentions of those that developed it. Use of a budget puts the Commission and ratepayers in an impossible situation of having to accept what a utility says is reasonable, without a clear reconciliation to the actual costs incurred. Given PSE's current revenue increase request and the circumstances facing ratepayers, it is reasonable to hold PSE to traditional ratemaking standards. Now that we have more experience with multi-year rate plans, reconsideration of the current practice of forecasting capital in rates is warranted. While the boundaries have been pushed in the past, the pendulum has swung too far, and it is important to reinstate these important ratemaking concepts more firmly.

Q. WHAT IS YOUR RECOMMENDATION ON PSE'S CAPITAL FORECAST?

A. My recommendation regarding PSE's capital forecast is simple. I recommend that only capital demonstrated to be used and useful on or before the rate effective date of the respective rate years be considered in revenue requirement. This is consistent with the used and useful standard. It is also the baseline method described in the multi-year rate plan statute, which states "[f]or the initial rate year, the commission shall, at a minimum, ascertain and determine the fair value for rate-making purposes of the property of any gas or electrical company that is used and useful for service in this state as of the rate effective date."[7]

Q. IS IT MANDATORY FOR THE COMMISSION TO INCLUDE CAPITAL ADDITIONS AFTER THE RATE EFFECTIVE DATE?

A. No. My understanding is that under RCW § 80.04.250, the Commission has flexibility to consider rate period capital additions, but that doing so is not mandatory. The operative clause on this matter is permissive, stating that the "valuation *may* include consideration of any property of the public service company acquired or constructed by or during the rate effective period."[8] The only obligatory clause regarding test period capital is in RCW § 80.04.250(3), which requires the Commission to adopt a standard process for reviewing test period capital additions—a requirement the Commission complied with

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7 RCW § 80.28.425(3)(b).
8 RCW § 80.04.250(2).

through its Used and Useful Policy Statement—although that process only applies if the Commission in fact decides to include rate period capital additions in revenue requirement in the first place.

Q. DOES THE COMMISSION'S USED AND USEFUL POLICY STATEMENT REQUIRE RATE PERIOD CAPITAL TO BE INCLUDED IN RATES?

A. No. The Used and Useful Policy Statement provides guidance for how the Commission would review test period capital additions, but again, it is not a pronouncement that the Commission would consider rate period capital additions in all cases. The Commission expressly affirmed the continued use of the modified historical test period approach stating:

> This Policy Statement affirms – and requires that regulated companies include and consider in their proposals – the Commission's longstanding practices regarding property placed in service. These practices require companies to show that the property will be used and useful; that proposed pro forma adjustments to test year amounts will involve known and measurable events and adhere to the matching principle (i.e., the principle that costs should be matched to offsetting factors), including accounting for all offsetting factors; and that costs were prudently incurred.[9]

Q. HOW DO YOU RECOMMEND THE CAPITAL FORECAST BE EVALUATED FOR RATE YEAR ("RY") 1?

A. My recommendation is that only capital demonstrated to be in service as of December 21, 2024, be included in RY 1 revenue requirement. Considering that PSE used a Historical Period corresponding to the 12-months ending June 2023, developing revenue requirement based on capital in service as of the rate effective data still requires a forecast of capital additions over the approximate 18-month period of July 1, 2023, and

[9] Docket No. U-190531, Policy Statement on Property That Becomes Used and Useful After Rate Effective Date at ¶ 20 (Jan. 31, 2020) (internal citations omitted).

December 21, 2024. To account for this, I recommend that PSE be required to file an attestation concurrent with its compliance filing that the capital included in its forecast for 2024 was placed into service. If the amount for any project exceeding $1,000,000 placed into service is less than PSE had forecast, PSE would be required to reduce the rates that go into effect by the revenue requirement impact of the difference. This would be a project-by-project attestation, with no offsets for overspending on a forecasted project.

Q. DO YOU SUPPORT THE USE OF A PORTFOLIO APPROACH IN A CAPITAL REVIEW?

A. No. Regardless of whether the Commission approves my recommendation to limit capital additions to those in service as of the rate effective date or adopts a post-rate period review process, I recommend that all future capital reviews be conducted on a project-by-project basis. PSE's recent Provision Capital Compliance Filing in Docket Nos. UE-220066 and UG-220067 demonstrates why it is critical that capital review processes be conducted on a project-by-project basis. That filing was the first full capital review submitted under the new, multi-year rate plan construct, and it is apparent that it is virtually impossible to compare back to the specific projects that PSE included in the 2022 general rate case. If PSE is going to spend on a different set of projects than identified in this rate case, then the Commission has no basis to establish that the capital forecast is reasonable to begin with. In its Used and Useful Policy Statement, the Commission stated that "[t]he review will not, however, simply be a matter of matching identified rate base to the rate base provided in rate-year Commission Basis Reports."[10] Yet, this is precisely the approach PSE has used and is proposing in this case, requesting the Commission approve a placeholder for capital additions, as opposed to investments in specific and discrete projects.

Q. HOW DO YOU PROPOSE HANDLING THE CAPITAL ADDITIONS FOR RY 2?

A. The same recommendation that I recommended for RY 1 could be applied to RY 2. PSE's actual capital spending in calendar year 2025 would be compared to the forecast presented in this case on a project-by-project basis. At the time RY 2 rates go into effect, PSE would submit a compliance filing attesting to the specific project cost that were incurred in 2025 and to the extent that any project exceeding $1,000,000 were lower than forecast, rates would be reduced by the revenue requirement of the difference. Again, this would be done a project-by-project basis, with no offsets for overspending on a forecasted project.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION.

A. Under my recommended approach there would be no after the fact capital review, streamlining the administrative burden with respect to the PSE's rate plan filing. Given the complicated capital modeling that PSE performed, I was unable to calculate the impact of this recommendation. Therefore, I recommend that the Commission require PSE to perform the updated rate base calculations as a part of its compliance filing, subject to party review.

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[10] *Id.* at ¶ 42.

IV. CONGESTION NEUTRALITY CHARGES

Q. HOW DOES PSE FORECAST EIM BENEFITS IN NET POWER SUPPLY EXPENSE ("NPSE")?

A. The method for forecasting EIM benefits in NPSE was described generally by PSE witness Mueller.[11] PSE performed an Aurora dispatch modeling on a sub-hourly basis and determined the volume and pricing of incremental purchases and sales generated in the sub hourly modeling to determine the amount of EIM benefits included in its power cost forecast.

Q. WHAT IS THE PROBLEM WITH PSE'S FORECAST?

A. The benefits PSE calculated were, with the exception of greenhouse gas revenue settlements, driven entirely by sub-hourly dispatch. The sub-hourly dispatch captures the net revenues from instructed imbalances, which are described further below. It does not, however, capture the benefits of other market settlements, such as neutrality charges. These other settlements represent material benefits to the EIM footprint and are separate from the sub-hourly dispatch benefits PSE calculated.

Q. WHAT IS AN IMBALANCE?

A. An imbalance represents the difference between the volume of load or generation scheduled (*i.e.*, planned or forecast) and the actual volume. The concept of an imbalance is described graphically in **Figure 1**, below:

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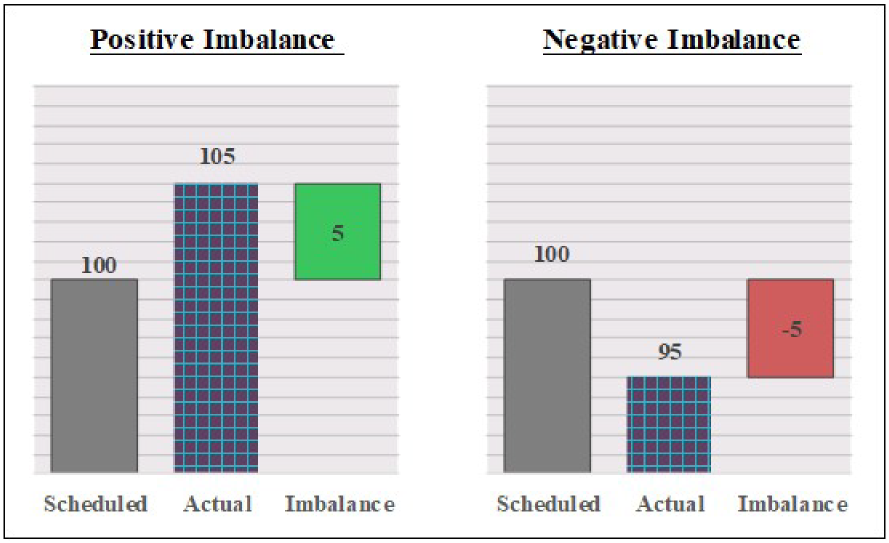
11 Mueller, Exh. BDM-1T at 33:18-35:2.

Figure 1
Illustration of Positive and Negative Imbalances from Energy Source (MWh)



Prior to an operating period, typically an hour, a wholesale transmission customer must submit a forecast to its transmission service provider detailing expected sources and uses of electricity in the operating period, including expected generation from network resources and expected loads based on its load forecast. These forecasts are generally referred to as a "schedule." To the extent that the actual sources or uses of electricity vary from the scheduled amount, the transmission customer will have an energy imbalance. A balancing area authority is responsible for maintaining the voltage and frequency of its transmission system. To meet these obligations, a balancing area authority must dispatch resources in real-time to serve imbalances in its area, including the imbalances of transmission customers. Correspondingly, transmission customers must reimburse the transmission service provider for the imbalance energy provided by, or be reimbursed for imbalance energy supplied back to, the balancing area. In other words, an energy imbalance can be both positive or negative, resulting in cases where sometimes the transmission provider must pay for shortfall imbalance energy and other times when it is paid for excess imbalance energy. The charges for these energy imbalance services are detailed in the transmission service provider's open access transmission tariff. Historically, energy imbalance services were settled using a percentage of monthly market index prices, but that changed with the initiation of the EIM.

Q. HOW DOES THE EIM CREATE A MARKET FOR IMBALANCE SERVICES?

A. The EIM provides an organized market for imbalance services that is settled in 15-minute and, subsequently, 5-minute intervals over the course of an hour. Before the EIM, each transmission system operator in the West managed imbalances independently. The EIM started trading nearly ten years ago in November 2014 between PacifiCorp and the California Independent System Operator ("CAISO") as a then novel framework to jointly dispatch in real-real time to serve imbalances in the most economical way possible across the two systems. It has since expanded rapidly through the fragmented balancing authority areas in the Western Interconnection, with most now participating in the market framework. In the EIM, real-time dispatch is managed and optimized collectively over the entire EIM footprint, as opposed to each balancing area going it alone. The market uses a computer model operated by the CAISO that optimizes dispatch in real-time and then settles imbalance energy based sub-hourly locational marginal prices ("LMP") calculated in the same model. As a part of the market, dispatchable generators are re-dispatched relative to their scheduled output and used to serve imbalance energy of non-dispatchable resources and loads across the entire EIM footprint, with the objective of doing so in the most economical way possible. Dispatchable generators are then compensated for responding to the market instructions.

Q. WHAT ARE INSTRUCTED AND UNINSTRUCTED IMBALANCES?

A. In the hour-ahead, all market participants must submit schedules that balance their individualized system, meaning that all scheduled generation and scheduled load must be equal. The CAISO market model, however, reoptimizes the sub-hourly dispatch for the entire EIM footprint, subject to the actual operating costs and capabilities of dispatchable resources, as well as transfer limitations and other security constraints between participants. Over the course of an hour, the market model will provide automated generation instructions for dispatchable resources to dispatch up or dispatch down, relative to the scheduled output to serve the footprint more efficiently. These instructions are referred to as an "Instructed Imbalance." In contrast, an "Uninstructed Imbalance" occurs when the actual energy from a non-dispatchable resource or a load is different from the forecasted schedule.

Q. HOW DO UTILITIES BENEFIT FROM RESPONDING TO MARKET INSTRUCTIONS?

A. The EIM settlement revenues from an instructed imbalance represent the gross proceeds from the EIM, and do not include the cost of fuel incurred to generate those proceeds. The net benefit of an instructed imbalance, therefore, is the margin between the gross settlement proceeds and the incremental fuel costs from responding to the EIM dispatch instructions. Importantly, dispatch instructions may be up or down. A high-cost dispatchable resource could also be instructed to back down production, in which case, the utility saves on fuel costs, but is also required to reimburse the cost of EIM energy that it consumed instead of generating. In this instance the net benefit is the difference between the fuel cost savings and the settlement payment made to the EIM**.**

Q. HOW DOES PSE FORECAST THE BENEFIT OF INSTRUCTED IMBALANCES?

A. In its sub-hourly dispatch calculation, PSE performs a counterfactual dispatch analysis where it estimates the benefits of dispatching in 15-minute increments. The sub-hourly dispatch calculation PSE performs is designed to capture the benefit of instructed imbalances by calculating the incremental sales and purchases from its generation for responding to dispatch instructions in 15-minute intervals.

Q. DOES PSE'S FORECAST CONSIDER EIM SETTLEMENT REVENUES OTHER THAN INSTRUCTED IMBALANCES?

A. No. In response to AWEC Data Request 11, PSE provided the settlement data associated from the EIM since 2020. I have attached a summary of PSE's response to that data request in **Mullins, Exh. BGM-3C**. The majority of the interchange in the market is captured through instructed and uninstructed imbalances. As noted below, however, the benefits of several charges have been omitted from PSE's calculation.

Q. WHAT CHARGES HAVE BEEN EXCLUDED?

A. PSE's calculations exclude the financial benefit of other valuable settlement transactions called "neutrality charges" or sometimes referred to as "offsets." These specific neutrality charge settlements that were excluded from PSE's EIM benefit calculation are congestion offsets and marginal losses offsets. While there are several other charges that have been excluded, such as over/under scheduling charges, those are not material enough to warrant consideration in the EIM benefits calculation at this time.

Q. HAVE YOU ATTACHED DOCUMENTATION FROM THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR DESCRIBING NEUTRALITY CHARGES?

A. Yes. The above charges are detailed in the Business Practice Manual for Settlements & Billing of the CAISO. **Mullins, Exh. BGM-5** contains the relevant configuration guides describing each of these settlements. Generally, these neutrality charges arise because the sum of the energy imbalance settlements paid and those received do not sum to zero, most commonly resulting in excess revenues for the market. These three settlement charges correspond to the three components of the locational marginal price – congestion, losses, and energy – and are designed to reallocate the excess revenues, or costs, earned in by the market using a cost-causative allocation method.

Q. WHY DO THE INSTRUCTED AND UNINSTRUCTED ENERGY IMBALANCE SETTLEMENTS NOT SUM TO ZERO?

A. As stated, LMPs have three different components: congestion, losses, and energy. Accordingly, LMPs are different at each point or node in the system. If they were not, one can devise a simplistic example, where the EIM is settled on a single price for all instructed and uninstructed imbalances. In such a case, the charges assessed for purchasing imbalance energy and the revenues paid for supplying it would be the same. It would result in zero net revenues for the overall market. That simplistic example, however, is not how the market operates. The market is specifically designed to assess higher prices where demand for energy imbalance services is higher, and lower where it is not. This is a fundamental part of the economic optimization of the EIM footprint. Because of the effects of congestion and losses, there are unique prices throughout the system and the charges assessed for purchasing imbalance energy will tend to be at higher prices than for supplying it, resulting in net revenues to the overall market footprint. This intuitively makes sense, because the points where energy imbalances are being purchased generally have higher demand, and correspondingly, higher prices. The CAISO, however, does not keep the net revenues resulting from the differential pricing for itself. It allocates the revenues to participants using the neutrality settlement charges identified above, one for each component of the LMP.

Q. IS AN ADJUSTMENT TO PSE'S EIM FORECAST FOR NEUTRALITY CHARGES NECESSARY?

A. Yes. The neutrality charges are not considered in the sub-hourly dispatch modeling PSE performed. Therefore, it is necessary to include them separately, as an addition to the EIM benefits calculation. Apart from the instructed imbalances, the neutrality charges represent a separate benefit to the overall footprint and are not otherwise captured in benefit of responding to market instructions. Absent considering PSE's share, the forecast EIM benefits included in NPSE will be understated.

Q. DOES PSE MAKE A SEPARATE ADJUSTMENT FOR GREENHOUSE GAS REVENUE SETTLEMENTS?

A. In connection to California's cap and trade program, PSE is provided additional settlement revenue for dispatching carbon free resources in the EIM. The energy from this dispatch can be used by California utilities to comply with the state's cap and trade program, and accordingly, market participants that provide carbon free energy are compensated through greenhouse gas settlements. This is accomplished through an adder in the dispatch price assessed to eligible resources, which is not reflected in the EIM LPMs used for purposes of instructed imbalances and used in PSE's sub-hourly dispatch modeling. Accordingly, the EIM provides additional revenues through separate greenhouse gas settlement charges when an eligible carbon free resource is dispatches in the market. Since the benefit of this charge is not considered directly in PSE's sub-hourly modeling, it includes a discrete adjustment for greenhouse gas revenues in its EIM forecasting methods. This same approach, however, also needs to be followed with respect to other settlements, such as congestion and marginal losses uplift charges.

Q. WHAT AMOUNT OF REVENUES HAS PSE HISTORICALLY RECOGNIZED FROM THESE SETTLEMENTS?

A. The amount of revenues that it has recognized are summarized in **Exhibit, Mullins BGM-3C.** Since the amounts are confidential, I am not citing them here. I recommend that the four-year average annual amount detailed in that exhibit be deducted from the net power cost forecast used in this case.

V. TRACKER SCHEDULES

Q. WHAT BASIS DOES PSE PROVIDE FOR NEEDING THE THREE NEW COST RECOVERY MECHANISMS IT PROPOSES IN THIS DOCKET?

A. Witness Steuerwalt argues that given PSE's anticipated capital investments over the MYRP "at a pace and scale far greater than what PSE has been required to support in prior cases,"[12] separate rate recovery mechanisms are necessary for the Company's financial health. In particular, PSE is proposing a Clean Generation Resources Rate Adjustment (Schedule 141CGR), a Decarbonization Rate Adjustment (Schedule 141DCARB), and a Wildfire Prevention Tracker (Schedule 141WFP). These rate recovery mechanisms are in addition to the Company's proposal to forecast capital and

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12 Stueurwalt, Exh. MS-1Tr2 at 34:3-4.

engage in a capital review process, as is described above in my testimony, as well as its proposal to virtually eliminate its power cost risk by allowing annual Power Cost Adjustments and the option of a Power Cost Only Rate Case ("PCORC"), addressed in my testimony below.

Q. WHAT ARE YOUR CONCERNS WITH PSE'S PROPOSAL TO INSTITUTE THREE NEW TRACKER MECHANISMS IN THIS CASE?

A. Generally speaking, PSE's proposed tracker mechanisms constitute undesirable, single-issue ratemaking and work to inappropriately shift risk away from PSE's shareholders and onto customers, thereby reducing the Company's incentive to manage costs during the pendency of its MYRP, and also calls into question the value of spending ten months litigating a MYRP if the major cost drivers are ultimately recovered in separate trackers, which are subject to a separate process and again require extensive resources from parties who are likely then balancing the work demands of MYRPs from other utilities. Much like the flawed capital review process described above, these trackers only serve to benefit PSE's shareholders by allowing for the elimination of regulatory lag and removing the risk that the Company will not recover its full costs once rates for each MYRP are set.

Q. WHAT IS YOUR OVERALL RECOMMENDATION FOR THE THREE NEW TRACKER MECHANISMS IN THIS CASE?

A. I recommend that the Commission reject each of PSE's proposed tracker mechanisms in this case and require PSE to recover the costs as a component of base rates. The following section of my testimony discusses further issues with PSE's Clean Generation Resources Adjustment. The testimony of Dr. Lance Kaufman, also on behalf of AWEC, addresses necessary changes to both the Decarbonization Rate Adjustment and the Wildfire Prevention Tracker.

VI. CWIP RECOVERY

Q. WHAT HAS PSE PROPOSED WITH RESPECT TO CWIP RECOVERY?

A. Witness Free describes generally PSE's proposal with respect to CWIP recovery for resources recovered in its proposed Schedule 141 CGR. Effectively, PSE is seeking to recover CWIP in rate base in lieu of allowance for funds used during construction, during the period prior to when a plant is placed into service. PSE states that this is necessary to enable it to maintain sufficient cashflow to invest in clean energy investments.[13]

Q. HOW DOES PSE CURRENTLY RECOVER THE FINANCING COSTS OF CWIP?

A. The financing costs associated with CWIP are recovered through Accumulated Funds Used During Construction ("AFUDC"). Under the AFUDC approach, the financing costs are capitalized to the project and spread over the life of the asset, aligning costs with the period over which benefits are provided.

Q. DOES RECOVERING CWIP IN RATE BASE RESULT IN INTERGENERATIONAL INEQUITY?

A. Yes. Recovering CWIP in rate base would result in charging customers for the cost of a generation resource or utility investment prior to the date that the investment is placed into service and providing service benefits. Those customers paying for the cost prior to the in-service date may not be the same set of customers that ultimately benefit from the underlying capital addition. On the flipside, future customers that do benefit from the

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13 Free, Exh. SEF-1T at 9:10-12, 14-15..

resources will not be required to commit any funding for financing costs incurred during the project construction, requiring them to bear a lesser burden for the overall project costs. Long-standing Commission precedent supports efforts to mitigate intergenerational inequity.[14]

Q. DOES RECOVERING CWIP THROUGH RATE BASE ALSO REDUCE UTILITIES INCENTIVES TO EFFICIENTLY MANAGE CONSTRUCTION?

A. Yes. If a utility is provided recovery of its return prior to when the project is placed in service, it may be incentivized to act less efficiently with respect to bringing the project into service. By including CWIP in the rate base, the risks associated with construction delays, cost overruns, or project cancellations are also transferred from the utility and its investors to ratepayers.

Q. CAN THE COMMISSION DETERMINE THAT THE COST OF CWIP ARE PRUDENT PRIOR TO A RESOURCE BEING PLACED INTO SERVICE?

A. No. There is always uncertainty in the completion and approval of utility projects. If a project is delayed, altered, or canceled, customers might end up paying for investments that do not yield any service or benefit.

Q. SHOULD THE COMMISSION BE SWAYED BY PSE'S ASSERTION THAT ITS PROPOSAL IN THIS CASE WILL ULTIMATELY COST CUSTOMERS LESS OVER THE LIFE OF THE ASSET?

A. No. PSE provides a table with a comparison of recovery methods for generation resources,[15] wherein the Company asserts that under the conventional recovery method for generation resources – which would not allow for recovery of CWIP – ratepayers will

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14 *See* Docket No. UE-190529 et al., Order 08/05/03 at 190:662 (July 8, 2020); Docket No. UE-152253, Order 12 at 19:53 (Sep. 1, 2016).

15 Free, Exh. SEF-1T at 11:12.

pay slightly less than $4 million more than under the Company's proposed hybrid method where CWIP will be recovered in rates starting at the rate case following construction, at which point AFUDC recovery would cease. However, this comparison is misleading. The difference between the approaches is not whether PSE is provided compensation for financing charges, but the timing that the compensation occurs. The minor difference in the approaches is attributable to variations of the interest rates used, not necessarily a systematic benefit to ratepayers. And as noted above, PSE's proposal also causes intergenerational inequity and as acknowledged by PSE, imposes near-term rate pressure on customers who are already facing significant rate increases to comply with Washington state policies such as CETA and the Climate Commitment Act.[16]

Q. DO YOU AGREE WITH PSE'S PROPOSAL TO RECOVER CWIP IN RATE BASE?

A. No. Recovering CWIP through rate base can lead to inequities, inefficiencies, and misaligned incentives. AWEC recommends that the Commission reject this proposal.

VII. POWER COST UPDATES AND POWER COST ONLY RATE CASES

Q. PLEASE SUMMARIZE PSE'S PROPOSAL FOR POWER COST UPDATES.

A. In this proceeding, PSE asks the Commission to approve annual Power Cost Adjustments that would go beyond the current MYRP in perpetuity. This would allow PSE to update its forecast net power costs each year consistent with the updates included in the Company's 2022 General Rate Case settlement, and its actuals would continue to be reviewed in its Power Cost Adjustment Mechanism ("PCAM").

16 Free, Exh. SEF-1T at 10:1-12.

Q. WHAT ARE AWEC'S CONCERNS WITH PSE'S PROPOSAL FOR ANNUAL POWER COST UPDATES?

A. AWEC is concerned that on-going annual updates for PSE's net power costs, which would be permitted outside of the MYRP term, serves yet again to shift risk away from PSE's shareholders and onto PSE's customers by removing an incentive for PSE to manage power costs between rate cases. This also erodes the administrative efficiency of the MYRP and would cause additional work and filings that may not be beneficial or necessary to customers.

Q. WHAT ARE AWEC'S CONCERNS WITH PSE'S PROPOSAL TO RETAIN THE OPTION FOR A PCORC?

A. AWEC is concerned at PSE's continued attempts to erode the potential value of the MYRP by proposing yet another option for the Company to unilaterally decide when to seek additional rate recovery from customers outside of the MYRP process. PSE's MYRP includes an estimate of power costs for the duration of the MYRP. Allowing another bite at the apple by seeking an additional mechanism to recover costs yet again removes the Company's incentive to manage costs for the duration of the MYRP. When the PCORC was initially established, the Company did not have a MYRP – the regulatory framework at that time was therefore much different. Under PSE's proposal, the Company could file, and the Commission could issue a final order on a MYRP, setting rates based on a forecast of expenses and revenues for each rate year, only to have PSE then file a PCORC to bring in additional resources. The Company's request in this case is an undesirable attempt to remove *any* regulatory lag associated with its investments – a shift that again only serves to benefit PSE's shareholders.

Q. WHAT IS AWEC'S RECOMMENDATION IN THIS CASE FOR ANNUAL PCA UPDATES AND AN OPTION FOR A PCORC?

A. AWEC recommends that the Commission reject PSE's request for annual PCA updates that would span beyond the term of any MYRP approved by the Commission in this case. Whether to allow for power cost updates during a MYRP should remain a policy consideration for the Commission based on the specific facts and circumstances in that proceeding. Allowing PSE annual power cost updates is again a shift of cost discipline away from the Company at customers' risk.

VIII. RETURN ON POWER PURCHASE AGREEMENTS

Q. PLEASE DESCRIBE PSE'S REQUEST REGARDING THE AUTOGRID, ORACLE, AND ENEL X DEMAND RESPONSE PPAs.

A. PSE is seeking determination of prudency, recovery of the costs, and to earn a rate of return on the AutoGrid PPA,[17] Oracle PPA,[18] and Enel X PPA.[19] PSE is requesting to earn a return on these PPAs "pursuant to paragraph 32 of the Settlement Stipulation and Agreement on Revenue Requirement and All Other Issues Except Tacoma LNG and Green Direct, approved in PSE's last general rate case, Dockets UE-220066/UG-220067: 'The cost of any DER PPA for distributed generation, battery resources and demand response costs are eligible for recovery through PSE's PCORC, PCA Mechanism and/or annual power cost update and are eligible for potential earning on PPAs pursuant to RCW

17 Archuleta, Exh. GA-1T at 29:13-14.
18 *Id.* at 34:9-10.
19 *Id.* at 39:16-17.

80.28.410.'"[20] Inclusion of a rate or return on these demand response PPAs serves to add an additional $1.36 million in costs for PSE's customers over the course of the MYRP.[21]

Q. IS PSE'S REQUEST FOR RETURN ON ITS DR PPAs REASONABLE?

A. No. PSE's request for return on its DR PPAs is not reasonable. PSE has offered no reasonable justification for its proposal to reward shareholders for power purchase agreements, which are traditionally a pass-through expense in rates. PSE's proposal in this case is further unsupported by the fact that the Company already has a Performance Incentive Mechanism ("PIM") that provides PSE's shareholders with incentives to achieve demand response targets. Allowing a rate of return on demand response PPAs, while also allowing shareholders the opportunity to earn a PIM, would provide double incentives to PSE. Moreover, a return on demand response PPAs is neither mandated by statute[22] nor the revenue requirement settlement in PSE's 2022 general rate case, referenced above. In exercising its discretion on whether to allow for a rate of return, the Commission should be guided by ratemaking principles and Commission precedent emphasizing the balance of costs and benefits to customers – neither of which supports granting PSE's request to earn a rate of return on its CETA-compliant demand response contracts. Under PSE's proposal, customers would bear the burden of additional costs with no incremental benefit.

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20 *Id.* at 29:15-30:2; 34:9-16; 39:18-40:4.

21 Free, Exh. SEF-6 at 35: 33.

22 The relevant statute, RCW 80.28.410 is permissive and allows a utility to "account for and defer for later consideration by the commission costs incurred in connection with major projects in the electrical company's clean energy action plan pursuant to RCW 19.280.030(1)(I)…(2)The costs that an electrical company may account for and defer for later consideration by the commission pursuant to subsection (1) of this section include…(a) [t]he electrical company's authorized return on equity for any resource acquired."

Q. WHAT COMMISSION PRECEDENT DOES PSE PROVIDE IN SUPPORT OF ITS REQUEST FOR A RETURN ON THE DEMAND RESPONSE PPAs?

A. The only instance provided by PSE in response to Public Counsel Data Request No. 054 of "a state utility regulatory commission [] include[ing] a rate of return on PPAs such as that proposed by PSE" is for a Coal Transition PPA, approved in Docket UE-121373. There, the Commission specified that,

> PSE is not entitled to recover an equity return on any other PPA. As the Washington Legislature made clear, this imputed equity return is a unique contract incentive provided by statute exclusively for the purchase of coal transition power as part of the legislative plan to accelerate the retirement of the last remaining coal-fired generating facility in the state of Washington.[23]

The PPA in Docket UE-121373 is insufficient evidence to support PSE's request for return on its DR PPAs. AWEC is further unaware of any Commission decision in which a utility was permitted to earn a return on PPAs.

Q. WHAT IS PSE'S PROPOSAL REGARDING THE PERFORMANCE INCENTIVE MECHANISM ("PIM") RELATED TO DEMAND RESPONSE?

A. PSE's current PIM is based on a DR target of 40 MW by 2024, with an initial reward threshold that activates at 105 percent of the DR target, and a second reward threshold that actives if PSE exceeds 115 percent of the DR target.[24] The DR PIM incentive is currently capped at $1 million over the course of the 2022 MYRP.[25] In this case, PSE is proposing no change to reward thresholds of 105 and 115 percent of the DR target.

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23 Docket No. UE -121373, Order No. 08, at 5-6 ¶ 3 (June 25, 2013).

24 Archuleta, Exh. GA-1T at 18:4-11.

25 *Id.* at 18:14-15.

Notably, PSE provides little support for the reward thresholds and does not plan to update them, stating simply that "[t]hese thresholds were established in the last rate case, and reasonable to continue with them."[26] However, PSE does propose an increase to the PIM target from 40 MW to 149 MW and thus a corresponding increase to the incentive cap from $1 million to $3 million.[27]

Q. DO YOU HAVE CONCERNS WITH PSE'S PROPOSED INCENTIVE CAP OF $3 MILLION?

A. Yes. As explained above, PSE proposes an incentive cap of $3 million over the course of the multiyear rate plan.[28] These "reward thresholds are for all demand response programs in aggregate."[29] PSE's current DR programs that will continue to be eligible under the proposed PIM include Flex Smart, Flex Rewards, Flex Events, and Business Demand Response.[30] However, PSE proposes to include more DR programs than previously eligible under the PIM, specifically, "pricing programs design to shift load from peak periods and resource system peak demand," and any "[a]dditional DR resources procured through PSE's ongoing efforts – in addition to existing contracts."[31] Because PSE has increased the scope of PIM eligible programs, and because the proposed $3 million cap applies to all DR programs in the aggregate, the likelihood that shareholders will receive a benefit correspondingly increases. This incentive structure

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26 Mullins, Exh. BGM-4 (PSE Response WUTC DR 066(c)).

27 Archuleta, Exh. GA-1T at 19:11-12; 21:12-13.

28 *Id.* at 20:11-12.

29 Mullins, Exh. BGM-4 (PSE Response WUTC DR 066(b)).

30 Exh. GA-1T at 18:17-19:3; 15-16.

31 *Id.* at 19:17-19.

underscores the unreasonable nature of shareholders also earning a return on the DR PPAs.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject PSE's request for return on CETA-compliant Demand Response PPAs. The impact of my recommendation is a $1,271,326 reduction to power supply expenses in RY 1 and an additional $93,588 reduction in RY 2. I further recommend that the Commission retain the current PIM incentive cap of $1 million. Given the expanded scope of PSE's proposed PIM, additional incentives for shareholders are not warranted. When considered together, PSE's customers could be asked to pay a $4.36 million premium on PSE's demand response programs with no incremental benefit to customers. PSE has provided no credible rationale for why customers should be burdened with paying the Company's shareholders significant financial incentives for demand response programs, particularly in light of the Company's obligation to include demand response targets in its Clean Energy Implementation Plans as a pathway for meeting CETA's clean energy requirements.

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes.