2026 POWER COST UPDATE

UPDATE TO FORECASTED COSTS IN THE PCA BASELINE RATE FOR 2026

PUGET SOUND ENERGY
DOCKET UE-250326

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

OCTOBER 1, 2025

LIST OF ATTACHMENTS

Attachment A – 2026 power cost forecast detail (confidential)

Attachment B – Power cost impact of resource portfolio changes (confidential)

Attachment C – Forecasted CCA emissions obligation in 2026 forecast (confidential)

BACKGROUND

The Settlement Agreement and Commission's Final Order in Puget Sound Energy's ("PSE") 2022 General Rate Case[1] ("GRC") adopted an annual update to the power cost forecast used to establish the Power Cost Adjustment ("PCA") variable baseline rate for each calendar year during the multi-year rate plan in that case. On September 29, 2023 PSE filed a 2024 Power Cost Update in Docket UE-230805 seeking to adjust the rate recovering PCA baseline power costs effective January 1, 2024 pursuant to the terms of the Settlement Agreement and the Commission's final order. On December 22, 2023 the Commission issued an order rejecting, in part, PSE's updated power cost forecast and directing PSE to refile its power cost update with modifications. On December 28, 2023 PSE filed revisions to its updated power costs and associated tariff sheets consistent with the Commission's order. The updated PCA baseline rate went into effect January 1, 2024

In its 2024 GRC,[2] PSE proposed continuation of the annual power cost update process adopted in the 2022 GRC, with modifications including several minor language updates and a three-month extension of the time for parties to review a preliminary forecast and any forecast methodology changes. PSE's proposal called for a preliminary forecast and description of methodology changes to be filed by April 30th of the year prior to the year for which an updated power cost forecast and PCA baseline rate would be in effect.[3] The forecast is then updated with final assumptions and inputs by October 1st for inclusion in the PCA baseline rate effective January 1st. The Commission's final order in PSE's 2024 GRC allows annual power cost updates consistent with PSE's proposal for the duration of the multi-year rate plan.[4]

Pursuant to the Commission's final order, on April 30, 2025 PSE submitted a preliminary power cost forecast for calendar year 2026 along with discussion and analysis of forecast methodology changes PSE proposes to enhance forecast accuracy and reduce the likelihood of material PCA over- or under-recoveries[5]. The discussion below summarizes PSE's updated forecast of power costs for 2026.

1. Summary of 2026 power cost update

This 2026 power cost forecast includes updated inputs and assumptions – including commodity prices, transmission expense, and known changes to PSE's electric

[1] Appendix A paragraph 29 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
[2] Dockets UE-240004, UG-240005, and UE-230810, consolidated
[3] See Mueller, Exh. BDM-1T at 42:16 – 47:19
[4] Order 09, Final Order in UE-240004 & UG-240005 at paragraph 381. Note that while PSE's proposal called for annual power cost updates to continue indefinitely, the Commission's final order accepted a proposal from the Alliance for Western Energy Consumers that limits annual updates to the duration of a multi-year rate plan.
[5] Docket UE-250326

resource portfolio – that will be in effect in calendar year 2026. The update also incorporates improvements to PSE's forecast methodology that were presented and discussed in PSE's April 30, 2025 filing in this docket. In addition to these updates, the 2026 forecast reflects PSE's proposed treatment of Climate Commitment Act ("CCA") allowance costs and benefits pursuant to Commission Order 01 in Docket UE-250321. Please see PSE's October 1, 2025 compliance filing in that docket for additional detail and discussion regarding PSE's proposal.

Overall, this power cost update reflects a significant increase to the costs included in PSE's PCA variable baseline rate. However, nearly half of this total increase ($316 million) is due to inclusion in power costs of CCA allowance costs that were not previously included, combined with operational assumptions intended to minimize such costs. Section 4 below discusses in more detail the CCA-related assumptions in this forecast.

Further, the large nominal increase in power costs does not reflect the value of no-cost CCA allowances that PSE expects will be surplus to its compliance requirements in 2026. Based on PSE's supply and demand forecast approved by the Commission on June 26, 2025 and the emissions obligation in this 2026 forecast, PSE projects it will have surplus 2026 allowances worth over $115 million. These allowances will reduce customer rates by offsetting compliance obligations in other years or via direct credits of revenue generated from consigning them to auction. The projected 2026 allowance surplus contrasts with PSE's 2025 allowance deficit that is currently in rates in Schedule 111E per Docket UE-250321, which was valued at $93 million.[6] While not directly reflected in the power cost forecast described herein, this $208 million beneficial year-over-year change in net allowance costs should be considered alongside the higher PCA variable costs in this filing. As demonstrated in Table 2 below, when viewed together, the nominal change in this filing of $709.3 million is significantly offset by these factors for a much lower comparative effect of $265.4 million.

Updates to PSE's electric resource portfolio are another primary driver of the 2026 power cost increase relative to the 2025 forecast, accounting for about 25 percent of the total increase ($182 million). These portfolio changes are primarily the result of new resources PSE acquired to provide capacity and reliable electric supply. Removal of Colstrip and the Centralia coal power purchase agreement from the portfolio on January 1, 2026 are a significant driver of the new capacity need. New resources acquired in pursuit of PSE's Clean Energy Transformation Act ("CETA") also impact the 2026 power cost forecast. Section 2 below discusses all of these electric portfolio changes and their impact on the 2026 power cost forecast. Two other drivers of increased power costs in 2026, updated commodity prices ($70 million increase to net power costs) and transmission expense ($58 million increase to net power costs) are also discussed in Section 2.

Forecast methodology updates applied in this 2026 forecast account for just over 10 percent ($80 million) of the total increase relative to the 2025 forecast currently in rates.

[6] July 3, 2025 revised filing in Docket UE-250321

PSE's power cost forecasts in recent years have been consistently lower than actual power costs, causing significant PCA variances. For PSE's customers, these variances (generally under-recoveries) drive rate instability and a potential mismatch between those receiving the benefits of PSE's power supply operations and those ultimately paying the costs. For PSE, PCA under-recoveries negatively affect cash flow and strain financial performance. Between 2019 and 2025 PSE's combined PCA under-recovery is $525 million, compared to just $18 million during the combined first 17 years of the PCA mechanism. Approximately 66 percent of the recent $525 million under-recovery was deferred according to the PCA sharing bands for collection from customers. The remaining $178 million was paid by PSE and will not be recovered in customer rates. These are prudently incurred expenses for which PSE cannot seek recovery. The methodology updates used in this forecast address these persistent under-recoveries by better aligning forecasted power costs with the power costs PSE actually expects to incur in 2026. They are discussed in more detail in Section 3 below.

Table 1 below summarizes the primary drivers of the increase to PSE's 2026 power cost forecast relative to the forecast for 2025 that is currently in rates.

Table 1: Summary of changes driving 2026 power cost forecast increase *($ in millions)*

2025 power cost forecast:	$1,222
CCA in forecast and dispatch:	$316
Resource portfolio updates:	$182
Commodity prices:	$70
Transmission expense:	$58
Forecast methodology updates:	$80
Other:	$3
Total increase:	$709
2026 power cost forecast:	$1,931

Table 2 on the following page provides a comparison of the 2026 power cost forecast to the 2025 forecast that is currently in rates, organized by FERC accounting categories. **Attachment A** includes the detailed costs and calculations supporting this 2026 forecast.

Table 2: 2026 power cost forecast versus 2025 forecast

($ in thousands)	Updated 2026	Current rates (2025 forecast)	Increase / (decrease) vs current rates
Coal fuel	$0	$54,423	($54,423)
Natural gas fuel	$316,564	$487,447	($170,883)
Wind and solar purchases	$89,172	$79,709	$9,463
Hydro purchases	$342,943	$453,066	($110,122)
Market purchases	$277,976	$85,032	$192,943
Other contract purchases	$714,453	$463,029	$251,424
Secondary sales	($250,632)	($491,571)	$240,939
Transmission	$229,980	$169,429	$60,551
Other revenues	($67,515)	($117,969)	$50,454
Demand Response	$19,083	$16,618	$2,465
Other power supply expense	$23,662	$22,547	$1,115
WA CCA allowance costs	$235,339	$0	$235,339
Total Power Costs	**$1,931,026**	**$1,221,761**	**$709,264**
Remove direct CCA allowance costs	*($235,339)*	*$0*	*($235,339)*
Add no-cost allowance (surplus) / deficit	*($115,426)*	*$93,101*	*($208,527)*
Year-over-year comparable costs	***$1,580,261***	***$1,314,863***	***$265,399***

2. Updated inputs and assumptions

Electric resource portfolio changes

PSE's 2026 electric portfolio includes significant changes from the 2025 forecast. Three of these resources – the Grays Harbor Energy Center Tolling Agreement, the Brookfield Hydro power purchase agreement ("PPA"), and a new Mid-C Wells PPA executed with Douglas County Public Utility District ("PUD") in 2024 –were discussed in PSE's April 30, 2025 preliminary forecast of 2026 power costs and also received a prudence determination in Order 01 in Docket UE-250318. PSE has added ten additional power supply contracts since that time: a contract with Grant County PUD for hydro output sold in its annual power auction for 2026, a PPA for firm capacity and energy from the Klamath Cogeneration facility, a PPA with Dynasty Power for firm capacity and energy, and seven distributed energy resource ("DER") PPAs. Six of these DER PPAs also received a prudence determination in Docket UE-250318.[7] A prudence request will be made in a future proceeding for the Dynasty, Klamath, Grant 2026 Auction and the

[7] Auburn 3, Kent 3, Oaksdale, Renton 6, Sumner 28, and West Valley 2. Prudence for the Renton Solar DER PPA will be requested in a future proceeding.

Renton 6 DER contracts. Collectively, these new supply resources increase 2026 power costs approximately $244.0 million relative to the 2025 forecast.

Three additional resources were included in the 2025 forecast but were only available for part of that year. Including Beaver Creek Wind, the Vantage Wind PPA, and the Freddy 1 Tolling Agreement in PSE's portfolio for all 12 months of 2026 reduces the forecast approximately $29.3 million relative to the 2025 forecast.

Resources removed from PSE's electric portfolio before the start of 2026 include Colstrip Units 3&4 and the Centralia Coal PPA. Replacing low-cost Colstrip energy output at current market prices increases 2026 power costs approximately $86.6 million while replacing energy supplied from the Centralia PPA reduces 2026 costs by $20.4 million (the price of the Centralia PPA was higher than the current forecast of 2026 market prices).

Other supply contracts that expire before 2026 include a contract with Chelan County PUD for 5 percent of the output from its Mid-Columbia hydro system, a contract with Grant County PUD for hydro output sold in its annual power auction, a contract with Eugene Water and Electric Board for output from the Stateline Wind project, and multiple near-term capacity agreements that PSE acquired via requests for proposals issued in 2023 and 2024. Collectively, these contract expirations drive an approximately $98.5 million reduction in PSE's preliminary 2026 power cost forecast relative to the 2025 forecast. Note that these values, and those reported for Colstrip and Centralia above, account only for the net cost of replacing energy from these resources. The cost of replacement capacity is reflected in the increase associated with new resource additions. PSE replaced the capacity from these agreements with new supply from the Klamath Cogeneration PPA, Dynasty Power PPA, and Grays Harbor Tolling Agreement in order to meet 2026 resource adequacy needs.

Table 3 on the following page summarizes changes in PSE's 2026 electric resource portfolio relative to 2025 with the approximate power cost impact of each. **Attachment B** includes additional detail for each resource and PSE's calculation of estimated power cost impacts.

***Table 3: Resource portfolio changes in 2026 power cost forecast** ($ in thousands)*

Resource/PPA Name	Status	Power Cost Impact
Grays Harbor Tolling	Added	$121,852
Brookfield Hydro PPA	Added	$16,489
Dynasty Power	Added	$36,000
Klamath Cogen	Added	$20,783
Mid-C Wells 2024 PPA	Added	$21,749
Grant 2026 Auction	Added	$26,786
7 DERs	Added	$386
Freddy 1 Tolling	Continued	$3,924
Vantage Wind PPA	Continued	($573)
Beaver Creek Wind	Continued	($32,658)
Chelan 5% Slice	Removed	($22,958)
Grant 2025 Auction	Removed	($33,157)
Colstrip	Removed	$86,603
Centralia Coal PPA	Removed	($20,407)
Stateline Wind	Removed	($848)
2023 and 2024 RFPs	Removed	($41,548)
	Total	**$182,423**

Commodity prices

PSE updated natural gas prices in the 2026 power cost forecast using average forward market prices over the 90-days ended September 5, 2025. Average Sumas gas prices for 2026 increased 5 percent from $3.96 per MMBtu in 2025 to $4.15 per MMBtu in 2026. At the same time, upstream prices in British Columbia and Alberta rose more significantly, with Station 2 up 37 percent and AECO up 39 percent relative to PSE's 2025 forecast. These smaller spreads between upstream and market-area prices reduce the calculated benefit from PSE's pipeline capacity, driving approximately $33.6 million of the total $50.4 million forecasted cost increase in FERC Account 456 ("Other revenues"). The remaining increase results from an updated methodology for estimating economically transported gas volumes, discussed in Section 3.

Power prices in the 2026 forecast are approximately 10 percent lower than PSE's 2025 forecast. PSE's power price forecast relies on fundamental price drivers for the Western Electric Coordinating Council (WECC) region, including demand, supply, transmission, and generator characteristics from Energy Exemplar's Aurora model database. The 2026 forecast uses database version v25.3 (released March 31, 2025) versus the November 2023 version used in 2025. The newer version includes additional renewable energy supply in the WECC region, explaining why 2026 power prices are lower despite higher natural gas and CCA allowance prices.

PSE updated CCA allowance prices using the average nodal exchange price for 2026 vintage allowances over the 7 days ended September 5, 2025. CCA prices increased 23 percent from $53.25/MTCO2 in 2025 to $65.61/MTCO2 in 2026.These commodity price updates drive a net power cost increase of approximately $70 million, primarily due to reduced secondary market sales revenue. Forecasted wholesale sales revenue dropped from $492 million in 2025 to $251 million in 2026. Lower secondary sales result from both reduced power prices (lower revenue per unit) and decreased sales volumes, as lower market heat rates make PSE's gas-fueled generators less economic to operate, reducing surplus energy available for sale. This revenue reduction is only partially offset by $171 million in lower natural gas fuel expenses.

Purchased transmission expense

Transmission expense in PSE's 2026 power cost forecast increased $60.0 million compared to the 2025 forecast. The largest driver is a 24 percent increase to Bonneville Power Administration (BPA) transmission rates effective October 1, 2025, per BPA's published BP-26 rate schedules, contributing approximately $27.3 million (46 percent of the total increase). PSE's 2024 GRC had assumed only a 5 percent BPA rate increase based on historical patterns.

The remaining increase to PSE's 2026 purchased transmission expense is due to:

a. A transmission contract with Northwestern Energy for delivery of output from the Beaver Creek wind project: This transmission was included in the 2025 forecast but for only the last two months of the year during which Beaver Creek was expected to be operational ($10.8 million increase relative to 2025 forecast).

b. Additional firm BPA transmission for delivery of output from the Freddy 1 tolling agreement: This transmission was also included in the 2025 forecast but for only the last three months of the year during which the tolling agreement is effective ($3.0 million increase relative to 2025 forecast).

c. BPA transmission acquired as part of the Grays Harbor tolling agreement: PSE acquired 300 MW of additional firm BPA transmission for delivery of a portion of the output from the Grays Harbor tolling agreement. The Grays Harbor tolling agreement began January 1, 2025 but was not included in the power cost forecast used to establish the 2025 PCA baseline rate ($8.8 million increase relative to 2025 forecast).

d. BPA transmission associated with a summer capacity contract executed pursuant to PSE's Q4 2024 near-term request for proposals: the capacity PPA begins in summer 2025 and was included in PSE's 2025 power cost forecast, with the associated transmission costs now properly reflected in the 2026 forecast ($1.9 million increase relative to 2025 forecast).

e. The estimated cost of secondary/non-firm transmission purchases needed to support forecasted wholesale sales of surplus generation in excess of PSE's long-term firm transmission rights ($2.7 million increase relative to 2025 forecast). This estimated transmission expense was not included in PSE's 2025 power cost forecast and is the result of the proposed methodology update discussed in Section 3 below ("Transmission limits in Aurora model").

3. Forecast methodology

This 2026 power cost forecast incorporates updates to PSE's forecast methodology relative to the methods used for the 2025 forecast currently in rates. These changes are necessary to better align PSE's power cost forecast with more recent trends in hydroelectric production, current commodity market dynamics, and the realities of PSE's electric resource portfolio – which has changed significantly in recent years and will continue to evolve. Collectively, these improvements add approximately $80 million to PSE's forecast of 2026 power costs. Table 4 below summarizes the impact of each change.

***Table 4: Summary of impact to 2026 forecast from methodology changes** ($ in millions)*

1.) Demand/price volatility adjustment	$53.5
2.) Transmission limits in Aurora model	$2.7
3.) Gas pipeline utilization	$16.9
4.) Hydro volumes update	$6.4
Increase attributable to methodology updates	**$79.5**

Demand variability and price correlation adjustment

PSE's 2026 power cost forecast includes an estimate of incremental power costs to account for variability in retail demand and power prices, as well as the correlation between changes in these variables. PSE's power cost model uses normalized demand and power price assumptions; though actual results will always vary from forecasts. While each variable is expected to average to normal over time, their high correlation creates a systematic cost impact that does not average out.

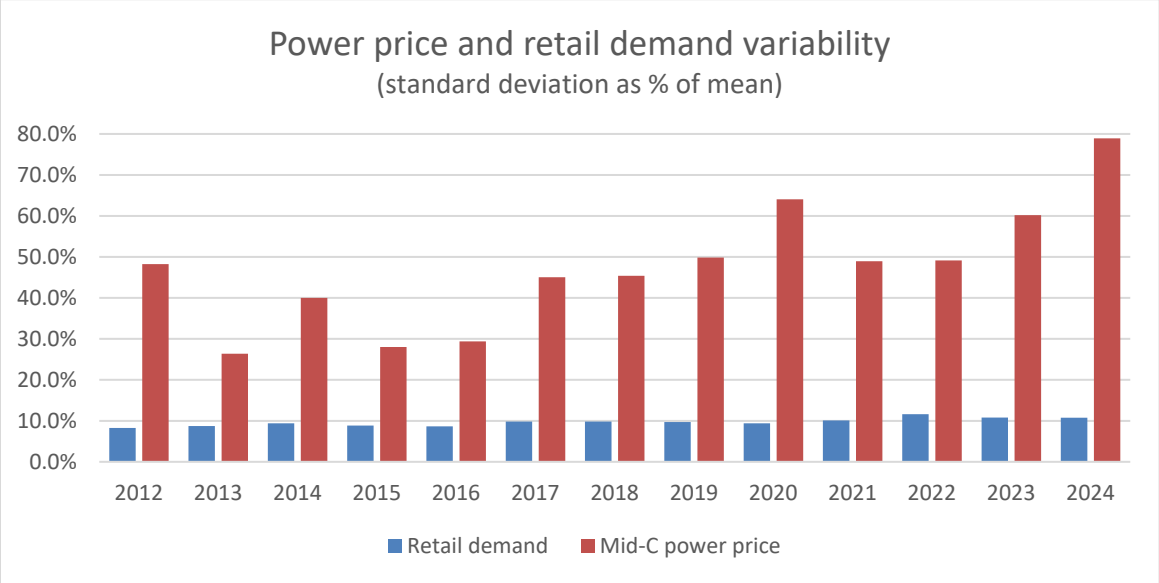
When demand exceeds forecast, power prices are also likely higher than normal, requiring PSE to serve increased demand through relatively expensive market purchases. Conversely, when demand is below forecast, power prices are typically lower than normal, reducing the revenue benefit from surplus sales. This correlation creates an asymmetric cost impact: the expense of serving higher-than-forecast demand during high-price periods is never fully offset by revenue from surplus sales

during low-demand, low-price periods—even though demand itself averages to normal over time.

Therefore, normalized model inputs for demand and price do not yield a normalized power cost forecast, necessitating an incremental cost adjustment.

The need for this power cost forecast adjustment has become increasingly apparent as variability in both demand and power prices has grown in recent years. Figure 2 shows the standard deviation of Mid-C power prices and PSE's retail demand from 2011 through 202, clearly demonstrating increased price variability over time. These increases in variability coincide with growing PCA under-recoveries at PSE.

Figure 1: Variability in power prices and PSE demand



PSE's methodology for calculating power cost increases from demand and price variability uses historical data from 2012 to 2024. PSE calculated correlations and standard deviations between power prices and actual demand on annual, monthly, and daily bases. These values serve as inputs for Aurora model's risk sampling tool, which generates simulations of power price and demand risk factors for each time period. The risk factors are aggregated monthly to determine the adjustment needed in PSE's deterministic power cost model to account for variability. This methodology increases forecasted 2026 power costs by approximately $53.5 million, which is lower than the $66 million estimate in PSE's preliminary 2026 forecast due to overall lower power prices in this update.

Transmission limits in Aurora model

PSE updated transmission assumptions in its Aurora model for the 2026 power cost forecast. Previously, PSE did not impose limits on the transmission capacity available for exporting power to the wholesale market. While such limits have always existed

operationally, they were not restrictive enough to impact Aurora modelling. However, as PSE's generation portfolio grows to meet capacity and renewable energy requirements, energy exports during surplus periods increasingly exceed PSE's firm transmission capability. The forecast update limits modeled transmission export capability at zero incremental cost to PSE's available firm transmission rights (approximately 1,500 MW). For exports above this amount, the model includes an incremental cost for short-term non-firm transmission. When economically viable, Aurora calculates this incremental transmission cost and includes it as transmission expense in PSE's 2026 power cost forecast. The estimated total for 2026 is $2.7 million, lower than the $5.2 million in PSE's preliminary forecast due to reduced expected surplus/exports from lower power prices and higher gas prices.

Gas pipeline utilization

PSE's 2025 forecast methodology assumed PSE could economically utilize all available capacity to both minimize fuel supply costs and generate net revenues to reduce power costs by purchasing from lower-priced delivery points and re-selling gas at higher-priced locations. In practice, PSE generally cannot optimize pipeline capacity for both purposes simultaneously. This forecast aligns projected pipeline capacity benefits with what PSE can realistically achieve in actual operations.

First, the forecast limits economically transported gas volumes between low-priced Canadian supply locations and higher-priced demand locations in PSE's geographic area to be consumed as fuel.

Second, the forecast eliminates the assumption that PSE can optimize apparent price spreads between locations within PSE's geographic area (Sumas and Stanfield). Forward market price spreads reflect expectations of potential pipeline constraints between these locations. However, if constraints occur, PSE cannot physically move gas to capture the spread benefit. If constraints don't materialize, the price spreads disappear in actual market prices.

These updates to PSE's pipeline optimization methodology reduce projected total benefits in 2026 by approximately $16.9 million. This is higher than the $11.3 million estimate in PSE's preliminary forecast due to lower forecasted utilization of gas-fueled generators, resulting in more surplus pipeline capacity for which PSE no longer projects net revenue.

Hydroelectric volumes: update to new 30-year "normal"

In its 2024 Power Cost Forecast Update PSE changed its methodology for determining "normal" hydroelectric production from median volumes based on 80 years of historical streamflow data (1929 to 2008) to using the median of a more recent 30-year period (1992 through 2021 in that case). In this 2026 power cost forecast PSE continues to utilize median hydro based on 30 years of historical streamflow data as inputs to its power cost model. However, PSE updated the 30-year period to incorporate more recent data. The hydro volumes used in this forecast are the median volumes based on historical stream-flows from August 1995 through July 2025. Incorporation of the 2022

through July 2025 data reduces PSE's forecasted hydroelectric supply in 2026 by approximately 1.3 percent relative to the prior forecast methodology. This reduction drives a net power cost increase in PSE's 2026 forecast of approximately $6.4 million (this is higher than the $4.3 million estimate provided in PSE's preliminary 2026 forecast because that forecast was based on hydroelectric streamflows through only December 2024 – inclusion of relatively low hydro from January through July 2025 in this update reduces the 30-year median).

4. Climate Commitment Act allowance obligation and effect on resource dispatch

Cost of allowance obligation

Consistent with PSE's proposal for compliance with Commission Order 01 in Docket UE-250321, this 2026 power cost forecast includes the estimated cost of CCA allowances as a PCA variable cost. As described in PSE's October 1, 2025 compliance filing in that docket, this treatment aligns the cost of PSE's CCA compliance obligation with the benefits of incurring that obligation, namely, wholesale electricity market sales revenue and/or reduced costs for wholesale market purchases. This proposed treatment also allows the risk of variance in PSE's CCA compliance costs to be shared according to the same PCA mechanism that provides sharing of other variable power costs. Market purchase costs, market sales revenue, and fuel costs – and commodity price exposure that drives variances – are all already in the PCA. The volume, price, and resulting cost of emissions/allowances should be no different. All of these things are interrelated and change relative to forecast according to market conditions and PSE's operational decisions – they belong in the same bucket for recovery and risk sharing purposes.

PSE's 2026 power cost forecast includes $235 million of direct CCA compliance cost associated with the forecasted emissions obligation from its generating resources and imports from out-of-state sources in 2026. Importantly, this $235 million included in PCA power costs is exactly offset by a proposed $235 million customer credit in a separate rate schedule (Schedule 111) that will be filed by October 31, 2025. This credit represents the value of no-cost allowances that PSE will use to cover its forecasted emissions obligation in 2026. Including CCA compliance cost in the PCA, therefore, does not increase customer cost or rates overall, it simply aligns the cost recovery mechanism with the associated benefits while enabling variances to be tracked and the risk of any such variances to be shared according to existing PCA principles.

Estimated GHG emissions in this 2026 forecast are determined using the same Aurora model outputs used for the other variable power costs included in the forecast. Emissions from PSE plants are (and for some time have been) calculated by the Aurora model, PSE has just not directly relied upon that output to establish the PCA baseline rate in the past. Utilizing the same Aurora model and input data set for emissions as for other power costs ensures internal consistency in the forecast and the assumptions used to establish all variable power costs. **Attachment C** includes details of PSE's

estimated 2026 emissions obligation and the resulting $235 million compliance cost included in this forecast.

CCA cost in generator dispatch decisions

This 2026 power cost forecast includes the CCA compliance cost of GHG emissions in the dispatch cost of all PSE resources regardless of whether the resource is expected to be used directly for retail load or to supply a wholesale (secondary) market sale. PSE's 2025 power cost forecast included CCA compliance cost only in the dispatch cost of resources surplus to retail load. This change in PSE's approach to CCA costs in dispatch is the result of recent information from Department of Ecology regarding adjustments to a utility's no-cost allowance allocation pursuant to WAC 173-446-230(2)(g).[8]

In its 2024 general rate case, PSE and WUTC Staff both discussed the merits and expected impacts of including CCA cost in all dispatch decisions vs only on plants that are surplus to retail load requirements.[9] As discussed therein, including CCA costs in all dispatch decisions increases traditional net power costs (fuel, market purchases, and market sales) while also reducing emissions from PSE's plants. Whether the benefit of this emissions reduction is sufficient to offset the increase in traditional power costs depends on how or whether Department of Ecology will adjust a utility's no-cost allowance allocation based on actual reported emissions.

At the time of the 2024 GRC, PSE understood that Ecology would adjust PSE's allowance allocation based on actual results, preventing monetization of any surplus allowances created by the reduction to actual emissions. Given this understanding, total customer costs are minimized when CCA costs are included only in the dispatch cost of plants being used for wholesale sales. UTC Staff, on the other hand, believed that Ecology would not adjust PSE's allowance allocation based on actual results and that any surplus allowances associated with an emissions reduction could be monetized for customer benefit. Given Staff's proposed methodology, total customer costs are minimized when CCA costs are included in the dispatch cost of all PSE plants all the time. Information provided by Ecology over the past year, including draft guidance regarding no-cost allowance adjustments, indicate that Staff's understanding was correct, at least with respect to calendar year 2026 and beyond. PSE therefore intends to include CCA costs in the dispatch cost of all plants, regardless of whether they are used for wholesale sales or retail load, during 2026. Table 5 below provides a comparison of 2026 power costs with CCA included only in the dispatch cost of plants utilized for wholesale sales vs including CCA in all dispatch decisions.

[8] *WA Department of Ecology, Cap-and-Invest Electric utility allocation workshop July 22, 2025,* Cap-and-Invest: No-cost allowance allocation for electric utilities, *slide 50: "*Ecology will **not** seek adjustments related to 1.) Market-optimization behavior resulting in lower covered emissions or cost burden relative to forecasts base on best estimates of retail supply at the time, 2.) Additional or overachievement of decarbonization or efficiency efforts relative to forecasts based on best estimates of retail load or supply at the time."

[9] Docket UE-240004. See rebuttal testimony of Brennan D. Mueller, Exh. BDM-23CT pp. 24-28

Table 5: Comparison 2026 forecast with CCA in all dispatch decisions vs only for wholesale sales

	CCA only for wholesale sales	CCA in all dispatch	Increase / (decrease)
Forecasted "traditional" power costs	$1,615,056	$1,695,687	$80,631
PSE emissions (metric tons)	5,095,487	3,586,934	(1,508,554)
Cost of emissions	$334,315	$235,339	($98,976)
Total cost	**$1,949,371**	**$1,931,026**	**($18,345)**

As shown in Table 5 above, inclusion of CCA allowance costs in all dispatch decisions increases traditional power costs approximately $81 million while reducing GHG emissions. The value of this emissions reduction, whether in the form of reduced compliance costs or surplus no-cost allowances available for consignment, more than offsets the increase in traditional power costs, providing a net overall reduction of $18 million to 2026 power costs. Including CCA allowance costs in all dispatch decisions is expected to minimize power supply costs for PSE's customers. PSE intends to employ this cost-minimizing strategy in actual operations during 2026 and it is reflected in this 2026 power cost forecast submitted with this filing.