DPU Data Request 1.2

Semi-Annual Hedging Report – February 2026. In regard to the Chehalis variable operating and maintenance (VOM) adder mentioned on page 35 of PacifiCorp's Semi-Annual February 13, 2026, hedging report:

(1) Please explain what it is and why it is used.

(2) How is it implemented?

(3) When was it first implemented?

(4) Please provide the values of the adder since first implementation.

Response to DPU Data Request 1.2

(1) The variable operating and maintenance (VOM) cost adder represents costs associated with a generating unit, expressed on a dollars per megawatt-hour ($/MWh) basis. It functions as an adder to fuel costs in the optimization routine, ensuring that the model is fully informed regarding all variable costs associated with a generating unit, not just fuel costs.

(2) The PCI Energy Solutions (PCI) optimization model includes a field that houses VOM costs for each generating unit. The implementation is simply having a value entered into that field.

(3) VOM adders been included in PCI since the model was initially implemented and served a role in the prior position measurement methodology through a cost adder in ENDUR as well. Incorporation of VOM costs into dispatch decisions is an industry standard practice.

(4) Please refer to Confidential Attachment DPU 1.2 which provides the VOM adders used for Chehalis since implementation.

As found in Confidential Attachment DPU 1.2:

DPU Data Request 1.3

CONFIDENTIAL REQUEST – Semi-Annual Hedging Report – February 2026. On page 35 of the Hedging Report, [redacted]. Please provide more details on why there is a [redacted].

Confidential Response to DPU Data Request 1.3

[redacted] Based on the forgoing clarification, the Company responds as follows:

[redacted] Please refer to Confidential Attachment DPU 1.2 for details.

[redacted]

DPU Data Request 1.5

CONFIDENTIAL REQUEST - Semi-Annual Hedging Report – February 2026.
Confidential Figure: Position Composition – 4 and 7 on pages 14 and 15. Please provide more details on the [redacted]

Confidential Response to DPU Data Request 1.5

[redacted]

DPU Data Request 2.3

Semi-Annual Hedging Report – February 2026. Please provide a written response to Commission Question No. 1 from the Closed Technical Conference on March 5, 2026, in Docket No. 26-035-03.

The Company assumes that the reference to "Commission Question No. 1" from the March 5, 2026 Closed Technical Conference in Docket 26-035-03 is intended to be requesting a response to the following request:

What is the average cost of long-term contracts per MWh over the previous five years?

(a) With the loss being calculated as the all in purchase price minus the revenue from resale, how much is the average loss at resale for the unused portions of those contracts at resale?

(b) What is the total amount of MWh of production from PacifiCorp's owned or controlled resources taken offline, or simply never scheduled to run, when there is unused energy from long-term contracts? How frequently do either of those circumstances occur? Please answer with estimates covering multiple periods, e.g. for the duration of the contract, monthly, weekly, and daily to the extent practicable.

Response to DPU Data Request 2.3

The Company interprets "long-term contracts" to be forward market transactions. Based on the foregoing interpretation, the Company responds as follows:

Please refer to the table below which provides the average cost of fixed-price forward purchase contracts executed over the course of the past five years (2021 through 2025):

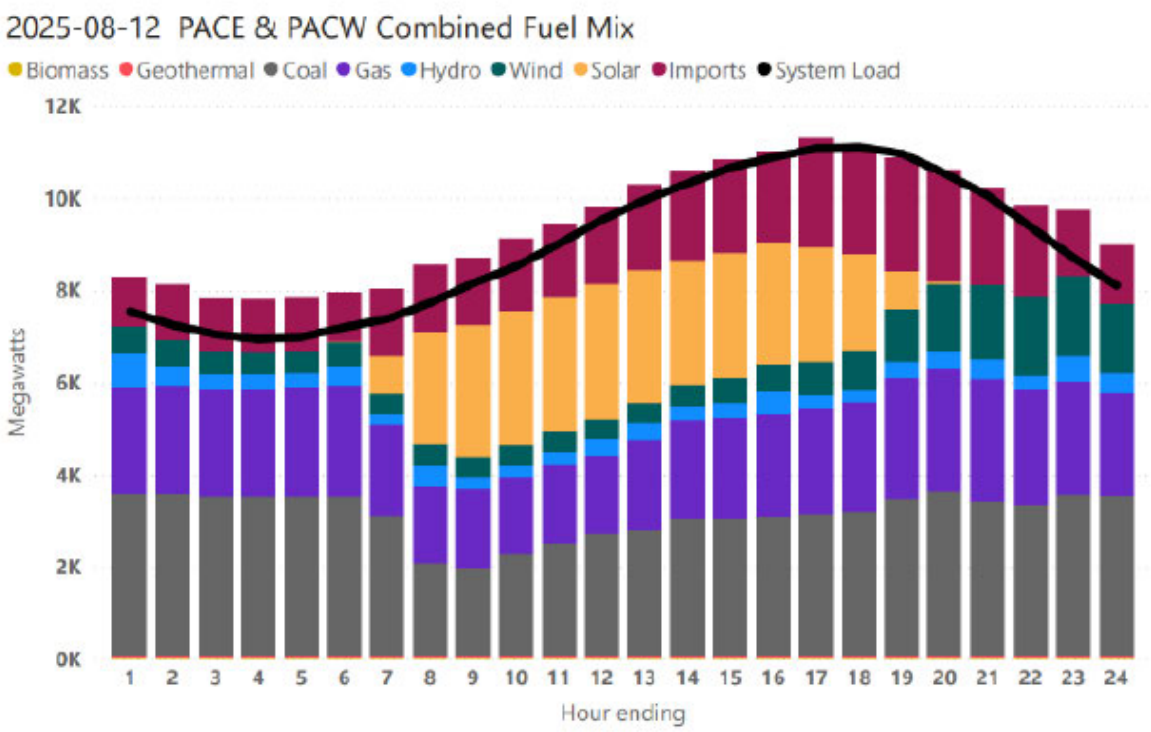
	Dollars per Megawatt-Hour ($/MWh)	
Year	**East**	**West**
2021	$28.58	$57.96
2022	$154.09	$82.59
2023	$142.31	$115.12
2024	$176.28	$130.19
2025	$12.00	$99.58

(a) Please refer to Confidential Attachment DPU 2.3, which compares fixed price forward purchases in the "NSS-TRANS_TERM" portfolio to spot market activity executed later in time, including both volumetric data and dollar values along with average prices. Note: there is no way to directly connect any purchase made on a forward basis to any sale made in the spot market, and the

Company regularly makes both purchases and sales over the course of any month or quarter. This applies both to quarters when no forward purchases were made, and to quarters when forward purchases were executed. For that reason, net spot activity is depicted in Confidential Attachment DPU 2.3, and the rare instances when the Company was a net seller after having made purchases in the forward market have been highlighted for ease of reference. Also, please note that the forward volumes depicted in Confidential Attachment DPU 2.3 may, in some cases, include purchase volumes that were a part of spread transactions, which the Company executes in order to monetize its transmission rights to the benefit of customers. For that reason, the term purchase volumes depicted in Confidential Attachment DPU 2.3 may be slightly larger than the net positions would have been if sales had been included in the forward position.

b) PacifiCorp interprets this question as asking to quantify times when the Company purchased term energy but chose to dispatch other owned resources offline. PacifiCorp does not have the data readily available to quantitatively answer this question. Dispatching thermal generation off-line during times of the day when there is energy oversupply is not an uncommon occurrence, and doing so leads to lower net power costs (NPC) for customers.

The primary reason that there would be hours when PacifiCorp chooses to economically cycle thermal resources off-line when the Company has purchased term contracts is because of how these contracts are structured. The Company does not need energy equally for all 16 hours of a heavy-load hour (HLH) block purchase, but this is the primary product available in forward power markets. Because the load shape is not flat, positioning the system to serve a system peak hour can naturally result in over-supply conditions for non-peak hours. If it is economical, the Company may choose to cycle plants offline to facilitate cheaper imports, or if the resources are economic, they may be incremented to facilitate economic sales in the California Independent System Operator's (CAISO) Western Energy Imbalance Market (WEIM). One of the benefits of CAISO Extended Day-Ahead Market (EDAM) is that the market can make optimal commitment decisions for these thermal resources with long start-up and shut-down times.



The chart above shows the reality of positioning the PacifiCorp East (PACE) system to meet peak load in the summer. During solar hours, coal and gas generation is decremented to allow for cheaper renewable generation to flow. As solar generation decreases in the late afternoon, gas and coal generation is needed to quickly ramp up to offset the reduction in renewable output. Peak gross load occurs in hour ending 18, but peak net load (load minus renewables) occurs hour ending 20, when solar output is almost completely gone, but loads remain high. During the peak net load hour, gas and coal generation is at its peak, even higher than during the light-load hours (LLH) (1-6, 23-24) when imports are much lower. To meet load during the peak hour requires all thermal generation, in addition to market purchases.

This is a challenge that many utilities in the West face. The integration of batteries will help mitigate the issue, charging during solar hours when there is surplus renewable generation, and discharging over the peak when solar output is reduced.

The problem is exacerbated for PacifiCorp because the system is net capacity short in the summer months and forced to procure 16-hour block purchases out the curve. As noted in the Company's response to subpart (a) above, these block purchases are needed on most days, as the volume of net spot sale activity is much less than the volume of term purchases.

DPU Data Request 2.5

Semi-Annual Hedging Report – February 2026. Please provide a detailed explanation of the methodology used to calculate the proposed Planning Reserve Margin for the new risk management program, including underlying formulas, reliability metrics, and data inputs.

Response to DPU Data Request 2.5

The planning reserve margins (PRM) to be used in determining the capacity position under the new risk management program are based on the PRMs used in the PacifiCorp's 2025 Integrated Resource Plan (IRP) for the months of July and December (they were adopted for summer and winter, respectively). The IRP adopted those PRMs from the Western Resource Adequacy Program (WRAP), therefore, PacifiCorp has no work papers to provide.

For further details in the IRP's use of PRMs, please refer to PacifiCorp's 2025 IRP, Volume I, Chapter 6 (Load and Resource Balance), section "Capacity Balance Determination" commencing page 130. PacifiCorp's 2025 IRP is publicly available and can be accessed by using the following website link:

Integrated Resource Plan