BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKETS UE-240004 & UG-240005 (Consolidated)

CROSS-EXAMINATION EXHIBIT OF BRENNAN D. MUELLER
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT BDM-__X

Direct Testimony of Brennan D. Mueller

October 28, 2024

EXH. BDM-1T
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: BRENNAN D. MUELLER

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-240004** **Docket UG-240005**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

BRENNAN D. MUELLER

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF BRENNAN D. MUELLER

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy.

A. My name is Brennan D. Mueller, and my business address is 355 110th Avenue NE, Bellevue, Washington 98004. I am the Manager Power Costs & Energy Analysis for Puget Sound Energy ("PSE").

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

A. Yes. Please see the first exhibit to the Prefiled Direct Testimony of Brennan D. Mueller, Exh. BDM-2 for my professional qualifications.

Q. What are your duties as Manager Power Costs & Energy Analysis?

A. As Manager Power Costs & Energy Analysis my primary responsibilities include:

(i) providing analytical support and performance reporting for PSE's Energy Supply Merchant operations, and

(ii) forecasting power costs and natural gas supply costs for PSE financial planning and regulatory filings.

Q. Please summarize the contents of your testimony.

A. First, I provide a general overview of power costs and PSE's power cost adjustment ("PCA") mechanism. I then present forecasted power costs for the 2025 and 2026 rate period in this proceeding along with a comparison to power costs currently in customer rates and a discussion of key factors driving year-over-year forecast changes. Next, I describe PSE's power cost forecast methodology, including recent changes to that methodology and PSE's approach to calculating the effect of Washington State's Climate Commitment Act ("CCA") "cap-and-invest" program on forecasted power costs. I then discuss major assumptions and inputs to PSE's power cost forecast and the source or rationale for these inputs. Finally, I discuss the need for regular updates to the power cost forecast included in rates and propose continuation of the annual power cost update process approved in PSE's 2022 General Rate Case, Dockets UE-220066/UG-220067 et al, with some modifications.

II. POWER COSTS BACKGROUND

Q. What is included in PSE's power costs?

A. In general, power costs include the cost of fuel used to generate electricity and the net cost of electric power that PSE purchases to meet the demand of its retail electric customers. More specifically, these expenses include the cost of coal, gas, and oil to operate thermal generators; costs of fuel transportation and storage; purchased transmission capacity; power purchase agreements ("PPA"); wholesale power market purchases, and various other costs incurred directly in connection with the management of PSE's electric supply portfolio. Power costs also include the benefit of revenue from wholesale power market sales of surplus electric supply as well as revenue from the sale or optimization of any surplus transmission, fuel transportation, or fuel storage capacity. Power costs do not include fixed production costs for rate base and operations or maintenance expense associated with PSE-owned power supply resources. Such costs and their impacts to PSE's revenue requirement are presented in the testimonies of Susan E. Free, Exh. SEF-1T, and Mark A. Carlson, Exh. MAK-1CT.

Q. How are the power costs incurred by PSE recovered in customer rates?

A. The power costs described herein include costs identified as variable power costs according to PSE's PCA mechanism.[1] The PCA establishes a baseline rate using a

[1] "Other power supply costs" chargeable to FERC account 557 are included in the power costs presented herein but, except for the cost of demand response contracts and a small portion of 557 expenses attributable to brokerage fees, are not included in the PCA variable baseline rate.

forecast of variable power costs. Differences between actual variable power costs and the power costs recovered via the variable baseline rate are tracked and allocated to customers according to the PCA sharing bands. Generally, if actual power costs are higher than the power cost forecast used to establish the baseline rate there will be a PCA under-recovery and potentially a surcharge in future customer rates. If actual power costs are lower than the power cost forecast used to establish rates there will be a PCA over-recovery and potentially a credit in future customer rates.

Q. How are variances between actual variable power costs and power costs recovered via the variable baseline rate shared between the company and customers?

A. PSE's PCA mechanism originally took effect on July 1, 2002, following a settlement agreement that originated in PSE's 2001 general rate case.[2] As part of PSE's 2013 power cost only rate case, Docket UE-130617, PSE and parties to that proceeding initiated a collaborative that resulted in a multiparty settlement updating certain elements of the PCA, including how variances are shared between PSE and customers. The settlement identifies three graduated levels of annual power cost variance, or bands, according to which variances are shared. The "dead band" includes the first $17 million of power cost variance (positive or negative). Within the dead band, 100 percent of costs or benefits are retained by PSE. The first sharing band includes power cost variances between $17 and $40

[2] Dockets UE-011570/UG-011571 and UE-011411 (consolidated),

million (positive or negative). Within this band, costs (under-recoveries) are shared 50 percent to PSE and 50 percent to customers while benefits (over-recoveries) are shared 35 percent to PSE and 65 percent to customers. The second sharing band includes power cost variances over $40 million (positive or negative). All variances in this band are shared 10 percent to PSE and 90 percent to customers, regardless of whether they are costs or benefits.

The customers' share of power cost variances is accounted for each year and deferred until a cumulative balance in the deferral account triggers a refund or allows a surcharge. A refund or surcharge can occur if the cumulative deferred customer share of imbalances exceeds $20 million.

Q. Why do actual power costs vary from the forecasts used to establish the variable baseline rate?

A. Actual power costs reflect the realized outcome of multiple interrelated variables that often fluctuate considerably from year to year or month to month, or even hour to hour. Many of these variables are weather-dependent and difficult to predict or forecast accurately for a specific period in the future. PSE's power cost forecast and the resulting baseline rate assume outcomes for these variables will be "normal" – generally equal to long-term historical averages or expected values given other normalizing assumptions. When actual conditions inevitably vary from normal conditions, actual power cost results will vary from the forecast included in rates causing variable power costs to be over-recovered or under-recovered in any particular year. However, these annual variances due to changes in weather-dependent variables should be expected to balance out over time such that they do not cause large *accumulated* over- or under-recoveries.

Q. Do other factors cause actual power costs to vary from the forecasted power costs included in rates?

A. Yes. The timing of when a power cost forecast is established and when that forecast is effective in the baseline rate can create significant variances between the costs included in rates and actual results. PSE's power cost forecast includes the portfolio of electric supply resources that is known at the time the forecast is created. Only new resources for which PSE has executed a PPA or received board approval to acquire are included in the forecast. In other words, the forecast does not include the cost of new resources unless those costs are reasonably known and measurable. If PSE adds new resources to the portfolio after the forecast is established, then the power cost impact of such resources will not be reflected in the PCA variable baseline rate. A mismatch between the resources assumed in the forecast and those actually available during a rate-effective period will cause power cost over- or under-recoveries. The potential for such mismatches and their impacts are amplified if PSE is rapidly acquiring new resources – as is currently the case given ambitious clean energy requirements and PSE's resource adequacy and reliability needs discussed in the Prefiled Direct Testimonies of Ronald J. Roberts, Exh. RJR-1T, Joshua J. Jacobs, Exh. JJJ-1T, and Philip Haines, Exh. PAH-1CT. A power cost forecast that is updated as near as practical to the start of a rate effective period more closely aligns the forecasted resource portfolio with resources actually used to meet electric demand and helps ensure that the power costs included in rates are estimated "as closely as possible to costs that are reasonably expected to be actually incurred."[3]

Q. When are PSE's power cost forecast and variable baseline rate established?

A. Historically, power costs included in customer rates have been established or updated in a general rate case or power cost only rate case ("PCORC") proceeding. These are relatively long-duration proceedings with rate-effective periods typically beginning at least 11 months after a general rate case is filed and at least six months after a PCORC is filed. These rate cases occurred relatively infrequently and at irregular intervals, meaning that rates established based on a forecast for a particular rate year often remained in effect for subsequent years that were not included in the forecast period.

For example, PSE updated the power cost baseline rate in its 2017 General Rate Case based on a forecast of power costs for calendar year 2018 and the resource portfolio known as of January 2017. This baseline rate remained in effect until October 15, 2020. PSE updated the baseline rate in its 2020 PCORC based on a forecast of power costs for the 12 months ending May 31, 2022, and the resource portfolio known as of December 2020. This baseline rate was in effect from July 1, 2021, until early January 2023. These mismatches between the time and period for which power cost forecasts were established and the time they were included

[3] *WUTC v. Puget Sound Energy, Inc.,* Docket UE-040640, *et al.,* Order 06 at ¶ 108 (Feb. 18, 2005).

in rates contributed to significant PCA under-recoveries in 2019 through 2022 and subsequent customer rate surcharges. In its 2022 General Rate Case PSE presented arguments supporting a need for routine updates to the power cost forecast included in rates and proposed a process for updating the PCA variable baseline rate on an annual basis.[4] The settlement agreement and Commission's final order[5] in that case called for an update to PSE's 2023 power cost forecast at the end of 2022 to establish the 2023 baseline rate and an update to PSE's 2024 power cost forecast 90 days prior to the end of 2023 to establish the 2024 baseline rate. Section VI of my testimony proposes continuation of these annual updates to PSE's power cost forecast and variable baseline rate along with some modifications relative to the process spelled out in the 2022 General Rate Case revenue requirement settlement.

III. POWER COSTS IN THIS PROCEEDING

Q. What is the basis for the power cost rates that are in place today?

A. Power costs included in the current PCA variable baseline rate were established pursuant to PSE's 2024 power cost update filed in accordance with the settlement agreement and Commission's final order in PSE's 2022 General Rate Case. PSE filed its proposed update to 2024 power costs on September 29, 2023. On December 22, 2023, the Commission issued its Final Order 01 in Docket UE-230805 rejecting in part PSE's proposed 2024 power costs and ordering and

[4] Exh. JKP-1T in Docket UE-220066.

[5] Docket UE-220066 & UG-220067, et al., Final Order 24/10, Appendix A "Revenue Requirement Settlement," at ¶ 29.

authorizing a compliance filing. On December 27, 2023, PSE submitted its compliance filing with revised tariff sheets incorporating adjustments to forecasted 2024 power costs consistent with the Commission's order. These adjustments included a forecast reduction for estimated power cost benefits associated with demand response contracts and removal of estimated power cost impacts associated with the CCA cap and invest program. Rates included in PSE's December 27 compliance filing went into effect on January 1, 2024.

Q. What is PSE's current forecast of power costs for calendar years 2025 and 2026?

A. PSE's current forecast of power costs for 2025 is $983 million. This is $134 million, or 12 percent, lower than the amount in rates for calendar year 2024. PSE's current forecast of 2026 power costs is $1,096 million, approximately 12 percent higher than forecasted 2025 power costs and about two percent lower than the amount in rates for calendar year 2024. Table 1 below provides a summary of the power cost forecast for 2025 compared to the 2024 forecast currently in rates, organized by FERC[6] account and resource category.

[6] Federal Energy Regulatory Commission. Power costs included in the PCA variable baseline rate are generally identified according to FERC accounting categories.

Table 1. 2025 power cost forecast versus 2024 forecast currently in rates ($ in thousands)

FERC acct category	($ in thousands)	2025 forecast	2024 forecast (in rates)	2025 increase / (decrease)
501	Coal fuel	$46,933	$55,532	($8,599)
547	Natural gas fuel	$532,758	$324,050	$208,708
555WS	Wind and solar purchases	$79,582	$76,718	$2,864
555H	Hydro purchases	$356,334	$275,779	$80,555
555	Other contract purchases	$279,131	$421,046	($141,915)
555MP	Market purchases	$122,698	$157,150	($34,451)
447	Secondary sales	($506,401)	($249,030)	($257,371)
565	Transmission	$162,468	$153,227	$9,241
456	Other revenues	($130,054)	($126,901)	($3,153)
557DR	Demand Response	$16,618	$11,391	$5,227
557	Other power supply expense	$22,547	$17,154	$5,393
	Total Power Costs	**$982,613**	**$1,116,116**	**($133,503)**

Exhibit BDM-3C provides a summary of PSE’s current forecast of power costs for calendar years 2025 and 2026, including monthly detail for each of the line items included in Table 1 above. See Exh. BDM-4C for a summary of the 2025 and 2026 power cost forecasts by individual resource or cost item.

Q. Why are forecasted 2025 power costs lower than the 2024 power cost projection currently in rates?

A. PSE’s current forecast of 2025 power costs is lower than the 2024 power cost forecast primarily due to projected changes in the market price of natural gas and electricity and changes to PSE’s electric resource portfolio.

A. Market Prices of Natural Gas and Electricity

Q. How do projected market prices for natural gas and electricity in PSE's 2025 power cost forecast compare to market prices in the 2024 forecast?

A. Projected market prices for natural gas and electricity used in PSE's forecast of 2025 and 2026 power costs are higher than prices projected for calendar year 2024. On average, market electricity prices in 2025 are more than 30 percent higher than projected prices for 2024. Natural gas prices in the 2025 forecast are approximately seven percent higher than natural gas prices in the 2024 forecast. The projected market price of electricity relative to the market price of natural gas, a measure referred to as the market heat rate, is considerably higher (more than 20 percent) in 2025 and 2026 than the market heat rates assumed in PSE's 2024 power cost forecast. Market heat rates are a critical variable in determining whether or not gas-fired generation units will be dispatched. Higher market heat rates make gas-fired generators more economic to run, which in turn reduces the amount of energy PSE needs to purchase from the wholesale spot market and/or increases the amount of energy PSE can sell in the wholesale spot market. See Exh. BDM-5C for projected monthly prices of natural gas and electricity in 2025 and 2026 and comparisons to the prices used in PSE's 2024 power cost forecast.

Q. Why are higher market heat rates reducing PSE's 2025 power cost forecast relative to the 2024 forecast?

A. Higher market heat rates make it more economic to run PSE's gas-fired generators, which reduces the amount of power PSE purchases in the wholesale market and increases the amount of surplus energy supply that PSE can sell in the wholesale market. This net change in wholesale market purchases and sales reduces net forecasted power costs. The net cost of PSE's wholesale spot market transactions in the 2025 forecast is approximately $292 million lower than the net cost of these transactions in the 2024 forecast. This lower net cost of market purchases and sales is offset by only a $208 million increase in the forecasted cost of fuel for PSE's natural gas fired generators.

Q. How does forecasted utilization of PSE's gas-fired generators in the current forecast compare to historical utilization of these resources?

A. PSE's gas-fired generation fleet is currently forecasted to generate more than ten million MWh in 2025, an increase of approximately 43 percent compared to the 2024 forecast. Between 2017 and 2022 these same generators produced on average only 5.7 million MWh per year. While higher production from PSE's gas-fired generators provides direct benefits to forecasted power costs in 2025 and 2026, this higher utilization is also likely to increase costs in other areas. Power costs presented herein do not include higher operations and maintenance expense associated with increased use of these generators nor do they include any direct cost associated with emissions allowances that may need to be purchased to comply with the CCA cap and invest program. The Prefiled Direct Testimony of Mark A. Carlson, Exh. MAC-1CT, discusses operation and maintenance expense for PSE's gas-fired generators. The effect of the CCA on PSE's operation of its gas-fired generation fleet and the impact to forecasted power costs are discussed in Section IV of my testimony below.

B. Resource portfolio changes

Q. What changes to PSE's resource portfolio are driving the 2025 power cost forecast reduction relative to 2024?

A. PSE's 2025 power cost forecast includes the addition of three new intermediate to long-term power supply resources that were not included in the 2024 forecast. It also reflects the expiration of three shorter-term PPAs that were included in the 2024 forecast. New resource additions include:

i. The Beaver Creek wind project, a 248 MW PSE-owned wind generation facility located in Montana with production expected to begin in August 2025. Colin Crowley discusses the Beaver Creek wind project and PSE's decision to acquire this resource in Exh. CPC-1HCT.

ii. The Vantage Wind PPA, a power purchase agreement for output from a 90 MW wind facility in central Washington beginning in October 2025. Colin Crowley discusses the Vantage Wind PPA and PSE's decision to acquire this resource in Exh. CPC-1HCT.

iii. The Freddy 1 Tolling Agreement, an agreement to schedule and purchase the output from approximately 50 percent of the 265 MW Frederickson combined cycle natural gas-fired facility in western Washington beginning in October 2025. Steven St. Clair discusses the Freddy 1 Tolling Agreement and PSE's decision to acquire this resource in Exh. SJS-1CT.

Expiring PPAs excluded from the 2025 forecast but active in 2024 include:

i. A 250 MW PPA with Powerex for summer peak energy and capacity that expires September 30, 2024, and

ii. Two 250 MW PPAs with Powerex for winter peak energy and capacity that both expire March 31, 2024.

Please see Exh. BDM-6C for a complete list of electric supply resources included in PSE's current known portfolio for 2025 and 2026, along with comparisons to the electric supply resources included in PSE's 2024 power cost forecast.

Q. What is the impact of these resource changes to PSE's 2025 power cost forecast?

A. Inclusion of the resource additions and expirations listed above in PSE's power cost model reduces forecasted 2025 power costs approximately $76 million. A little more than half of this reduction, or $39 million, is attributable to the new resource additions. The remaining $37 million is due to expiration and removal of the Powerex summer and winter peak PPAs.

Q. Why do new resource additions reduce PSE's 2025 power cost forecast?

A. The effect of new resource additions on PSE's power cost forecast depends on multiple factors, including the volume and timing of energy delivered from the resource, the market price of electricity, the cost of fuel in the case of a non-renewable resource, the contract price or payment terms in the case of a PPA, and whether the resource is owned by PSE or acquired via PPA. The distinction between PSE-owned resources and those acquired via PPA is a critical one in determining how a particular resource addition will affect PSE's power costs.

Q. How do new PSE-owned resources affect PSE's power cost forecast?

A. With PSE-owned resources there are no direct costs included in the power cost forecast (except for fuel in the case of natural gas or coal fueled generators). Production costs for rate base and operations and maintenance expense are not included in the power cost forecast. The effect on power costs of adding a new PSE-owned resource like Beaver Creek, therefore, is always to reduce the forecast relative to what it would have been absent the resource. This occurs because the energy from the resource is included in the forecast at no cost but still either reduces the volume of energy that PSE purchases from the electric spot market (lowers "Market purchases" cost) and/or increases the volume of energy that PSE sells into the electric spot market (increases "Secondary sales" revenue). Generally, the power cost impact of adding a new PSE-owned resource is a forecast reduction equal to the energy supplied from the resource multiplied by the market electricity price in the forecast period (minus the cost of fuel for the resource, if any). The power cost impact of adding Beaver Creek to PSE's portfolio is a $30.8 million reduction to the 2025 forecast and a $53.7 million reduction to the 2026 forecast.

Q. How do new PPAs affect PSE's power cost forecast?

A. PPAs are different from PSE-owned resources in that the entire cost of a PPA is included in the power cost forecast as purchased power expense (FERC account 555). So, while the energy provided by a PPA reduces market purchases cost and/or increases secondary sales revenue in PSE's forecast just like a PSE-owned resource, this reduction to the forecast is offset by the cost of the PPA. If the cost of the PPA is greater than the benefit from reduced market purchases and/or increased secondary sales, the result will be a net increase to forecasted power costs. If the cost of the PPA is less than the benefit from reduced market purchases and/or increased secondary sales, the result will be a net reduction to forecasted power costs. The power cost impact of adding the Vantage Wind PPA to PSE's portfolio is a $1.6 million reduction to the 2025 forecast and a $3.3 million reduction to the 2026 forecast. The power cost impact of adding the Freddy 1 Tolling Agreement to PSE's portfolio is a $6.4 million reduction to the 2025 forecast and a $15.4 million reduction to the 2026 forecast.

Q. Does the estimated power cost impact of new resources reflect all the benefits of these resources?

A. No. The power cost impact of adding a new resource only reflects benefits from the reduction to market energy purchases or increase to secondary market sales that result when the resource is included in PSE's portfolio. New resources are regularly selected based on expected benefits that do not show up as a direct reduction to forecasted power costs. Such benefits often include meeting a resource adequacy (reliability) need for new capacity, or achieving renewable energy goals or requirements under the state's Clean Energy Transformation Act ("CETA").

New PPA resources that provide these benefits are potentially more expensive than the spot market energy purchases they displace in PSE's power cost model and would therefore increase forecasted power costs. This would not be an indication that the overall net benefits provided by the resource are negative when compared to alternative resources that could fulfill the same need. PSE's power cost forecast does not include placeholders for such alternative new capacity or clean energy resources, even if PSE anticipates such resources will be needed during the forecast period. The forecast only includes new resources for which PSE has signed contracts or are otherwise reasonably known and measurable at the time the forecast is prepared. This means that the power cost forecast model implicitly assumes PSE's resource portfolio has sufficient capacity and renewable energy to meet reliability and clean energy requirements during the forecast period. This is a reasonable assumption for a model intended to forecast power costs in the near term. PSE is likely to have acquired much of the capacity and or renewable energy it needs for a particular calendar year by just prior to the start of that year. However, when the period being forecasted is well in advance of the time a forecast is prepared, PSE is less likely to have acquired the new resources it will need and the cost of needed new resources will not be reflected in the forecast.

Q. Why does expiration of the Powerex summer and winter peak PPAs reduce PSE's 2025 power cost forecast?

A. The cost of the Powerex summer and winter peak PPAs is higher than the forecasted 2025 market energy price in PSE's power cost model. When these resources are removed from the model, they are replaced with lower cost market purchases, causing a net reduction to the power cost forecast. This impact on the current forecast does not account for any replacement capacity or renewable energy that PSE may still need to acquire to replace the reliability and clean energy benefits provided by the Powerex PPAs. As stated above, PSE only includes such new resources and associated costs in its forecast if contracts for the new resource have been executed or the costs are otherwise known and measurable.

Q. What are the primary drivers of higher forecasted power costs in 2026 relative to 2025?

A. The current forecast of 2026 power costs includes projected market prices that are similar to the 2025 forecast and does not include any new resources relative to 2025. The primary driver of projected higher 2026 power costs compared to 2025 is the removal of coal-fired resources from the portfolio at the end of 2025 as required by CETA. This change includes removing approximately 370 MW of capacity from Colstrip units 3 and 4 as well as more than 300 MW of capacity from PSE's PPA for output from the Centralia coal-fired power plant. Replacing the energy provided by Colstrip units 3 and 4 with wholesale spot market energy purchases increases forecasted 2026 power costs approximately $146 million. This estimate does not include the potential cost of replacing capacity and resource adequacy benefits currently provided by Colstrip units 3 and 4.

C. Potential New Resources Not Currently Included in the Forecast

Q. Are PSE's current power cost forecasts for 2025 and 2026 an accurate representation of the power costs PSE expects to incur in those years?

A. No. The forecasted 2025 and 2026 power costs presented above incorporate the most up-to-date information available regarding market prices and the PSE power supply portfolio when PSE finalized assumptions in its power cost model on November 15, 2023. While current market conditions and the existing PSE portfolio can provide a reasonable basis for projecting power costs in the near term, the forecast for 2025 and 2026 is for a period that is between thirteen and twenty-five months away from the time the forecast was prepared. It is very unlikely that the assumptions in PSE's current forecast of 2025 and 2026 power costs will remain the most accurate assumptions available at the end of this proceeding or shortly prior to the start of 2026.

Q. Does PSE expect to acquire new resources that are not included in the current 2025 and 2026 power cost forecast presented above?

A. Yes. PSE anticipates adding new resources to its portfolio that will be effective or in service during 2025 and 2026 but have not yet been specifically identified or for which contracts have not yet been signed. Such new resources will be necessary to meet the capacity needs identified in PSE's 2023 Integrated Resource Plan Electric Progress Report, comply with the planning standards of the Western Resource Adequacy Program ("WRAP"), and to meet the clean energy targets of CETA. These anticipated new resources are incremental to the power supply portfolio assumed in the current forecast of 2025 and 2026 power costs and their impacts are not reflected in that forecast.

Q. What new resources does PSE expect to acquire in the near term?

A. PSE is currently working to finalize agreements to purchase or acquire the output from 34 individual distributed energy resources ("DER") that may begin delivering energy, capacity, and clean energy benefits to PSE's portfolio as early as June 2024. PSE expects output from 33 out of the 34 resources will be acquired via PPA while PSE would purchase and own one of them. These resources are all relatively small (five MW or less) solar, battery, or hybrid solar-plus-battery installations located within PSE's service territory. These new resources are not included in PSE's current power cost forecast because contracts have not yet been executed, but PSE anticipates finalizing all or most of these agreements during the first quarter of 2024. An update to PSE's power cost forecast near the end of this proceeding would include these new resources, assuming they are finalized by that time. The Prefiled Direct Testimony of Gilbert Archuleta, Exh. GA-1T, provides additional detail regarding PSE's acquisition of DERs.

Q. Has PSE estimated the likely impact of these DERs on forecasted power costs for 2025 and 2026?

A. Yes. Based on expected final terms for each of these 34 new DERs, PSE projects an approximately $3 million increase to the current forecast of 2025 power costs and an approximately $24 million increase to the current forecast of 2026 power costs.

Q. Does PSE expect to acquire other new resources in the near term?

A. Yes. PSE will need to acquire both new capacity resources and new renewable energy supply to meet its near term resource adequacy and clean energy needs. PSE has not yet entered agreements or identified specific resources to meet these needs, so the cost of acquiring them is not reflected in the current forecast of 2025 and 2026 power costs. PSE is actively pursuing resources to meet these near term needs and anticipates many needed for 2025 will have been acquired prior to the start of that year. Many needed for 2026 will likely not have been acquired until closer to the start of that year. An update to PSE's power cost forecast near the end of this proceeding and further updates prior to the beginning of each calendar year thereafter would help make sure such new resources are included in forecasted power costs and accurately reflected in the PCA baseline rate.

Q. Has PSE estimated the likely impact of these potential new resources on forecasted power costs for 2025 and 2026?

A. Yes. PSE expects its 2025 and 2026 power cost forecast will increase substantially when new resources to meet near term capacity and clean energy needs are acquired and added to the portfolio. The estimated increase to 2025 power costs relative to the current forecast is between $88 million and $167 million. The estimated increase to 2026 power costs is between $144 million and

$285 million. PSE has not yet identified the specific resources that will be used to meet its projected 2025 and 2026 capacity and clean energy needs, so these are not precise estimates. Nonetheless, they illustrate that changes to PSE's resource portfolio between now and the time rates go into effect for 2025 and 2026 will cause significant changes to PSE's forecasted power costs—and actual power cost results—relative to the current forecast which does not account for these changes.

IV. POWER COST FORECAST METHODOLOGY

A. Power Costs Methodology Overview

Q. How did PSE estimate 2025 and 2026 power costs?

A. As in prior cases, PSE used the Aurora dispatch model to forecast spot market electric power prices and project a portion of its power costs for the rate period in this proceeding. PSE calculated the remaining rate period power costs outside the Aurora model and refers to these power costs as "Costs not in Aurora." The power cost forecast methodology PSE used to calculate the current forecast of 2025 and 2026 power costs presented above is the same methodology PSE used to calculate 2024 power costs currently in rates, with two qualifications regarding the power cost benefits of demand response contracts and indirect costs of the CCA cap and invest program. I discuss these in more detail below.

Q. What costs does the Aurora dispatch model project?

A. Aurora projects variable costs of fuel for PSE resources, most long-term PPAs, and spot market purchases and sales to balance available energy with energy demand. See Exh. BDM-7C for monthly detail of the power cost outputs from the Aurora model for 2025 and 2026 as well as projected electric energy volumes from each resource in PSE's portfolio.

Q. Did PSE make changes to the Aurora dispatch model relative to the model used in PSE's 2022 General Rate Case and 2024 power cost update?

A. Yes. Energy Exemplar, the developer of the Aurora model, provides periodic software and database updates. The software version of Aurora used in this filing is Version 15.0.1004, which Energy Exemplar released in September 2023. The database used is Aurora WECC Zonal V23.11, which Energy Exemplar issued in November 2023. PSE's 2024 power cost update used Aurora Version 14.2.1001 and the Aurora WECC Zonal 2020.1.0.1 database.

Q. What power costs are calculated outside of the Aurora model?

A. Power costs that are calculated outside of the Aurora model include transmission costs, fixed gas transportation costs, fixed costs associated with certain PPAs (including Mid-Columbia hydroelectric contracts), the value or benefit of upstream gas pipeline capacity and gas storage, various other adjustments to Aurora cost outputs, and the incremental cost or benefit of previously executed short-term power and gas-for-power contracts. See Exh. BDM-8C for a summary of all not-in-Aurora costs.

Following the same convention as with intermediate and long-term new resource contracts, previously executed short-term power contracts include only those in place as of the time the current forecast of 2025 and 2026 power costs was prepared (November 15, 2023). These contracts and PSE's calculation of their incremental costs or benefits are provided in Exh. BDM-9C.[7] Exhibits introduced throughout the remainder of my testimony provide support and detail for the calculation of all other not-in-Aurora costs.

B. Methodology changes in this proceeding

Q. How is PSE's power cost forecast methodology different from that used to calculate 2024 power costs currently in rates?

A. On December 22, 2023, the Commission issued its Final Order 01 in Docket UE-230805, rejecting in part PSE's proposed 2024 power costs and ordering and authorizing a compliance filing with certain adjustments to the forecast. Those adjustments were to include estimated power cost benefits from demand response contracts in the forecast and to remove estimated indirect power costs associated with the CCA cap and invest program from the forecast. PSE's forecast of 2025 and 2026 power costs includes demand response contract benefits according to the same methodology used to calculate such benefits in PSE's final 2024 power cost forecast consistent with the Commission's Final Order 01. PSE's forecast of 2025 and 2026 power cost includes indirect costs associated with the CCA cap and invest program according to the same methodology used to calculate the 2024

[7] Exh. BDM-9C also includes the calculation of fixed costs for certain PPAs that have a fixed-cost component in the total price.

indirect costs rejected by the Commission for inclusion in PSE's 2024 power cost forecast.

Q. How are the benefits of demand response contracts included in PSE's forecast of 2025 and 2026 power costs?

A. PSE's power cost forecast estimates the benefits of demand response contracts assuming demand response capability is deployed to its fullest extent during hours with the highest forecasted demand. These highest demand hours generally coincide with high market power prices. The reduction to forecasted power costs attributable to demand response contracts is equal to the amount of demand reduction in a particular hour multiplied by the forecasted market price of electricity in that hour. The benefits of demand response contracts therefore show up as a reduction to the cost of market purchases in PSE's forecast. This reduction to market purchases is not equivalent to the full benefit of demand response contracts. Like other resource additions, these contracts provide resource adequacy or reliability benefits relative to alternative resources. But this benefit is not explicit in power costs because, as discussed earlier in my testimony, PSE's power cost model does not include alternative new capacity resources or placeholder capacity costs for the demand response contracts to displace. The estimated reduction to market purchases due to demand response contracts and the cost of PSE's demand response contracts in 2025 and 2026 are found in Exh. BDM-10C.

Q. What costs associated with the CCA cap and invest program did PSE include in its power cost forecast for 2025 and 2026?

A. PSE's power cost forecast includes estimated impacts of the CCA resulting from changes to resource dispatch that cause a net increase to forecasted power costs. PSE reflected these indirect costs as the net result of a decrease to forecasted secondary sales revenue partially offset by a decrease in the cost of fuel for PSE's gas-fired generators. PSE's power cost forecast does not include any direct costs of allowance purchases that may be required to comply with the CCA. PSE will defer any such costs pursuant to the accounting petition approved in Docket UE-220974.

Q. How does PSE estimate the CCA impact on resource dispatch and resulting change to forecasted secondary sales and fuel costs?

A. PSE first dispatches its resources in the Aurora model without including any CCA costs in the dispatch logic for the resources. PSE then compares resulting monthly energy supply volumes from all PSE resources to monthly PSE retail electric demand outside of the Aurora model to determine how much of the generation from PSE's emitting resources would not be eligible for no-cost allowances allocated by the Department of Ecology. The portion of generation not eligible for no-cost allowances is that which exceeds PSE retail demand and therefore would be used to supply wholesale market sales. PSE assumes it must buy allowances for emissions from any of the generation used to supply wholesale market sales, so these sales are only beneficial if the revenue generated from them is sufficient to cover costs of fuel *and* the cost of emissions allowances.

The calculation then compares average revenue from wholesale market sales to the average fuel cost of generation used to supply them. If this difference—effectively the margin on wholesale market sales before any allowance costs—is less than the cost of buying allowances, then those sales should not have been made and their impact is adjusted out of the power cost forecast. This adjustment removes the secondary sales revenue from any such uneconomic sales and removes the cost of fuel used to generate them. Exhibit. BDM-11C contains the details and steps used to calculate this adjustment.

Q. What is the impact to PSE's forecast of 2025 and 2026 power costs from this adjustment for the CCA cap and invest program?

A. The calculated adjustment described above increases PSE's forecast of 2025 power costs by $4.1 million. This is the net result of an $11.5 million reduction to secondary sales revenue and a $7.4 million reduction to fuel costs. The adjustment increases PSE's forecast of 2026 power costs by $4.8 million. The estimated impact in both years is less than the estimated impact to PSE's 2024 power cost forecast, which was $22.7 million.

Q. Why is the estimated power cost impact from considering CCA costs in dispatch decisions lower in 2025 and 2026 than in 2024?

A. The effect on power costs of considering CCA allowance costs in PSE's dispatch decisions depends on market prices and heat rates, retail electric demand, energy supply from non-emitting or renewable resources, and the price of emissions allowances. Forecasted indirect power costs associated with the CCA are lower in 2025 and 2026 primarily due to higher market heat rates and lower assumed emissions allowance prices. As discussed earlier in my testimony, market heat rates in 2025 and 2026 are much higher than projected 2024 heat rates. These higher power prices relative to the price of natural gas make it more economic to run gas-fired generation and increase the margin on projected wholesale market sales of gas-fired generation. When that margin is greater than the cost of emissions allowances, gas-fired generators will be dispatched regardless of whether or not CCA allowance costs are included in the dispatch decision and there will be no impact to power costs. This is frequently the case in PSE's 2025 and 2026 forecast. Further, assumed emissions allowance prices in PSE's 2025 and 2026 power cost forecast are lower than those assumed in the 2024 forecast. The 2024 forecast assumed an allowance price of $70.50 per metric ton of CO2-equivalent based on the secondary market index price as of September 5, 2023. The allowance price assumed for 2025 in PSE's current power cost forecast is $57.91 per metric ton based on the same index as of November 15, 2023.

Q. What is the rationale behind PSE's methodology for estimating indirect power costs associated with considering CCA costs in dispatch decisions?

A. PSE's methodology for estimating the impact of the CCA on resource dispatch and power costs is consistent with PSE's current understanding of Washington Department of Ecology's no-cost emissions allocation process and how PSE is actually dispatching its resources at this time. According to its current understanding of the no-cost allowance allocation and adjustment process, PSE receives no-cost allowances only for emissions from PSE generation and market purchases used to serve its retail electric demand. PSE must purchase allowances for any emissions from emitting resources that generate electricity sold in the wholesale market or delivered to other utilities. This means that PSE will not incur allowance purchase costs for emissions associated with serving retail demand but will incur allowance purchase costs for emissions associated with wholesale market sales. To minimize total electric supply costs, only costs that will actually be incurred should be considered in resource dispatch decisions. Therefore, CCA allowance costs need to be considered in dispatch decisions when generation is sold in the wholesale market but do not need to be considered when generation is used to meet retail demand.

Q. Does PSE consider CCA allowance costs in its actual resource dispatch decisions?

A. Yes. PSE considers the cost of CCA allowances in its actual resource dispatch decisions in a manner functionally equivalent to how such costs are considered in

PSE's forecast methodology and with the same objective – to guarantee that emitting generation is only sold into the wholesale market if revenue from such sales is sufficient to cover the cost of emissions allowances. To do this, PSE must differentiate between the dispatch of emitting resources to serve retail demand and the dispatch of emitting resources to supply wholesale market sales. In a forecast that includes perfect foresight of load, variable resource output, and market prices, this is fairly straight-forward. In actual operations, however, these variables are constantly changing and often difficult to forecast. Dispatch decisions made in advance based on a forecast of which resources will be used to serve retail load may appear sub-optimal after the fact as actual load, variable resource output, and market power prices differ from forecast. PSE currently relies on month-ahead forecasts of resource availability and retail demand to estimate which portion of its total electric supply will be used to supply wholesale sales and then includes a CCA allowance cost adder in the dispatch decision for that portion of the electric supply portfolio.

Q. Does PSE expect to incur indirect power costs in 2024 because it considered CCA allowance costs in its actual dispatch decisions?

A. Yes. PSE presented the forecast of the 2024 power cost increase associated with considering CCA allowance costs in dispatch decisions in PSE's forecast of 2024 power costs filed on September 29, 2023 (but later rejected by the Commission for inclusion in PSE's 2024 power cost baseline rate). PSE has not revised its forecast of expected 2024 power cost impacts since that time, but actual impacts are likely to be lower, given the recent decline in CCA allowance prices. Just like the forecast, however, actual results will depend on actual market prices for electricity, fuel, and CCA allowances as well as actual retail demand and energy supplied by other resources.

Q. Did PSE incur indirect power costs from including CCA allowance costs in actual resource dispatch decisions in 2023?

A. Yes. But they were minimal, due to actual market conditions (very high heat rates/prices), and difficult to quantify – requiring the following counterfactual scenario: how would PSE have dispatched its resources absent CCA costs, and how would those different decisions have affected ultimate power cost results? It obviously involves many complex and interrelated variables. PSE continues to work on developing a reasonable methodology, but it will be imperfect, at best.

C. Methodology changes introduced in PSE's 2024 power cost update

Q. Did PSE make any changes to its forecast methodology in the 2024 power cost forecast that is currently in rates?

A. Yes. As discussed in PSE's August 1, 2023, and September 29, 2023, filings in Docket UE-230805, the 2024 power cost forecast included an update to the hydroelectric volumes used as inputs to PSE's power cost model and an update to PSE's calculation of the costs of integrating variable wind generation. PSE made these updates to better align its power cost model with more recent weather and market conditions and increasing amounts of variable renewable resources – both in the region and in PSE's portfolio.

Q. What change did PSE make to the "normal" hydroelectric volumes used in its power cost model?

A. PSE's 2024 power cost update and the current power cost forecast use monthly median hydroelectric energy volumes for each hydro project based on stream flows from the 30 years 1992 through 2021 as normal hydro inputs to the Aurora power cost model. PSE's prior methodology used monthly median volumes from the 80 years 1929 through 2008. The update to a 30-year historical period better reflects more recent hydrological conditions and aligns with other definitions of "normal" used in the Pacific Northwest region. The National Weather Service's Northwest River Forecast Center defines normal hydrological conditions based on 30 years of historical data.

Q. How did PSE change its methodology for calculating the cost of integrating variable wind generation in its 2024 power cost forecast?

A. Prior to its 2024 power cost forecast PSE used historical wind data and historical index prices to calculate wind integration cost as a product of price variance and generation forecast variance between the day-ahead and hour-ahead market timeframes. This method only recognizes the impact of variability between day-ahead and real-time markets but fails to capture costs associated with variability in wind output on daily, monthly, and annual timeframes. PSE's decision to update this wind integration calculation was driven by the growing percentage of wind in PSE's portfolio combined with increased wind generation in the region's resource supply stack, which is causing market power prices to become increasingly influenced by and inversely correlated with wind generation.

PSE's updated wind integration cost methodology relies on historical power prices and actual wind generation from 2013 to 2022 to calculate correlations between these two model inputs and to determine the standard deviation of generation for each wind resource on daily, monthly, and annual intervals. These values are then used as inputs in the Aurora model's risk sampling tool to generate 100 simulations of power price and wind output risk factors for each wind project. These risk factors are aggregated on a monthly basis to determine the adjustment to the modeled value of wind energy needed to account for variability. In Exh. BDM-12C, I summarize PSE's wind integration cost calculations for each of the wind resources included in PSE's 2025 and 2026 power cost forecast.

D. Methodology changes introduced in PSE's 2022 General Rate Case

Q. Did PSE change its forecast methodology in its 2022 General Rate Case?

A. Yes. In its 2022 General Rate Case, PSE introduced a power cost forecast methodology update to incorporate the costs and benefits of participation in the California Independent System Operator's Energy Imbalance Market ("EIM"). The power cost forecast presented in PSE's 2022 General Rate Case and all subsequent updates include EIM benefits according to a methodology developed following the settlement agreement in PSE's 2020 PCORC.[8] In that 2020 PCORC Settlement Agreement, parties agreed to "participate in a collaborative workshop on the estimation and treatment of EIM costs and benefits for rate making purposes."[9] Between June 15 and September 17, 2021, PSE hosted a series of five workshops with representatives from WUTC Staff, the Alliance for Western Energy Consumers ("AWEC"), and Public Counsel.[10] On November 22, 2021, PSE filed a report documenting the contents of the workshops, the approach developed for calculating EIM benefits, and agreement that the approach is "a reasonable method for quantifying and accounting for the net impact of EIM participation in PSE's rate year power cost forecasts." Participants further recommended that PSE use the approach in future rate proceedings, including PSE's 2022 General Rate Case.[11] Following this approach, PSE's forecast of 2025 and 2026 power costs includes most of the net benefits of EIM participation within the Aurora model results. A relatively small but incremental portion of total net benefits associated with payments for avoided greenhouse gas emissions is calculated outside of the Aurora model. The calculation of these incremental

[8] Docket UE-200980 Settlement Stipulation and Agreement.

[9] Docket UE-200980 Settlement Stipulation and Agreement, p. 6.

[10] Staff and AWEC were signatories to the 2020 PCORC Settlement Agreement. Public Counsel was not a signatory to the 2020 PCORC Settlement Agreement but did participate in the EIM collaborative workshops and did not oppose the settlement.

[11] On December 29, 2021, WUTC Staff also filed a letter documenting completion of the EIM collaborative workshops and the agreement among parties that the approach developed is "a reasonable method for quantifying and accounting for the net impact of EIM participation in PSE's rate year power cost forecasts."

benefits is based on an average of historical actual net greenhouse gas payments received by PSE and found in Exh. BDM-13.

V. MAJOR ASSUMPTIONS AND INPUTS TO PSE'S POWER COST FORECAST

1. Retail Electric Demand Forecast

Q. What forecasted electric demand did PSE use to calculate its 2025 and 2026 power costs?

A. PSE used its most current electric demand forecast for the PSE retail demand input to the Aurora model in this case.[12] The total demand forecast (net of conservation) for 2025 is 22,406,175 MWh, or 2,558 average MW. This is an increase of 105,342 MWh, or about 0.5 percent relative to forecasted 2024 demand used in PSE's 2024 power cost forecast. PSE's 2026 retail demand forecast is approximately 1.1 percent higher than forecasted 2025 demand.

2. Natural Gas Prices

Q. What natural gas prices did PSE use in its Aurora dispatch model and power cost calculations?

A. As the Commission noted in its Final Order in PSE's 2006 General Rate Case, the update for gas prices is "well-established" and should be "straightforward,

[12] PSE's full retail electric demand forecast was adjusted to remove projected demand from customers receiving service under PSE's Schedule 139 Green Direct tariff. Certain PSE power supply resources reserved to serve Green Direct customers are similarly excluded from the resource portfolio used to estimate PSE's power costs.

mechanical and non-controversial."[13] Consistent with this order and all rate cases since, PSE used a three-month average of monthly forward market prices for the forecast period from each trading day in the three-months ending November 15, 2023. PSE input these data into the Aurora dispatch model for each month of 2025 and 2026. The average 2025 gas price at the Sumas trading hub is $5.37 per million British thermal units ("MMBtu"), which is $0.35 per MMBtu or about seven percent higher than the 2024 average Sumas gas price used in PSE's 2024 power cost forecast. See Exh. BDM-5C for projected gas prices for each month in the forecast period.

3. <u>BPA Transmission Rates</u>

Q. What BPA transmission rates did PSE use in its calculation of power costs?

A. For the first nine months of 2025 PSE used current Bonneville Power Administration ("BPA") rates to calculate the costs of firm transmission capacity that PSE purchases from BPA. These rates went into effect October 1, 2023, and will remain in effect through September 30, 2025. BPA transmission rates typically change every two years and are anticipated to do so beginning October 1, 2025. PSE's power cost forecast for the last three months of 2025 and all of 2026 assumes BPA's transmission rates will increase 2.4 percent relative to current rates. This is equal to the average transmission rate increase resulting from BPA's most recent five rate updates. This assumed rate increase effective October 1, 2025, increases forecasted transmission expense $700 thousand in 2025 and

[13] *WUTC v. Puget Sound Energy* Dockets UE-060266/UG-060267, Order 08 at ¶ 104 (Jan. 5, 2007).

about $2.8 million in 2026. See Exh. BDM-14C for a detailed calculation of PSE's projected 2025 and 2026 purchased transmission expense.

4. <u>Natural Gas Resources</u>

Q. What natural gas transportation and storage resources are held by PSE for power generation?

A. PSE maintains a diverse portfolio of firm pipeline capacity and firm storage capacity to provide reliable fuel supply to its generation fleet. PSE also holds firm transportation capacity upstream of the two major pipeline interconnects at Sumas, Washington, and Stanfield, Oregon to ensure the availability and access to supply at those points and to diversify the pricing of supply. For generating facilities situated on the distribution system of Cascade Natural Gas Company PSE has reserved the necessary firm distribution service to ensure reliable deliveries of fuel acquired upstream.

PSE also contracts for firm storage service from the Jackson Prairie and Clay Basin facilities to provide reliability, flexibility, and incremental supply to the generation fleet. Storage service provides necessary reliability and flexibility to start or stop generation as needed during the gas day by providing an immediate supply of fuel or a place to store gas and avoid a pipeline imbalance. Storage also serves as an integral part of the portfolio to allow incremental deliveries in winter months because it is coupled with winter-only pipeline capacity. PSE's storage service capacity can also serve as an alternate supply source to avoid extreme pricing deviations at either of the major supply points. The natural gas pipeline and storage capacity held by PSE's electric portfolio is provided in Exh. BDM-15C, along with the calculation of projected fixed costs associated with each asset in 2025 and 2026.

Q. What pipeline tariff rates are reflected in estimated 2025 and 2026 power costs?

A. Rates in effect as of November 15, 2023, are used in PSE's projected power costs. If rate adjustments are approved by the appropriate regulatory authorities, PSE will include adjustments to the pipeline rates and related gas transportation costs when power costs are updated.

Q. How does PSE account for the value of upstream pipeline capacity and gas storage in its power cost forecast?

A. The Aurora model dispatches PSE's gas-fired generators based on the price of gas at the Sumas trading hub and Aurora fuel cost results assume all fuel is priced accordingly. To the extent PSE can access lower priced fuel supply from upstream locations, Aurora will over-estimate PSE's fuel costs. To correct for this, PSE estimates the benefits of upstream pipeline capacity outside of the Aurora model and reduces its forecasted power costs by this estimated benefit. In general, this benefit is equal to the difference between the price of gas at Sumas and the price of gas at an upstream location from which PSE has pipeline capacity, multiplied by the volume of gas that can be transported with that capacity. The benefits of upstream pipeline capacity are substantial – PSE's 2025 power cost forecast includes a $130 million reduction to account for such benefits. The projected benefit in PSE's 2024 power cost forecast was $117 million. See Exh. BDM-16C for PSE's calculation of the 2025 and 2026 power cost benefit associated with its upstream pipeline capacity. This exhibit also includes the calculated forecast period incremental costs and benefits of natural gas fuel supply that PSE had already procured for its electric portfolio as of November 15, 2023. See Exh. BDM-17C for PSE's calculation of the 2025 and 2026 power cost benefit provided by its Clay Basin storage capacity.

5. Mid-C hydroelectric contract costs

Q. What Mid-C hydroelectric contract costs are included in PSE's forecast of 2025 and 2026 power costs?

A. PSE's forecast of 2025 and 2026 power costs includes the cost of PPAs for output from five Mid-Columbia river hydroelectric facilities owned and operated by three different public utility districts ("PUD"). The projected cost of these contracts in 2025 is approximately $16 million, or seven percent higher than Mid-Columbia hydroelectric contract costs in the 2024 forecast currently included in rates. Higher total costs are primarily attributable to the extension of one of PSE's contracts for output from Douglas County PUD's Wells Hydroelectric Project included a cost increase effective October 1, 2024. This contract extension was included in forecasted 2024 power costs but only effective for three months of that year. The Prefiled Direct Testimony of Philip A. Haines, Exh. PAH-1CT provides additional information about this contract and PSE's decision to enter it.

See Exh. BDM-18C for the 2025 and 2026 cost of each of PSE's contracts for output from Mid-C hydroelectric projects.

The cost of these contracts is generally fixed according to specified contract payments or contractual formulas tied to the actual costs incurred by the PUD owner/operator of each facility. The costs included in PSE's current 2025 and 2026 power cost forecast are based on the most recent information or budgets available from the respective PUDs at the time PSE prepared its forecast. PSE would update these costs in a power cost update to the extent new or updated information is available at that time.

6. <u>Wind Generation</u>

Q. What wind generation forecasts does PSE use in its power cost forecasts?

A. PSE uses estimates of long-term average expected wind generation for each wind facility in its portfolio as inputs to the Aurora model. Forecasted wind generation for PSE's Hopkins Ridge, Wild Horse, and Lower Snake River wind facilities was developed in according to studies commissioned by PSE and carried out by Vaisala Corporation in 2016. For wind generation from facilities that PSE acquires via PPA PSE relies on forecasts provided by the owners of those facilities. Forecasted generation for the Beaver Creek wind project was provided by the developer of that project, Caithness Energy.

7. Colstrip Fuel

Q. What Colstrip fuel costs did PSE use for its power costs projections in this proceeding?

A. Colstrip units 3 and 4 fuel cost inputs to the Aurora model were determined using coal prices from the December 2019 Coal Supply Agreement ("CSA") with Westmoreland Rosebud Mining. PSE began purchasing coal according to the terms of this agreement in January 2020. The CSA includes quarterly price adjustments to account for inflation. Due to these adjustments, PSE's forecast of 2025 power costs includes a price for Colstrip fuel that is approximately 11 percent higher than Colstrip fuel prices included in PSE's 2024 power cost forecast. PSE's power cost forecast also includes the cost of diesel fuel consumed by the plant. This relatively small cost is added outside of the Aurora model and shown in Exh. BDM-19C.

8. Other Power Supply Expense (FERC account 557)

Q. What costs does PSE's forecast include for FERC account 557, other power supply costs?

A. Other power supply expenses included in PSE's 2025 and 2026 power costs are generally the cost of labor, software, subscriptions, and program fees associated with PSE's electric supply operations. These are costs chargeable to account 557 according to the Federal Regulatory Commission's Uniform System of Accounts. Unlike all of the other costs presented in my testimony these are not included in the PCA variable baseline rate and therefore would not be included in the annual power cost updates proposed in Section VI below. These "other expenses" are defined as fixed costs according to PSE's PCA mechanism. See Exh. BDM-20 for projected other power supply expenses for 2025 and 2026 with comparisons to 2024 amounts currently in rates. This projection includes labor and administrative costs associated with PSE's WRAP participation as discussed in Philip Haines's testimony, Exh. PAH-1CT.

9. Other Adjustments in PSE's Power Cost Forecast

Q. Are there any other exhibits to your testimony that support PSE's forecast of 2025 and 2026 power costs?

A. Yes. In Exh. BDM-21C I provide a calculated adjustment to remove gas-fired generator start-up costs that are not fuel costs but are included in Aurora model output from the power cost forecast. In Exh. BDM-22C I provide PSE's calculation of incremental fuel costs resulting from burning distillate fuel for testing in certain of PSE's combustion turbine generation units.

VI. ANNUAL POWER COST UPDATE

Q. What does PSE propose with respect to updating its power cost forecast in this case?

A. PSE proposes the annual power cost updates approved in its 2022 General Rate Case for calendar years 2023 and 2024 continue with respect to calendar years 2025 and 2026 and every year thereafter, with some modifications regarding the timing of filings and clarifications regarding which forecast inputs or assumptions are to be updated.

Q. Please describe the annual power cost forecast update approved in PSE's 2022 General Rate Case.

A. The revenue requirement settlement agreement in PSE's 2022 General Rate Case required PSE to update its forecast of 2023 power costs to be recovered in 2023 as part of a compliance filing at the conclusion of that case and provided a list of items that were to be updated in that compliance filing. The settlement agreement further required a compliance filing 90 days prior to the start of calendar year 2024, including an updated power cost forecast and variable PCA baseline rate to be effective in rates beginning January 1, 2024. Specifically, the 2022 General Rate Case settlement agreement states:

> PSE will update power costs for recovery in 2023 as part of its compliance filing at the conclusion of this case and include the bulleted items listed…below, as part of the power cost update.
>
> PSE is required to file a 90-day compliance filing in this proceeding to change rates effective January 1, 2024, for power costs to be recovered in 2024. In this compliance filing, PSE will update the rate recovering the PCA baseline by updating the power cost model from this filing with the cost and inputs listed below:
>
> - Costs associated with Mid-C hydro contracts;
> - Costs associated with upstream pipeline capacity;
> - Outage schedules;
> - BPA rates;
> - Load forecast (for the 2024 update);
> - Variable O&M costs;
> - Impacts to dispatch logic related to Climate Commitment Act ("CCA") compliance;
> - Hedges and physical supply contracts;
> - Natural gas prices;

- Changes to terms of current resources;
- Any new and updated resources (including transmission
- contracts);
- Nothing in this agreement limits the Settling Parties' ability to review and contest prudence in future proceedings[14]

With respect to the timing and contents of power cost update filings, the 2022 General Rate Case settlement agreement continued:

> By August 1, 2023, PSE must provide details regarding any complex changes to the PCA baseline rate including work papers demonstrating the method and effect of the changes. If there are no complex changes, PSE must provide a letter stating so. Complex changes include, but are not limited to:
>
> - Any new power resources;
> - Any new contracts (e.g., transmission);
> - Modification in any existing contract structure or form;
> - Any methodological changes to PSE's power cost calculations.
>
> a. The Settling Parties agree that by October 1, 2023, PSE must provide all other changes to the forecast.
>
> b. The compliance filing containing proposed rates to recover the new PCA baseline rate would be made by PSE with sufficient time for Commission Staff to review in order to become effective on January 1, 2024.[15]

Q. Does the annual power cost update process from the 2022 General Rate Case provide a reasonable basis for updating PSE's power costs?

A. Yes. The list of inputs and assumptions subject to update prior to rate effective periods generally includes all of the items that need to be updated to make sure power costs included in rates reflect the best information available at the time

[14] Appendix A of the Settlement Stipulation and Agreement on Revenue Requirement and all other Issues Except Tacoma LNG and PSE's Green Direct Program in consolidated Dockets UE-220066, UG-220067 & UE-210918 at ¶ 28.
[15] *Id.* at ¶ 29.

rates are established. Further, the timelines established in the settlement for final updates to the power cost forecast and variable baseline rate strike a reasonable balance between the need to provide sufficient time for review by stakeholders and approval by the Commission while also being as near to the rate effective period as practical.

Q. Is PSE proposing any modifications to the annual power cost update relative to that approved in PSE's 2022 General Rate Case?

A. Yes. PSE proposes an annual power cost update process that is overall the same as that spelled out in the settlement agreement and final order in PSE 2022 General Rate Case — but with relatively minor modifications to facilitate continuation of the process on a permanent recurring basis, clarify what is included in the power cost update and when, and provide additional time for parties to review any genuinely complex forecast changes.

Q. What modifications are necessary relative to the annual power cost update approved in PSE's 2022 General Rate Case to implement annual power cost updates on a permanent basis?

A. The annual power cost update process approved in PSE's 2022 General Rate Case was limited to updates of the effective variable power cost baseline rate in calendar years 2023 and 2024. PSE proposes that the Commission approve a similar annual update process for calendar years 2025, 2026, and every calendar year thereafter. Relative to the process outlined in the 2022 General Rate Case, the only updates needed to do this are to the dates included in the language. PSE is proposing to update power costs for recovery in 2025 as part of the compliance filing at the conclusion of this case. PSE is further proposing a 90-day compliance filing to change rates effective January 1, 2026, *and every subsequent calendar year* for power costs to be recovered in that year.

Q. Does PSE propose any modifications to the list of power cost items and forecast inputs that were identified as subject to update in the 2022 General Rate Case settlement and Final Order?

A. Yes, but only relatively minor ones. PSE proposes replacing "*Outage schedules*" with "*Planned outage schedules and forced outage rates*." This is simply for clarity. PSE's forecast methodology uses outage schedules that are planned at the time a forecast is prepared as inputs to the Aurora model. For forced outages, PSE uses a four-year average of actual historical forced outage rates. PSE further proposes revising "*Load forecast (for the 2024 update)*" to say "*PSE's retail electric demand forecast*." Finally, PSE proposes removing "*Impacts to dispatch logic related to Climate Commitment Act ("CCA") compliance*" and adding "*The price of emissions allowances for compliance with the Climate Commitment Act*." This replaces an undefined methodology change with a simple update to the price used as an input to a previously-defined methodology.

The methodology PSE proposes to calculate the impact to power costs of including the CCA in its dispatch decisions is described in Section IV above. All of the items on this list, including the addition of new resources, are straight-forward and well documented inputs or assumptions in PSE's power cost forecast.

While the impact to forecasted power costs associated with updates to these assumptions and inputs may at times be significant, the process by which they are included in PSE's power cost forecast is not complex and should not be controversial.

Q. What modifications to the timeline for annual power cost updates does PSE propose?

A. The 2022 General Rate Case annual update process required PSE to provide details regarding any "complex changes" to the forecast by August 1, 2023, or about five months before the effective date of the 2024 rate update. PSE proposes including a preliminary power cost forecast and the details and effect of any proposed forecast methodology changes by April 30 of the year prior to the year rates will be in effect. This revised timeline provides an additional three months for parties to review any proposed methodology changes. This proposed timeline aligns with the date by which PSE currently files its annual PCA filing, which includes a review of actual power cost results from the prior year. PSE would then still file its final power cost forecast and variable baseline rate 90 days prior to the start of the rate effective date, but that update would include changes only to the items specifically included in the bulleted list of inputs and assumptions above (with PSE's proposed modifications).

Q. When will parties and the Commission review the prudence of any new resources included in PSE's annual power cost update?

A. The 2022 General Rate Case power cost update process calls for new resources included in the power cost forecast to undergo a prudency review as part of PSE's annual PCA compliance filing.[16] This timing is reasonable as it will often be the first available opportunity for PSE to present prudence details regarding new resource acquisitions. However, in the event PSE files a general rate case or PCORC before its annual PCA compliance filing, PSE would seek a prudence determination for any new resources in that general rate case or PCORC proceeding. In other words, any new resources included in PSE's power cost forecast and baseline rate will undergo a prudency review at the earliest opportunity, whether that is PSE's annual PCA compliance filing, a general rate case, or a PCORC filing.

Q. Is PSE's ability to file PCORCs still necessary if the Commission approves an annual power cost update?

A. Yes. PSE's proposal for an annual power cost update would address the need to align the variable portion of the baseline rate more closely with the variable power costs PSE actually expects to incur. It would not address the need to include in rates accurate fixed costs associated with the resources PSE owns and operates. Upcoming resource additions driven by CETA and resource adequacy requirements could take the form of PPAs, which would flow through power costs

[16] *Id.* at ¶ 30.

and the variable portion of the baseline rate, or physical assets, which would have capital and operations and maintenance costs that require recovery through the fixed portion of the baseline rate. PCORCs will continue to be needed for timely updates to PSE's fixed production costs and to minimize the amount of time costs of new resources spend in deferral.

Q. Would PSE continue to update its power cost forecast and variable baseline rate in general rate case or PCORC proceedings if annual power cost updates are implemented on an ongoing basis?

A. No. The annual power cost update process described above would obviate and replace the need to updated variable power costs in general rate case or PCORC proceedings. Variable power costs would no longer need to be a component of the general rates that PSE updates in such proceedings. In this regard, variable power costs would be treated similarly to natural gas supply costs for PSE's gas utility – these are updated only in annual Purchased Gas Adjustment filings and not included in general rate updates.

VII. CONCLUSION

Q. What is PSE request regarding power costs in this case?

A. PSE respectfully requests that the Commission approve the power cost forecast methodology presented herein as appropriate for calculating 2025 power costs and establishing the PCA variable baseline rate that will go into effect at the conclusion of this proceeding. PSE requests that the Commission order and authorize a compliance filing at this end of this proceeding that includes an update to inputs and assumptions used in PSE's 2025 power cost forecast with the most recent information available at that time. Further, PSE requests that the Commission authorize annual power cost forecast and PCA variable baseline rate updates to be effective in 2026 and each calendar year thereafter according to the schedule and process outlined in Section VI above.

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.