EXH. BDM-1CT
DOCKET UE-24___
2023 PCA COMPLIANCE FILING
WITNESS: BRENNAN D. MUELLER

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PUGET SOUND ENERGY For Approval of its 2023 Power Cost Adjustment Mechanism Report	Docket UE-24____

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

BRENNAN D. MUELLER

ON BEHALF OF PUGET SOUND ENERGY

SHADED INFORMATION IS DESIGNATED AS CONFIDENTIAL PER WAC 480-07-160

REDACTED VERSION

APRIL 30, 2024

PUGET SOUND ENERGY

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) 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 of 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, I have. It is Exh. BDM-2.

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 background information regarding PSE's Power Cost Adjustment ("PCA") mechanism. I then describe PSE's resource portfolio compared to the portfolio assumptions included in rates for the 2023 PCA Period. Next, I explain the drivers of PSE's 2023 power cost over-recovery and provide analysis of the variances between actual power costs and power costs included in the PCA variable baseline rate for 2023. I then discuss impacts of Washington's Climate Commitment Act ("CCA") cap-and-invest program on PSE's electric operations and power costs since commencement of the program in January 2023. The final section of my testimony describes PSE's actual power cost results through March of this year and PSE's projection of power costs for the remainder of 2024.

II. BACKGROUND REGARDING THE PCA MECHANISM

Q. Why does PSE have a PCA mechanism?

A. Volatility in wholesale energy markets coupled with variations in power supply and retail demand lead to differences between the actual cost of PSE's power supply portfolio and the costs recovered in customer rates. The PCA mechanism seeks to balance the risk of such power cost differences between customers and PSE by providing a method to share costs and benefits if power costs deviate significantly from those embedded in rates. The PCA mechanism originally took effect on July 1, 2002, following a settlement agreement that originated in PSE's 2001 general rate case. As part of PSE's 2013 power cost only rate case, Docket UE-130617, PSE and parties to that proceeding initiated a collaborative process to address issues relevant to the PCA mechanism. That process resulted in a multiparty settlement that changed certain elements of the PCA. The multiparty settlement was approved by the Commission and changes became effective on January 1, 2017.

Q. How does the PCA mechanism work?

A. The PCA mechanism accounts for differences in PSE's actual power costs relative to the power cost baseline recovered in rates. The costs or benefits of such variances are shared between PSE and customers according to three graduated levels of power cost variance, or bands. 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 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 (under-recoveries) or benefits (over-recoveries).

The customers' share of power cost variances is accounted for each year and deferred until the cumulative balance in the deferral account triggers a refund or allows a surcharge. PSE consistently under-recovered power costs between 2019 and 2022 and a customer surcharge is currently in place to recover the customers' share of those accumulated imbalances. The Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, contains further information regarding accounting for the cumulative balance.

Q. What was the basis for power costs included in rates during calendar year 2023?

A. The PCA baseline rate approved in PSE's 2020 power cost only rate case, Docket UE-200980 ("2020 PCORC") went into effect July 1, 2021, and remained the effective rate through January 10, 2023. A new baseline rate established in PSE's 2022 general rate case[1] ("GRC") took effect beginning January 11, 2023. This new baseline rate was established based on a forecast of PSE's 2023 power costs updated according to the terms of the 2022 GRC Settlement Agreement[2] and approved by the Commission on January 10, 2023.[3]

III. 2023 PCA PERIOD POWER COSTS

<u>A. PSE's 2023 PCA Period Power Supply Resources</u>

Q. Were there changes to PSE's electric supply resources during the 2023 PCA Period relative to those included in the baseline rate?

A. Yes. As noted above, the baseline rate in effect for the first ten days of 2023 reflected the power portfolio from PSE's 2020 PCORC. PSE's resource portfolio changed significantly between the time rates were established in the 2020 PCORC (June 17, 2021) and the beginning of 2023. However, for most of 2023 the baseline rate reflected PSE's power portfolio at the time PSE prepared the power cost forecast used to establish rates in its 2022 GRC.

[1] Docket UE-220066 & UG-220067, *et al*.

[2] Docket UE-220066 & UG-220067, *et al.*, Final Order 24/10, Appendix A "Revenue Requirement Settlement," at ¶ 29 (Dec. 22, 2023).

[3] *See* Docket UE-220066, UG-220067, *et al.,* Notice issued Jan. 10, 2023.

PSE made only one addition to its actual resource portfolio during 2023 that was not reflected in rates from the 2022 GRC, a power purchase agreement ("PPA") for output from a co-generation facility located within PSE's service territory ("HF Sinclair PPA"). PSE executed the HF Sinclair PPA on June 1, 2023, and deliveries began July 1, 2023. The contract provides PSE with approximately 70 MW of energy and capacity that is surplus to the requirements of the HF Sinclair refinery in Anacortes, WA. PSE presented details regarding its decision to enter the HF Sinclair PPA in its 2024 GRC in the prefiled direct testimony and supporting exhibits of Philip A. Haines, and such testimony and supporting exhibits are provided in this filing as Exh. BDM-3C.

The actual source of energy supplies used to serve PSE's retail demand in 2023 also varied from the amount projected in rates due to changes in actual demand, availability of variable resources (wind and hydroelectric), and differences in the market prices of natural gas and electricity, which drive changes in PSE's utilization of its natural gas fueled generators.

Q. Please summarize PSE's actual electric energy supply during the 2023 PCA Period compared to the amounts included in rates.

A. Table 1 below provides a comparison of the generated and purchased energy volumes used to serve demand during 2023 relative to the resource volumes included in rates.

Table 1: Actual 2023 Energy Supply Volumes versus Volumes Included in Rates (MWh)

	Actual	Rates	Variance
Coal-fueled generation (Colstrip)	2,673,671	2,715,295	(41,624)
Natural gas-fueled generation	9,954,456	8,944,994	1,009,463
Long-term contracts (PPAs)	8,361,913	8,205,709	156,204
Hydroelectric (PSE-owned + Mid-Columbia contracts)	3,995,955	5,000,082	(1,004,127)
Wind (PSE-owned)	1,565,462	1,943,981	(378,519)
Net market purchases & sales	(4,600,894)	(5,320,288)	719,394
Total supply (load, before system losses)	21,950,563	21,489,773	460,790

B. PSE's 2023 PCA Period Power Costs

Q. How did PSE's actual power costs for the 2023 PCA Period compare to power costs recovered through rates?

A. During the 2023 PCA Period PSE recovered $947.8 million of power costs through the PCA variable baseline rate and incurred actual allowable power costs of $896.7 million. This $51.1 million over-recovery is outside of the $17 million dead band, so PSE will share a portion of these benefits with customers according to the PCA sharing bands. The customer share of 2023 PCA Period over-recovery before interest is $24.9 million.

Q. Why do actual power costs differ from those set in rates?

A. The actual cost of power delivered to PSE's system will always differ from the forecasted costs included in rates because actual power costs reflect the realized outcome of multiple power cost variables, many of which are weather dependent or otherwise difficult to predict with precision. These variables include:

i. customer demand (load),
ii. the supply of hydroelectric energy,
iii. output from variable energy resources such as wind and solar,
iv. unplanned generation outages and the timing of planned outages,
v. transmission and natural gas transportation constraints, and
vi. market energy prices, which are themselves influenced by the variables listed above.

Finally, while power costs included in rates are estimated "as closely as possible to costs that are reasonably expected to be actually incurred,"[4] estimates are limited by regulatory normalizing assumptions. Specifically, rates established in the 2022 GRC normalized power cost variables by utilizing:

i. a weather normalized retail demand forecast,
ii. hydroelectric generation based on 30 years of historical streamflow data,
iii. forecasts of long-term average wind generation,
iv. historical average generator forced outage rates,
v. gas prices equal to a historical three-month average of forward market prices, and
ii. model-generated market electricity prices, which relied upon normalized assumptions for demand, variable resource output, and generator availability throughout the Western Interconnect.

[4] *Wash. Utils. & Transp. Comm'n. v. Puget Sound Energy, Inc.,* Docket UE-040640, *et al.,* Order 06 at ¶ 108 (Feb. 18, 2005).

Q. What caused the difference between PSE's actual power costs and power costs recovered in rates during the 2023 PCA Period?

A. During the 2023 PCA Period, PSE's total actual allowable power costs were $51.1 million lower than power costs recovered in rates. This over-recovery was the result of actual allowable costs that were $17.7 million lower than costs included in rates and baseline rate revenue that was $33.4 million higher than revenue assumed in rates. Actual costs were lower than those included in rates primarily due to higher revenue from wholesale sales of surplus generation combined with lower natural gas fuel costs, both the result of actual market energy prices that differed from those assumed in rates. Higher baseline rate revenue was due to actual delivered load that was 3.5 percent higher than the delivered load forecast used to establish rates.

Q. Please summarize PSE's actual 2023 power cost variance relative to the costs included in rates and the 2023 PCA over-recovery.

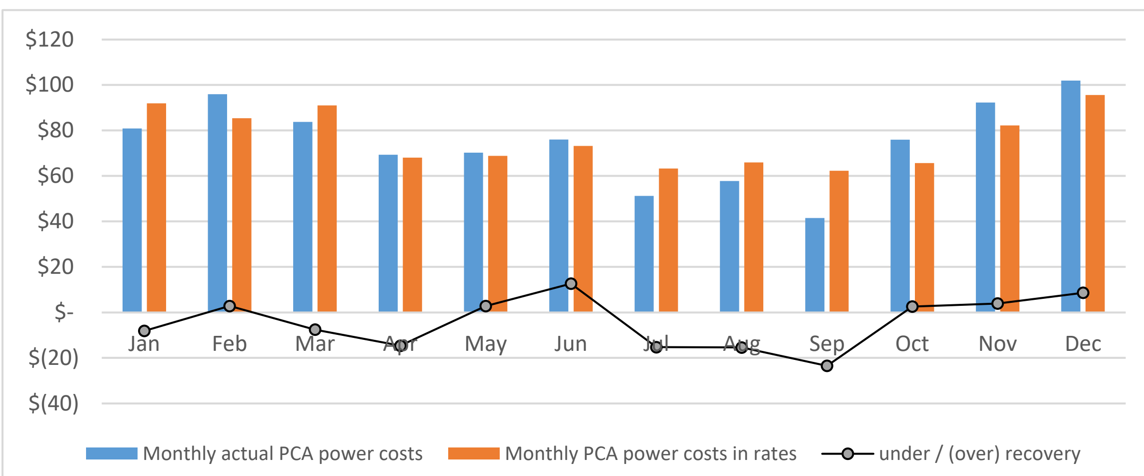
A. Table 2 below provides a comparison of 2023 actual power costs relative to those included in rates by resource type and the impact of load variance on baseline rate revenue. These variances sum to the $51.1 million total over-recovery and are discussed in more detail below.

Table 2. Actual 2023 PCA Costs and Revenue versus Amounts in Rates ($ in millions)

	Actual	Rates	Variance
Coal fuel	$60.6	$65.2	($4.5)
Natural gas fuel and transportation	$349.1	$368.0	($18.9)
Long-term contract purchases	$722.7	$705.3	$17.4
Net market purchases & sales	($403.0)	($364.7)	($38.2)
Transmission	$162.6	$134.9	$27.7
Other PCA items	$4.7	$5.8	($1.2)
Total PCA variable cost	$896.7	$914.4	($17.7)
PCA revenue from delivered load	($947.8)	($914.4)	($33.4)
2023 PCA over-recovery	($51.1)	($0.0)	($51.1)

Figure 1 below shows monthly actual 2023 power costs compared to power costs in rates as well as the monthly actual PCA under or (over) recovery.

Figure 1: Monthly Actual 2023 PCA Costs and Revenue versus Amounts in Rates ($ in millions)



C. 2023 PCA Variance Discussion

Market prices

Q. How did actual 2023 market energy prices compare to the prices assumed in rates?

A. Actual market prices for both power and natural gas during January 2023 were significantly higher than prices assumed in rates, but for the remainder of the year gas prices were consistently lower than assumed in rates while power prices were only slightly lower than forecast. Market heat rates, the relative price of electricity versus natural gas, were therefore consistently higher than the forecast in rates. These higher market heat rates made gas fueled generators more economic to run—even after consideration of additional costs associated with the CCA cap-and-invest program. Natural gas generation volumes and the effects of the CCA on these resources are both discussed further below. Figure 2 and Figure 3 compare actual 2023 market energy prices to those assumed in rates for natural gas and electricity, respectively.

Figure 2: 2023 actual Sumas gas prices versus Sumas gas prices in rates ($/MMBtu)

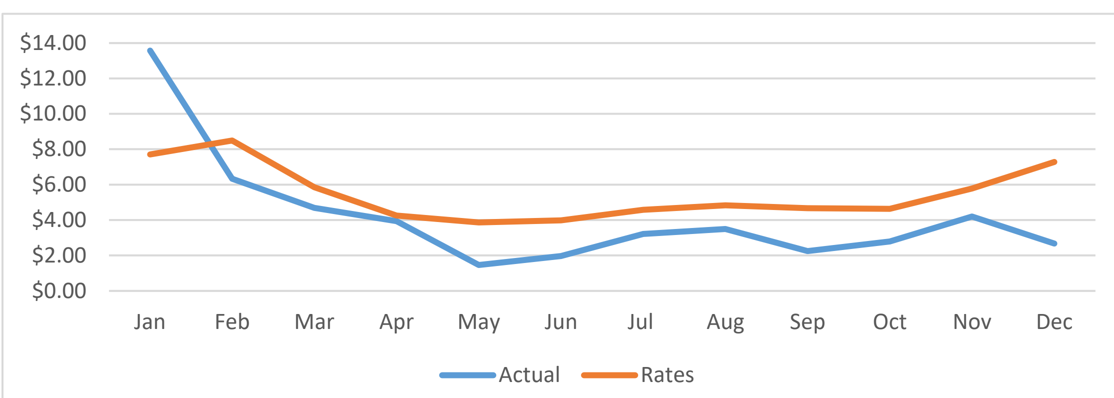
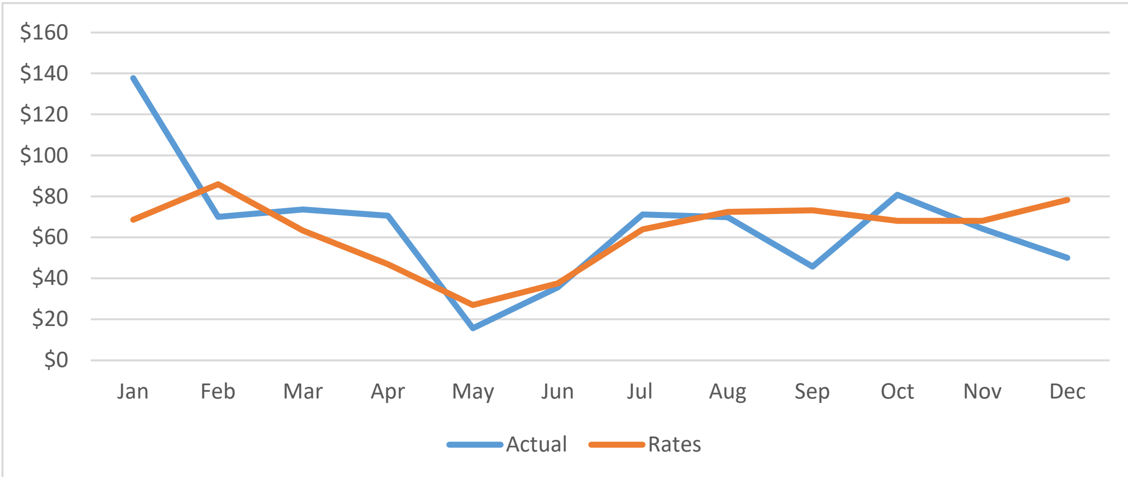


Figure 3. 2023 Actual Mid-Columbia Power Prices versus Power Prices in Rates ($/MWh)



Retail demand

Q. How did variances in actual retail demand relative to the forecast in rates impact PSE's 2023 PCA Period over-recovery?

A. Actual PSE demand in 2023 was approximately 3.5 percent higher than the demand forecasts included in rates during 2023. Higher actual demand had two different, partially off-setting impacts on power cost recovery in 2023. First, higher demand increases PSE's actual power costs because it increases the amount of energy that must be purchased in the wholesale market and/or decreases the amount of surplus energy that can be sold in the wholesale market. Second, higher demand increases retail sales, which increases revenue collected via the power cost baseline rate. During 2023, higher demand increased power costs approximately $29 million but increased PCA revenue by $33 million. The net impact of higher demand was therefore an approximately $4 million contribution to PSE's 2023 power cost over-recovery.

Market purchases and sales

Q. How did market purchases and sales during the 2023 PCA Period compare to amounts in rates?

A. In 2023 PSE's actual electric market sales and purchases resulted in a $38.2 million reduction to power costs compared to the amount in rates. Actual spot market purchase costs were $52.4 million higher than in rates, but more than offset by market sales revenue and benefits from financial hedge contracts that were $90.6 million higher than in rates. Actual market purchases and sales were 64.4 and 5.9 percent above volumes forecasted in rates respectively, resulting in fewer net sales than assumed in rates. The forecast in rates for 2023 estimated PSE would be a net seller of 5.3 million MWh, while actual net sales were 4.6 million MWh.

Lower actual net market sales volume for the year was the result of higher retail demand and lower generation from Colstrip, wind resources, and PSE's Mid-Columbia ("Mid-C") hydroelectric resources relative to the forecast in rates. While the cost of actual purchases was 50.6 percent, or $55.2 million, above the cost included in rates, the average cost of actual market purchases in 2023 was only $56.47 per MWh, compared to $61.65 per MWh included in rates. Partially offsetting the increase in power costs from higher purchases, sales revenue was 7.7 percent higher or $35.5 million more than forecasted in rates. The actual volume of market sales in 2023 was 3.3 percent above the forecast in rates for 2023 and the average price of actual market sales was $68.17 per MWh compared to $65.43 per MWh included in rates. The $19.7 million net increase relative to rates from spot market purchases and sales was more than offset by benefits from financial hedge contracts that were $57.9 million higher than forecasted in rates.

Colstrip

Q. How did actual coal fuel costs compare to costs in rates during the 2023 PCA Period?

A. Actual fuel cost for PSE's Colstrip Units 3&4 was $4.5 million lower than the cost included in rates for 2023. This cost variance was primarily the result of lower actual generation than was forecasted in rates. Actual Colstrip output in 2023 was 1.5 percent, or 41,624 MWh, lower than generation included in rates.

Natural gas generation and transportation

Q. Why were actual 2023 natural gas fuel and transportation costs lower than the costs included in rates?

A. Total actual natural gas fuel and transportation costs during 2023 were 5.1 percent, or $18.9 million lower than costs included in rates even as generation from gas-fueled resources was 11.3 percent higher than forecasted in rates. These lower costs were the result of lower gas prices. Lower natural gas prices led to an average cost of fuel for these resources that was lower than assumed in rates. Actual per-unit fuel cost for PSE's gas-fired resources in 2023 was $36.57 per MWh compared to $49.13 per MWh included in rates. Significantly lower fuel costs combined with relatively little change in power prices (effectively the market heat rate) made it more economic to run the facilities more often. Figure 4 and Figure 5 below show PSE's actual natural gas-fired generation and market heat rates relative to forecasts included in rates for 2023.

Figure 4: 2023 Actual Gas Generation versus Gas Generation in Rates (Mwh)

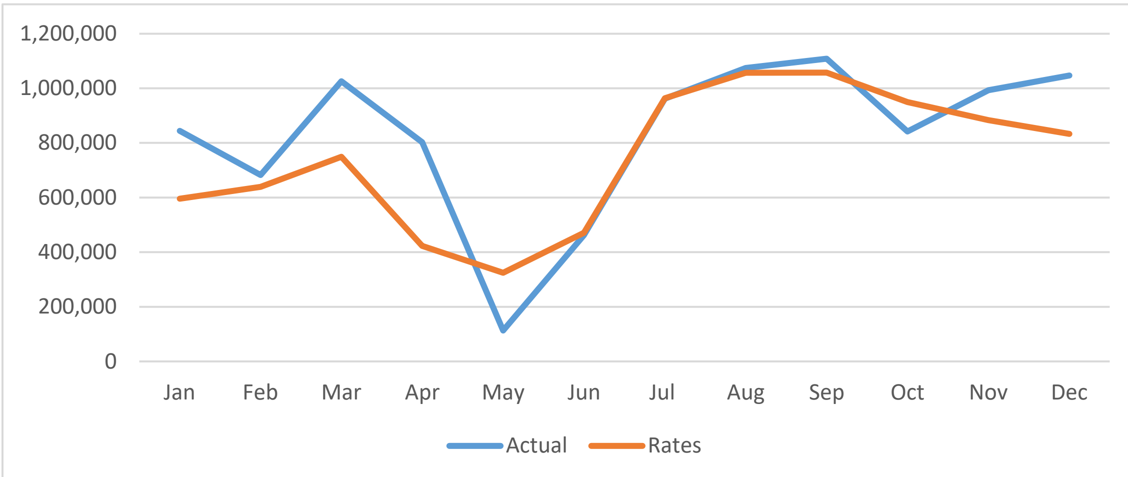
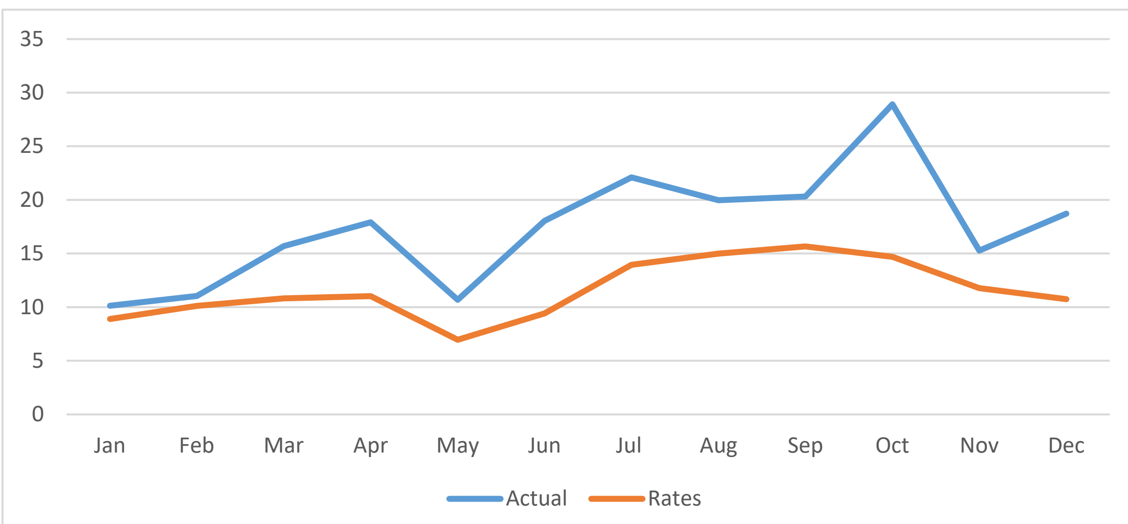


Figure 5: 2023 Actual Flat Market Heat Rates versus Flat Market Heat Rates Assumed in Rates (Mmbtu/Mwh)



Long-term contracts (Power Purchase Agreements)

Q. How did PSE's PPAs affect power costs during the 2023 PCA Period?

A. In 2023 PSE received 8,361,913 MWh from PPAs (excluding Mid-C hydroelectric PPAs), which was a 1.9 percent increase over the volume included in rates during 2023 (8,205,709 MWh). The combined actual cost of these contracts was $548.3 million, or 6.5 percent, higher than the cost included in rates. The average price for the long-term contracts included in rates was $62.74 per MWh, while the actual price in 2023 was $65.58 per MWh, or 4.5 percent higher than assumed in rates. This higher unit cost was in part due to the first ten days of January, during which several relatively new PPAs were not reflected in rates, and in part due to the addition of the HF Sinclair PPA. The HF Sinclair PPA, which was not included in rates during 2023, contributed an estimated $7.5 million to higher power costs ($28.4 million actual 2023 cost less a $20.9 million estimated benefit in the form of reduced market purchases).

Q. Why were Mid-C hydroelectric contract costs lower than the amounts included in rates?

A. The actual cost of PSE's Mid-C hydroelectric contracts in 2023 was approximately $16.1 million lower than the amount included in rates. The variance in the cost of PSE's Mid-C hydroelectric contracts relative to the cost in rates was the result of lower actual costs billed by Chelan County Public Utility

District ("Chelan PUD")[5] ($8.7 million) as well as lower variable charges resulting from lower hydroelectric generation. Actual output from Mid-C hydroelectric contracts was 19.0 percent, or 772,296 MWh, below generation included in rates for 2023. Lower generation reduced variable payments according to contracts with Chelan PUD and Grant County Public Utility District by approximately $7.4 million relative to forecasted payments assuming normal hydroelectric generation. However, lower hydroelectric generation relative to the forecast in rates increased the net cost of PSE's market purchases and sales in 2023 by approximately $58.6 million (based on actual monthly flat Mid-C power prices).

PSE wind and hydroelectric

Q. How did output from PSE-owned wind and hydroelectric resources affect power costs in 2023?

A. There are no fuel or purchased power costs associated with PSE-owned wind and hydroelectric assets, so there are no direct cost variances associated with these resources in 2023 actual PCA results relative to costs in rates. Instead, variances in the output of PSE's wind and hydroelectric resources drive changes in PSE's market purchases and sales relative to the forecasts in rates. Each MWh that is not generated by a wind or hydroelectric resource requires PSE to purchase (or not sell) one MWh in the market. Actual output from PSE's wind resources in 2023 was 19.5 percent, or 378,519 MWh, below wind generation included in rates for

[5] Under its contract with Chelan PUD for 25 percent of the output from the Rocky Reach and Rock Island hydroelectric projects, PSE pays a portion of the actual costs Chelan PUD incurs to run the projects.

2023. This generation variance relative to rates increased the net cost of PSE's actual 2023 market purchases and sales by approximately $23.4 million (based on actual monthly flat Mid-C power prices).

Actual output from PSE-owned hydroelectric resources in 2023 was 24.9 percent, or 231,831 MWh lower than generation included in rates for 2023. This generation variance relative to rates increased the net cost of PSE's actual 2023 market purchases and sales approximately $14.1 million (based on monthly actual flat Mid-C power prices).

Transmission

Q. Why did actual transmission expense vary from the amount in rates during the 2023 PCA Period?

A. During the 2023 PCA Period, the total net cost of purchased transmission was $27.7 million higher than the costs included in rates. These higher costs were the result of transmission contract costs that were $25.0 million higher than the amount in rates and revenue from transmission reassignments (short-term sales of surplus transmission capacity) that was $2.7 million lower than the amount in rates. Transmission contract costs in 2023 were higher than the amount in rates primarily because PSE's forecast used to establish rates failed to account for the cost of BPA loss returns. This error was corrected and explained in PSE's 2024 Power Cost Update filing that established the PCA baseline rate for calendar year 2024.[6]

[6] *See* Docket UE-230805.

IV. CCA CAP-AND-INVEST PROGRAM IMPACT ON RESOURCE UTILIZATION, PSE EMISSIONS, AND POWER COSTS

Q. Did the CCA cap-and-invest program impact PSE's 2023 power cost results?

A. Yes. The CCA cap-and-invest program, which took effect on January 1, 2023, requires PSE to obtain an emissions allowance for each metric ton of CO_2 emitted from its power plants located within the state of Washington as well as the emissions associated with electricity imported by PSE into Washington. In order to mitigate the cost impacts of this program, the Department of Ecology ("Ecology") allocates no-cost allowances for emissions associated with electricity used by PSE to serve retail demand. PSE therefore expects allowances will need to be purchased for emissions associated with its secondary market sales. This means that generation can only be economically dispatched for secondary sales if the revenue from such sales is sufficient to cover both traditional variable costs (primarily fuel) and the anticipated cost of emissions allowances. Consideration of this additional cost in resource dispatch decisions reduced 2023 output, emissions, and fuel costs associated with PSE's gas-fueled generators relative to how they would have been dispatched absent the cap-and-invest program. However, this change in resource dispatch also reduced the volume of PSE's secondary market sales and the revenue from such sales that otherwise would have reduced actual 2023 variable power costs.

Q. Has PSE quantified the impact of the CCA cap-and-invest program on 2023 power costs?

A. Yes. PSE estimates that consideration of emissions allowance costs in its resource dispatch decisions increased actual 2023 power costs approximately $2.8 million. This increase is the net result of an estimated $10.8 million reduction in secondary sales revenue offset by $8.0 million in avoided fuel costs. Because these indirect cap-and-invest program costs were not reflected in the 2023 PCA baseline rate they contributed an approximately $2.8 million negative variance in PSE's 2023 PCA results (caused the 2023 over-recovery to be less than it otherwise would have been).

Q. Why did consideration of emissions allowance costs in PSE's resource dispatch decisions increase 2023 power costs?

A. Only the indirect costs of the CCA cap-and-invest program, or the net impact of the reduction to secondary sales revenue and reduction to fuel costs described above, is included in PSE's actual 2023 PCA results. Direct emissions allowance costs are not currently included in the PCA definition of variable power costs. Therefore, while consideration of emissions allowance costs in PSE's resource dispatch decisions did reduce *total* expected costs, the savings associated with avoided emissions allowance purchases is not included in 2023 PCA results. PSE's consideration of emissions allowance costs in resource dispatch decisions reduced 2023 CO_2 emissions by approximately 84,000 metric tons and avoided approximately $4.8 million of emissions allowance costs (based on daily secondary market allowance prices). Expected reductions to the direct cost of emissions allowance purchases therefore more than offset the estimated $2.8 million increase to PCA power costs.

Q. How did PSE estimate the indirect power cost impacts from considering emissions allowance costs in its dispatch decisions?

A. The actual indirect costs of including emissions allowance costs in dispatch decisions are embedded in actual 2023 secondary sales revenue and natural gas fuel costs. Such indirect costs therefore must be estimated using a counterfactual model to determine what PSE's power costs would have been had plants been dispatched without considering the cost of emissions allowances. Please see Exh. BDM-4 for a summary of estimated indirect power cost impacts, avoided emissions, and avoided emissions allowance costs from January 2023 through March 2024.

Q. Has PSE quantified its emissions obligation associated with secondary sales of emitting generation during 2023?

A. Yes. PSE estimates that approximately [redacted] MWh of generation from its natural gas-fueled resources were used to supply wholesale market sales in 2023. This translates to an emissions obligation of approximately [redacted] allowances, for which PSE does not anticipate receiving no-cost allowances. Exhibit BDM-5C includes PSE's calculation of this emissions obligation and the associated costs which are discussed below. These estimates are based on PSE's expectation of how Ecology will implement its no-cost allowance adjustment process and there is still some uncertainty as to how exactly that process will be implemented. The actual emissions obligation associated with PSE's sales of surplus generation from its gas-fueled generators will depend on how Ecology ultimately determines which resources were used to serve PSE retail demand. PSE anticipates results of the no-cost allowance adjustment process for 2023 will be available in October 2024.

Q. Is the revenue that PSE received from wholesale market sales of emitting resource generation sufficient to compensate for the expected cost of associated emissions allowances?

A. Yes. By considering the cost of emissions allowances in its resource dispatch decisions PSE attempts to ensure that emitting generation is only sold into the wholesale market if the price received for such sales is at least high enough to compensate for the cost of fuel and the cost of emissions allowances. PSE received approximately $[redacted] in revenue for the estimated [redacted] MWh of emitting generation sold during 2023. The fuel cost associated with generating these [redacted] MWh was only about $[redacted]. The difference between the revenue received and the cost of generation [redacted] is a reduction to PCA power costs included in PSE's actual 2023 results. However, this benefit to PCA power costs over-states the full net benefit from wholesale sales of emitting generation because it does not include the cost of allowances [redacted] to cover the associated emissions. Based on secondary market allowance prices at the time PSE made its decisions to sell surplus emitting generation, this cost was approximately $[redacted] considerably less than the $[redacted] of net revenue collected to reduce PCA power costs. [redacted].

Q. Will revenue collected from wholesale sales of surplus emitting generation always be enough to cover the cost of associated emissions allowances?

A. No. While inclusion of allowance costs in PSE's resource dispatch decisions limits uneconomic sales of surplus emitting generation, PSE cannot ensure that the cost of emissions allowances for wholesale sales will always be fully offset by the revenue received from such sales. This is because not all of PSE's wholesale market sales are based on the economics of a particular transaction.

Many of PSE's wholesale sales are the result of balancing short-term changes in supply and demand or otherwise ensuring reliable operations. For example, PSE may have to run a gas-fueled generator for the sole purpose of providing flexible reserve capability that can follow unpredictable fluctuations in demand or wind output. If all of PSE's current retail demand is already being supplied with other resources, then the output from the generator providing reserves will be surplus to

[7] [redacted]

current needs and will be sold in the wholesale market – often at a price that does not even fully recover fuel costs.

Q. Is the estimated allowance obligation associated with wholesale sales of emitting generation all of the emissions allowances PSE needs to purchase?

A. No. PSE also incurs emissions obligations associated with imports of electricity from outside Washington state that may not be fully covered by PSE's allocation of no-cost allowances. PSE currently estimates this additional obligation for 2023 to be approximately [redacted] metric tons. PSE's actual net obligation associated with imported electricity will ultimately depend on how Ecology actually implements its no-cost allowance allocation adjustment process in October 2024.

V. 2024 POWER COST PROJECTION AND EXPECTED PCA UNDER-RECOVERY

Q. What are PSE's projections of 2024 power costs and PCA recovery results?

A. As of the end of the first quarter of 2024, PSE projects full year power costs to be $140.0 million higher than those included in the 2024 variable baseline rate. These higher costs are partially offset by higher revenue resulting from higher retail load such that the projected 2024 PCA under-recovery is $127.5 million. After application of the PCA sharing bands, the customers' share of this projected under-recovery is $90.3 million (before interest). Exhibit BDM-6C includes PSE's actual (three months) and forecasted (nine months) PCA power costs for calendar year 2024 and a comparison to the power costs included in the effective PCA variable baseline rate for 2024. Exhibit BDM-7C is PSE's PCA Schedule B calculation applied to the 2024 actual-plus-forecast power cost results. It shows the calculation of projected under-recovery and application of the PCA sharing bands to determine the projected $90.3 million customer share of the under-recovery.

Q. Why is PSE discussing 2024 projections in its 2023 PCA filing?

A. The PCA settlement allows a customer surcharge to be initiated when PSE projects that for any upcoming 12-month period the PCA deferral balance will exceed $20 million. PSE's projected increase to the 2024 deferral balance of more than $90 million is well in excess of this amount. As discussed in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, PSE is proposing to effectively initiate this surcharge by keeping in place an existing surcharge: rather than allowing the existing surcharge to expire, replacing it with a credit for the 2023 over-recovery and then replacing that credit later with a surcharge for the projected 2024 under-recovery.

Q. What is driving PSE's projected 2024 PCA under-recovery?

A. PSE's projected 2024 PCA under-recovery is primarily the result of a cold weather event in January 2024 that drove retail electric demand to record highs and coincided with extremely high market power prices and low output from PSE's wind generation resources. Please see the Prefiled Direct Testimony of Philip A. Haines, Exh. PAH-1CT, for additional discussion of the January cold weather event. PSE's actual under-recovery year-to-date through March 2024 is

$110.7 million (out of the projected $127.5 million 2024 total), with $93.0 million of that attributable to January results. The accumulated customer share of PSE's year-to-date under-recovery is $75.2 million (before interest). The projected under-recovery for the remaining nine months of 2024 ($16.5 million) and associated customer share ($15.1 million) is due primarily to the result of projected unfavorable hydroelectric output and changes to market power and natural gas prices relative to assumptions included in the 2024 baseline rate. Exhibit BDM-8C provides the monthly detail of PSE's actual-plus-projected 2024 power costs by line item and energy supply volumes by resource.

Q. How did PSE calculate its forecast of power costs for the last nine months of 2024?

A. PSE prepared its balance-of-year 2024 power cost forecast using the same model and methodologies that were used in the forecast that established the variable baseline rate in effect for 2024, but for three exceptions:

1. Generation from hydroelectric plants has been reduced to reflect below normal hydrologic conditions that the Pacific Northwest is currently experiencing and are projected to continue through at least September 2024. This update to hydroelectric volumes differs from the long-term normal (30 year median) hydroelectric volumes assumed in PSE's 2024 baseline rate forecast.

2. PSE's current forecast of 2024 power costs only uses output from the hourly Aurora model run. It does not include subsequent sub-hourly model runs that were used to estimate sub-hourly balancing costs and offsetting energy imbalance market benefits in PSE's 2024 baseline rate forecast. Removal of the sub-hourly models runs, which are time and data intensive, is not expected to have a material impact on PSE's projection of 2024 power costs or the resulting PCA under-recovery. Omission of the sub-hourly modeling removes both sub-hourly balancing costs and the energy imbalance market benefits that reduce those costs. PSE's current 2024 power cost forecast does still include approximately $2 million of estimated direct EIM benefits associated with payments for greenhouse gas emissions (or avoided emissions) for energy exported to California.

3. PSE's current forecast employs a methodology for estimating the indirect power cost impacts of including CCA emissions allowance costs in its dispatch decisions. This methodology and the associated estimated power cost impacts were rejected by the Commission for inclusion in PSE's 2024 baseline rate forecast,[8] but PSE continues to believe this methodology provides a reasonable estimate of the indirect power cost impacts of the CCA given how PSE is incorporating emissions allowance costs in its actual dispatch decisions. However, with updated market prices and resource volumes, PSE's methodology projects no power cost impact from including

[8] *See* Docket UE-230805 *et al*., Order 01, at ¶ 43 (Dec. 22, 2023).

emissions allowance costs in dispatch decisions for the remainder of 2024. Put differently, PSE's decision to include the CCA impacts methodology in its current forecast model has no effect on PSE's current projection of 2024 power costs.

Q. Did the CCA cap-and-invest program impact PSE's 2024 year-to-date power cost results?

A. Yes. PSE continues to include the cost of emissions allowances in its actual resource dispatch decisions. PSE estimates that consideration of these additional dispatch costs increased actual year-to-date 2024 power costs approximately $2.8 million while reducing expected allowance purchase costs approximately $3.1 million. These estimates are summarized along with the 2023 estimates described above in Exh. BDM-4.

Q. How do updated hydroelectric volumes effect PSE's current forecast of 2024 power costs?

A. PSE's current forecast of 2024 power costs uses hydroelectric volumes for April through September (remaining current water year) based on water supply forecasts from the Northwest River Forecast Center as of April 1, 2024. This forecast results in a reduction to PSE's hydroelectric supply of 371,023 MWh relative to the normal hydroelectric forecast included in rates for 2024. This reduction to hydroelectric supply increases PSE's power cost forecast by $26.5 million for the last nine months of 2024.

Q. Why do lower projected hydroelectric volumes increase PSE's power cost forecast?

A. Less hydroelectric supply in PSE's portfolio requires PSE to purchase additional supply from the wholesale market and/or reduces the volume of surplus available for PSE to sell to the wholesale market. The power costs associated with PSE's hydroelectric resources are mostly fixed (*i.e.* they do not vary with the volume of production), so there is little to no offsetting savings associated with the lower volumes. Further, PSE's forecast assumes replacement of lost hydroelectric volumes with comparable CETA-eligible clean energy. PSE expects to pay a premium for specified clean energy supply relative to generic, unspecified market purchases. This premium accounts for $11.1 million of the total estimated $26.5 million increase to 2024 power costs from reduced hydroelectric production.

Q. Could actual power costs for the remainder of 2024 turn out to be lower than PSE's forecast, reversing the projected under-recovery and customer deferral?

A. Actual power costs for the remaining nine months of 2024 will almost certainly vary from the forecast included in PSE's current projection due to inevitable variation in demand, market prices, resource availability, and other power cost variables. But it is unlikely that any such differences between actual results and the current forecast could meaningfully offset PSE's under-recovery during the first quarter of 2024. Periods of relatively extreme weather and market conditions like those experienced in January can drive power costs well above those included in rates (which assume normal conditions), but it is not probable that any future extreme weather and/or price event could move power costs in the opposite, offsetting direction. Further, the under-recovery that PSE projects for the last nine months of 2024 is attributable to forecasts of low hydroelectric production. These forecasts have remained consistent for several months and it is already too late in the water year to expect any meaningful changes in snow accumulation, a primary driver of water supply and hydroelectric production through the summer months.

VI. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.