Exh. RJM-13CT
Docket UE-250224
Witness: Ramon J. Mitchell

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-250224

PACIFICORP

REDACTED REBUTTAL TESTIMONY OF RAMON J. MITCHELL

September 2025

TABLE OF CONTENTS

Q. Are you the same Ramon J. Mitchell who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. Please provide the purpose and a summary of your rebuttal testimony.

A. My rebuttal testimony responds to testimony from John D. Wilson, filed on behalf of Staff (Staff) of the Washington Utilities and Transportation Commission (Commission), Bradley G. Mullins, filed on behalf of the Alliance of Western Energy Consumers (AWEC), and Dr. Robert L. Earle, filed on behalf of the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel). Company witnesses, Isaiah M.R. Zacharia and Vijay R. Singh, also provide rebuttal testimonies addressing contested net power costs (NPC) issues. Specifically, witness Zacharia discusses various inconsistencies and inaccuracies in AWEC's NPC modeling, which AWEC uses to support their recommendations. Witness Singh discusses the reasonableness of Staff's proposed adjustment to Western Energy Imbalance Market (WEIM) benefits.

My rebuttal testimony's purpose is to assist the Commission in setting just and reasonable rates in this power cost only rate case (PCORC) by correcting key factual and conceptual errors in those testimonies, by explaining in plain terms how the Company develops an accurate total-company forecast of NPC and then allocates a Washington share, and by demonstrating that the Company's proposed methods—together with limited clarifications and improvements—are necessary and reasonable.

I begin by clarifying the two-step structure of this proceeding, which several opposing witnesses conflate. First, the Commission must establish an accurate system-wide forecast of Net Power Costs, which are the costs to generate, buy, sell, and deliver electricity hour by hour to keep the grid in balance. Second, the Commission must allocate a fair Washington share of those costs. I explain why accuracy at the total-company level is of critical importance to Washington customers.

I then address the principal disputed issues so that the Commission may decide them on a clear and reliable record. I show that the Company's forward-transaction modeling adjustment is a necessary recognition of the real cost of acquiring standardized forward energy blocks and shaping them to hourly needs, and that it is distinct from, and not double-counted with, the Company's day-ahead/real-time (DA/RT) adjustment modeling. I explain that the Company's treatment of wind and transmission does not penalize renewable resources; it reflects binding physical limits and reliability requirements that must be honored to keep service reliable. I demonstrate that Public Counsel's allegation of a large historical over-collection from short-term firm purchase accounting rests on a misunderstanding of a cost allocation's balancing step. I outline how contracts for curtailable industrial load provide necessary reliability support for Washington's generation portfolio. I provide support for the Company's production tax credit (PTC) rates update. Finally, I identify limited areas of agreement that improve accuracy—such as removing a redundant Bonneville Power Administration (BPA) real-power-losses wheeling line and eliminating an outdated Clean Energy Transformation Act (CETA) market premium—and I explain the uncontested, narrow way to incorporate changes at the time of the compliance filing.

In sum, the purpose of my rebuttal testimony is to provide the Commission a clear, accurate, and practical path to set rates: adopt an accurate NPC forecast that reflects how wholesale markets and the transmission system actually operate; apply a Washington allocation that is fair, transparent, and tied to cost causation; accept modest corrections that sharpen accuracy; and reject proposals that rely on conflating distinct activities, overlooking physical constraints, or misreading accounting safeguards. This approach yields rates that are stable while maintaining the reliability that modern electric service requires.

II. REBUTTAL

1. AWEC – NPC Forecast Accuracy

i. Foundational Concepts: How PacifiCorp Determines Future Power Costs

Q. To begin, please explain what "net power costs" are and why they are important.

A. "Net power costs," which we often abbreviate as NPC, are the variable costs the Company incurs to produce and purchase the electricity needed to serve our customers. Think of it like a household's monthly grocery bill. While your mortgage or rent is a fixed cost that stays the same each month, your grocery bill varies depending on how many meals you cook, the price of ingredients, and whether you eat out. Similarly, NPC are the variable costs incurred by the Company to provide service to customers. They change based on factors like weather, the market price of fuel, and customer demand.

These costs are comprised of several key components, which are tracked in specific accounts designated by the Federal Energy Regulatory Commission (FERC). The primary components are the cost of fuel, like natural gas and coal, that we use in our power plants; the cost of purchasing electricity from the wholesale market when it is more economical than generating it ourselves or when we need additional supply; and the cost of "wheeling," which is the fee we pay to use other entities' transmission lines to move power across the grid to where it is needed.

A very important part of this concept is the word "net." This is because our costs are offset by the revenue we earn from selling our surplus electricity into the wholesale market. When our resources generate more power than our customers need at a given time, we can sell that excess power. The money we make from those sales is used to reduce the total power costs that are ultimately passed on to customers. This is why we call them "net" power costs—they are the total cost of fuel, purchased power and wheeling, minus the revenue from our wholesale power sales. Understanding this is critical because NPC is one of the largest and most volatile components of a customer's bill. Forecasting these costs accurately is the most important step in setting rates that are fair, stable, and predictable for Washington families and businesses.

Q. What is the difference between forecasting NPC and then allocating NPC to Washington customers?

A. The distinction between forecasting and allocating is the single most important concept to understand in this proceeding. It is a two-step process, and getting the order and function of those steps right is essential.

The first step is **forecasting**. Forecasting is the act of predicting the future. To do this, we use a highly sophisticated and powerful simulation tool called the Aurora production cost model. This model predicts the total NPC for our entire, interconnected six-state system. To use an analogy, if we think of the total electricity cost for all our customers as one very large pie, the forecasting step is where we calculate the total cost of all the ingredients needed to bake that entire pie.

The second step is **allocation**. Allocation is the act of dividing up a cost that has already been determined. After the Aurora model has finished its complex work of forecasting the total cost of the pie, we then use a much simpler tool—a spreadsheet method—to slice that pie and determine Washington's fair share based on a set of agreed-upon rules. This is a standard accounting practice used to distribute shared costs.

AWEC has claimed that the spreadsheet method is "designed to forecast the NPC[.]"[1] This is factually incorrect. The spreadsheet does not and cannot forecast anything. It is an accounting tool that performs the second step: it takes the total costs forecasted by Aurora and determines the share of those total costs that are allocated to Washington. The calculations in the allocation spreadsheet are only as reliable as the total-company NPC forecast numbers that are input into the allocation spreadsheet. If the forecast for the whole pie is wrong, the slice allocated to Washington will be wrong too.

Q. Please describe the Aurora model and what it does.

A. The Aurora model is an industry-standard software tool that is known as a production cost model. The best analogy to understand what it does is to think of it as a flight

[1] Mullins, Exh. BGM-1CT at 17:16.

simulator for the entire Western United States' power grid.

Before a pilot ever flies a real plane, they spend countless hours in a simulator. That simulator is programmed with the laws of physics and the specific characteristics of the aircraft. The pilot can then test how the plane will perform under thousands of different potential conditions—perfect weather, heavy storms, engine trouble, and so on—all without leaving the ground. This ensures they know how to operate the plane safely and efficiently in the real world.

Aurora does the same thing for our power system.[2] We input a massive amount of data into the model, including the physical layout of the transmission grid, the operating characteristics of every single power plant in our system and our neighbors' systems, hour-by-hour forecasts for customer electricity demand, and projected prices for fuel like natural gas. The model then simulates an entire year of operations, one hour at a time, for all 8,760 hours. For each hour, Aurora's one objective is to find the absolute lowest-cost way to generate and deliver electricity to meet customer demand, all while respecting the real-world physical limits of the power plants and the transmission lines. The sum of these hourly costs gives us our total-company NPC forecast.

It is essential to understand that the model simulates the entire interconnected system because electricity does not recognize state borders. The flow of power is governed by the laws of physics across the whole grid. An accurate *forecast* therefore must be based on this physical reality, not on artificial accounting lines imposed after-the-fact in the spreadsheet method of allocating costs to Washington.

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[2] An explanation of electric utility production cost models is available at: https://www.simplethread.com/introduction-to-production-cost-analysis/ (last visited Sept. 8, 2025).

Q. Following that, what is the "spreadsheet method," and what is its specific job in this process?

A. The spreadsheet method is simply an accounting tool. Its only job is to perform the second step in our two-step process. As an analogy, once the Aurora model has determined that the total cost to bake the pie is $100, the spreadsheet method is the knife we use to cut Washington's specific slice.

The spreadsheet contains a set of mathematical formulas and percentages that have been established and reviewed in prior regulatory proceedings—or proposed to be established—such as the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) or the proposed 2026 Washington Protocol. It is not a physical simulation like Aurora. It does not understand how power plants operate or how electricity flows. It simply takes the total cost numbers from the Aurora forecast—for example, the total system-wide cost for natural gas fuel—and applies a percentage, or "allocation factor," to determine Washington's share of that specific cost category.

The spreadsheet method was approved and has been used because it is transparent and relatively straightforward. However, it is crucial to remember that the spreadsheet is just a calculator. The answers it produces are entirely dependent on the numbers that are put into it. If the total-company NPC forecast from Aurora is inaccurate—if the true cost of the whole pie is not $100 but $120—then the Washington-allocated slice calculated by the spreadsheet also will be inaccurate. This is why the accuracy of the initial, total-company forecast is not just relevant, but absolutely essential.

ii. The Necessity of an Accurate System-Wide Forecast

Q. AWEC's testimony states, "as a general principle . . . the accuracy of total-company NPC is not necessarily at issue."[3] Is that a correct assessment?

A. No. The accuracy of the total-company NPC forecast is the single most important factor in ensuring that the portion of those costs allocated to Washington customers is fair, just, and reasonable, as discussed above. In addition, the accuracy of the total-company forecast is critical to the proper operations of the Company's Power Cost Adjustment Mechanism, or PCAM, which is a retrospective true-up mechanism that ensures, over time, customers pay the actual cost of the power they use.

Q. How does the total-company NPC forecast relate to the PCAM?

A. Here is the PCAM process, step-by-step: First, the Commission approves customer rates for the upcoming year based on our *forecasted* NPC. This is our best estimate of future costs and is determined based on *forecasting* total-company NPC and then allocating a portion of the total-company NPC to Washington. Second, throughout that year, the Company operates the system and incurs *actual* NPC based on real-world conditions like weather and market prices. Third, after the year is over, the PCAM process requires us to compare the initial forecast to the actual results. Crucially, the very same spreadsheet allocation method is applied to both the forecast numbers and the actual numbers.

If our initial total-company forecast was inaccurate, the actual total-company costs will inevitably be very different. This creates a mismatch, or a deferral balance, between the amount that customers paid in their rates and the amount that the power

[3] Mullins, Exh. BGM-1CT at 17:15-18.

actually costs. This difference must be corrected. If our actual costs were higher than forecasted, we may collect that difference from customers in a future period. If our costs were lower, we may credit it back to them.

This leads directly to **rate volatility**—large, unpredictable swings in customer bills from one year to the next. Such volatility is very disruptive for families trying to manage a household budget and for businesses trying to plan their expenses. One of our primary goals in forecasting is to be as accurate as possible to minimize these swings and provide customers with stable, predictable bills. AWEC's position, by dismissing the need for an accurate forecast, would lead directly and unavoidably to greater rate volatility for Washington customers.

Q. Is an accurate total-company forecast also critical to ensuring that Washington rates are consistent with principles of cost causation?

A. Yes. Cost causation is a bedrock principle of fair utility regulation. In its simplest terms, it means that customers should only pay for the costs they cause the utility to incur. Similarly, customers should receive the financial benefits from the parts of the system that serve them.[4] It is a principle of fairness.

In a large, complex, and physically interconnected power system like PacifiCorp's, costs and benefits are not always direct or obvious. For example, a power plant located in Wyoming provides a stability benefit that helps a wind farm in Washington operate reliably. That is an indirect benefit. The total-company production cost model—the Aurora model—is the only tool we have that is capable of seeing and accurately quantifying these complex, indirect interactions across the

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[4] *See, e.g.*, Wilson, Exh. JDW-1T at 11:3-4 ("PacifiCorp has generally demonstrated that the proposed changes more closely align the costs based on causation and provides benefits to Washington customers.").

entire system. It models the physical reality of the grid, where the action of a resource located in one state has ripple effects across resources and customers in all the others.

AWEC's proposal to disregard the accuracy of the total-company model and focus only on a narrow slice of resources is a direct violation of the cost causation principle.[5] It attempts to isolate Washington in an accounting sense, pretending these critical system-wide interactions do not exist. This would lead to a situation where Washington customers might receive benefits, such as grid stability, from the broader system, for which the associated costs are not properly recognized or measured. To say that the accuracy of the total-company NPC forecast is "not necessarily at issue"[6] implies an intent to seek benefits without recognition of commensurate costs. An accurate, total-company forecast is the only way to ensure the cost causation principle is honored, ensuring Washington customers pay their fair share of the integrated system that serves them.

iii. Integrated Portfolio: Why Resources in Other States Benefit Washington

Q. AWEC also stated that Washington should not be concerned with power plants, such as coal and gas plants in other states, that are not directly part of Washington's state allocation.[7] From your expert perspective, is this a valid point?

A. No. AWEC's view reflects a fundamental misunderstanding of how a modern, interconnected power grid functions. The electric grid is not a collection of separate islands. It is a single, massive, interconnected machine that spans across the entire

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[5] Mullins, Exh. BGM-1CT at 17:13-18:4.
[6] Mullins, Exh. BGM-1CT at 17:17-18.
[7] Mullins, Exh. BGM-1CT at 17:20-21.

western half of the country.

The flow of electricity is governed by the laws of physics, not by state lines or allocation methodologies. Electricity follows the path of least resistance across the entire network of transmission lines. An event in Utah or Wyoming—such as a large power plant turning on or off—can and does have an instantaneous effect on the stability and reliability of the power being delivered to homes and businesses in Washington. AWEC's position that "Washington is not concerned . . . with the cost of PacifiCorp's coal and gas plants allocated to other states" attempts to draw an artificial accounting wall around Washington that simply does not exist in the physical world.[8] For our forecast to be accurate and useful, it must model the physical reality of this interconnected system.

Q. Can you explain how these other plants benefit Washington customers even though Washington rates do not include the capital costs of these plants?

A. Yes. Washington's portfolio of allocated power plants includes a significant amount of renewable resources like wind, solar, and run-of-river hydropower. However, the portfolio of resources that Washington customers pay for directly does not include enough dispatchable generation—that is, power plants that we can turn on and off or ramp up or down as needed—to fully support and integrate those renewable resources.

The coal and gas plants located in other parts of our system, particularly in PacifiCorp East (PACE) (i.e., PacifiCorp's eastern balancing authority area), provide this essential support service. And they provide it **at no direct cost to Washington**

[8] Mullins, Exh. BGM-1CT at 17:20-21.

customers. This means that Washington customers do not pay for the construction or the fixed maintenance costs of these specific plants in other states even though these resources undoubtedly provide critical ancillary services that enable the operation of resources Washington does pay for.

A useful analogy is to imagine you own an electric car, which represents Washington's renewable resources. Your neighbor owns a large, reliable backup generator. You do not pay for your neighbor's generator or its upkeep. However, your neighbor generously allows you to plug into their generator for free whenever your car's battery is low or when you need an extra boost. This is a massive benefit that you would otherwise have to pay for yourself by installing your own expensive backup system. The dispatchable plants in PACE are like that neighbor's generator for Washington's renewable portfolio. Ignoring these resources in our forecast, as AWEC's position implies, is like pretending that free backup generator does not exist. It is an attempt to seek benefits without recognition of commensurate costs.

Q. Can you explain in greater detail how the Company's dispatchable resources that are not allocated to Washington nonetheless enable the operation of renewable resources that are allocated to Washington?

A. Yes. Renewable resources like wind and solar are intermittent or variable, i.e., they only produce power when the wind is blowing or the sun is shining. This output can change dramatically from one minute to the next. However, the electric grid requires a perfect, instantaneous balance between the amount of electricity being generated (supply) and the amount customers are using (demand).

To ensure this instantaneous balance, utilities like the Company are required to carry "Regulation Reserves," which are dispatchable power plants—like natural gas plants—that are kept online and running at less than full power. These plants stand ready to instantly increase or decrease their output to counteract, or balance, the fluctuations from wind and solar resources. They are the shock absorbers of the grid.

Imagine you are driving a car on a very windy day. The gusts of wind represent the variable output of renewable resources, pushing your car from side to side. To stay safely in your lane, you must make constant, small adjustments to the steering wheel. Those steering adjustments are the regulation reserves provided by dispatchable power plants. Without them, the grid would become unstable, leading to potential power quality issues or even outages.

The dispatchable coal and gas plants across our entire system, including those in PACE, provide these critical "steering adjustments" that allow us to reliably integrate Washington's share of renewable resources. The Aurora model is essential because it captures these system-wide physical interactions, modeling how holding these reserves on plants in one area affects the dispatch of all other resources and market transactions across the system.

On a related note, the WEIM benefits embedded in the NPC forecast as a reduction to NPC are primarily driven by energy imbalances on dispatchable, participating plants, which include the very same coal and gas resources that "Washington is not concerned" with.[9]

[9] Mullins, Exh. BGM-1CT at 17:20-21.

Q. What would be the practical consequence for Washington's power supply and costs if we were to ignore those non-Washington plants in the forecast, as AWEC's position implies?[10]

A. Washington rates would increase. First, the NPC forecast would be inaccurate because it would be modeling a world where Washington's intermittent renewable resources are perfectly stable and self-sufficient, which is physically impossible. This would grossly understate the true cost of reliably serving Washington customers, because it would ignore the very real need for regulation reserves and the market purchases required in the real world to balance the system second-by-second. The alternative would be to model the all-in costs of dedicated Washington-only dispatchable generation resources that would be assigned and paid for exclusively by Washington customers. This alternative would undoubtedly increase Washington rates relative to the status quo where Washington customers receive the benefits of dispatchable generation that is not included in Washington rates.

Second, this deep inaccuracy would flow directly into the PCAM process. When the flawed forecast is eventually compared to the actual, real-world costs, there would be a massive and unexpected shortfall. This would have to be recovered from customers, resulting in a large and sudden bill increase—the exact rate volatility we strive to avoid.

Finally, it would fundamentally violate the principle of cost causation. It would allow the forecast to pretend that Washington is an island, enjoying the stability benefits of the integrated system in the real world while ignoring the

[10] Mullins, Exh. BGM-1CT at 17:20-21.

existence of the very resources that provide those benefits. This is not a sound basis for setting fair and reasonable rates.

iv. Rejecting a Flawed and Costly Approach

Q. Based on everything you have explained, what is the fundamental flaw in AWEC's recommendation that the Commission evaluate the forecast by looking only at Washington's specific resources in isolation?

A. The fundamental flaw in AWEC's entire position is that it is disconnected from reality—both financial reality and physical reality. Their recommendation is built upon three core disqualifying errors.

First, it is based on a factual error about the process. AWEC incorrectly claims that the allocation spreadsheet is a forecasting tool.[11] As we have discussed, this is wrong. The complex forecasting is done by the Aurora simulation model for the entire system, and the spreadsheet merely allocates those results. This initial error invalidates their subsequent conclusions.

Second, it ignores physical reality. AWEC's position asks the Commission to pretend that Washington is an electrical island. This ignores the immutable laws of physics that govern the interconnected grid. It willfully disregards the massive and tangible stability benefits that Washington customers receive from being part of an integrated system—benefits provided by resources in other states for which Washington customers pay no capital costs.

Third, it invites financial harm to customers. By dismissing the need for an accurate system-wide forecast, AWEC's position guarantees future rate volatility.

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[11] Mullins, Exh. BGM-1CT at 17:15-18.

The PCAM process is designed such that any inaccuracies in the forecast should eventually be reconciled over the long term. A deliberately incomplete and therefore inaccurate forecast, as AWEC's position would create, will lead directly to large, unpredictable bill swings for the very customers AWEC claims to protect.

Q. To be perfectly clear, if the Commission were to adopt the viewpoint presented by AWEC, what would be the most likely consequences for the ratepayers of Washington?

A. The consequences would be direct, negative, and unavoidable. First, Washington customers would have **inaccurate rates**. The initial rates set by the Commission would not reflect the true cost of serving them, because those rates would be based on a flawed forecast that ignores critical operational realities of the power grid.

Second, customers would face **guaranteed rate volatility**. It is not a question of "if," but "when and how much." The PCAM mechanism will eventually true-up the difference between the inaccurate forecast and the actual costs incurred. This will result in large, disruptive, and unpredictable surcharges or credits on customer bills in subsequent years, making it difficult for families and businesses to budget for their essential electricity service.

Third, it would represent a **violation of the principle of fairness**, or cost causation. It would create a regulatory framework where Washington customers receive valuable system benefits in the real world, but the process for setting their rates pretends those benefits and the resources that provide them do not exist. This is the opposite of transparent, reality-based ratemaking.

Q. Therefore, what is the Company's final recommendation on how the Commission should view the total-company NPC forecast and its critical relationship to the costs ultimately allocated to Washington?

A. The Company's recommendation is that the Commission must reject AWEC's flawed and misleading position in its entirety. The Commission should recognize that an accurate, system-wide NPC forecast, produced by a sophisticated production cost model like Aurora that simulates the entire interconnected grid, is the indispensable foundation for determining just and reasonable rates for Washington. It is not an optional or irrelevant piece of the puzzle; it is the cornerstone upon which fair and stable rates are built.

Adopting the Company's comprehensive, reality-based approach is the only way to honor the principle of cost causation. It is the only way to ensure the stability and predictability of customer bills. And it is the only way to set rates that are grounded in the physical and economic realities of operating a modern, integrated power system to reliably serve the citizens of Washington. We urge the Commission to affirm the critical importance of an accurate total-company forecast.

2. <u>AWEC – Aurora Version Update</u>

Q. AWEC points out that it used a new version of Aurora that differs from the one used by the Company in its initial filing and that using AWEC's new version increases the NPC forecast.[12] Do you agree with AWEC that rates should be set using the new version of Aurora?

A. Not necessarily. As an initial matter, the new version of Aurora is not a simple update to the model, which has been an issue in prior power cost filings. Rather, AWEC used Aurora version 16, while the Company uses Aurora version 15. An update to the major model version of a complex simulation tool like the Aurora model is not a

[12] Mullins, Exh. BGM-1CT at 21:2-16.

minor bug fix; it is a substantive and material change to the analytical engine itself. It is more akin to replacing the entire engine in a car rather than just updating its navigation software.

Each new major version of Aurora can, and often does, contain significant changes to its core logic, its mathematical algorithms, and its underlying features. For example, the release notes for Aurora version 16 detail numerous substantive enhancements, such as entirely new methods for calculating a resource's contribution to reliability and new constraints for how different types of fuel can be blended.[13]

These are not cosmetic changes; they fundamentally alter how the model arrives at its conclusions. Using a new version can produce a different NPC forecast even if every single data input—like fuel prices and demand forecasts—were to remain exactly the same. While the Company does not oppose updating to Aurora version 16 in its next filing, it has consistently used the same version (15 in this case) throughout an individual case to ensure consistency and recommends doing so here.

3. <u>STAFF – Forward Market Transaction Modeling Adjustment</u>

i. Introduction to the Modeling Adjustment

Q. By way of background, please explain "hedge costs" or "forward market transaction costs."

A. A major part of the Company's job is to protect customers from sudden spikes in the price of electricity. We do this through a process called hedging, which works much like insurance. We enter into contracts (or hedges) to buy power in the future at a set price, which protects customers from price volatility.

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[13] Energy Exemplar, *Aurora 16.0 Release Notes*, May 2025 (available at https://aurora.energyexemplar.com/welcome/customer_support/docs/Release_Notes_v16.0.pdf).

Q. What modeling change does the Company recommend for its hedge costs?

A. To reflect the fact that the Company will eventually need to hedge each quarter at a minimum average of 75 percent, the Company modeled additional short-term firm transactions, in quarterly 25 megawatt energy blocks of heavy or light load hour products, and loaded into the model to ensure that the quarterly average hedge ratio in the peak hour of each month satisfies the policy-dictated minimum requirements for the first quarter.

Q. Why does the Company recommend this modeling improvement?

A. As previously mentioned, we use Aurora to forecast NPC. The issue we are discussing, and the reason for our proposed modeling adjustment, arises from a key difference between the computer simulation and the real world. The Aurora model operates with "perfect foresight," meaning it knows exactly what the supply and demand and price for electricity will be for every single hour of the year. In the real world, of course, we do not have a crystal ball. This is precisely why we hedge—to manage the risks of an uncertain future.

Furthermore, in the real world, these hedges (or forward market transactions) are not bought for single, specific hours. The forward market sells electricity in standardized, large blocks, typically for an entire season, or quarter, at a time. This is a crucial point. If we need extra power for just a few hot summer afternoons, we cannot just buy power for those specific hours a year in advance. We must buy a standardized block of power that covers the entire summer quarter, and then we must sell back the energy we do not need in the markets closer to the delivery day, such as in the day-ahead market. This process of buying a large block and selling back the unneeded portions incurs a real, unavoidable transaction cost. The Aurora model, with its perfect foresight, does not capture this real-world transaction cost because it can perfectly buy only what it needs for each exact hour.

Our proposed modeling adjustment simply accounts for this real-world cost. It ensures that the forecast of forward market transactions inside the Aurora model reflects the way **energy is procured for** forward market transactions in the real world, and reflects the way this impacts the actual, incurred NPC. By doing so we make the overall NPC forecast more accurate. Even Commission Staff acknowledges that a gap exists between the perfect forecast from Aurora and a more realistic expectation of hedging costs.[14] Our proposal is the reasonable and necessary step to close that gap.

[14] Wilson, Exh. JDW-1T at 42:5-8.

ii. The Reality and Forecasting of Forward Market Transactions

Q. Staff's testimony seems to suggest these forecasted hedges are not real; Staff states that "PacifiCorp does not actually intend to purchase these energy blocks"[15] and that your proposal is essentially a "tracking mechanism" [16] to collect money from customers for costs that have not happened yet. How do you respond?

A. That characterization by Staff is misleading. A forecast, by its very definition, is an estimate of future events and costs. The entire NPC forecast is a projection of the millions of transactions that will be required to serve customer load in the 2026 test period. No single forecast market transaction within our entire NPC forecast is a specific purchase that we "actually intend" to complete in the exact manner modeled.

To illustrate Staff's inconsistency, let us consider another type of market purchase included in our forecast referred to as "system balancing transactions." These are the millions of smaller energy purchases and sales the Aurora model projects we will need to make in the day-ahead and real-time markets to keep the grid in perfect balance. The Company does not "actually intend" to purchase those specific hourly energy blocks either; they are a model-based representation of possible future transactions, identical in nature to the forecasted forward market transactions. In our forecast, we projected 4.6 million megawatt-hours (MWh) of these system balancing purchases. Staff has raised no objection to including the costs of these projected transactions in rates. Yet Staff singles out the 3.6 million MWh of projected forward market transactions (i.e., hedges), and dismisses them using the

[15] Wilson, Exh. JDW-1T at 41:11.
[16] Wilson, Exh. JDW-1T at 43:4-6.

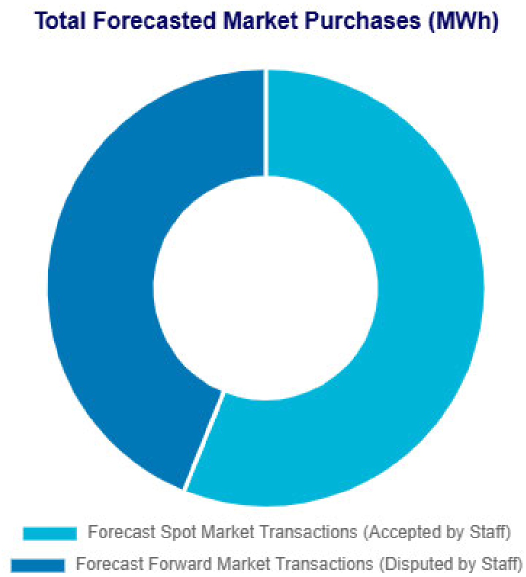
exact same logic that should, if applied consistently, cause them to reject the system balancing transactions as well. This selective criticism is illogical and reveals a bias in their analysis.

Furthermore, the claim that our proposal is a "tracking mechanism" is equally baseless. If forecasting the cost of forward market transactions, before the actual costs are incurred, constitutes a "tracking mechanism," then the entire NPC forecast also must be considered a "tracking mechanism," because nearly every component—from fuel costs to wheeling costs to system balancing purchases—is an estimated cost that will be embedded into rates before the actual costs are incurred. This is the standard, Commission-approved process for setting rates based on a forward-looking test year.

Finally, these hedges are far from hypothetical in practice. They are a core part of our real-world operations to protect customers. To provide context, in calendar year 2024, the Company executed 3.0 million MWh of these forward market purchases, and in 2023, we executed 3.4 million MWh. The volume we have forecasted is entirely consistent with our actual, historical forward market transactions. Staff's attempt to portray these as phantom transactions that may not occur is directly contradicted by the facts of our operations.

Consistency in Forecasting

Staff's objection to forecasted forward market purchases (e.g., hedges) as "not transactions that PacifiCorp specifically anticipates completing" is inconsistent. The Net Power Cost (NPC) forecast is inherently a collection of reasonable, model-driven forecasts, including forecasted day-ahead / real-time market purchases which Staff accepts, and are also "not transactions that PacifiCorp specifically anticipates completing". Both are calculated projections necessary for an accurate forecast.



Q. Staff claims that the 25 megawatt block size you used in the model is "arbitrary."[17] Can you please explain why you chose that specific size?

A. The selection of a 25 megawatt, or MW, block size is the opposite of arbitrary; it is a direct reflection of a fundamental standard in the western electricity markets. In the forward markets where utilities like the Company purchase power months or years in advance, electricity is traded in standardized products to ensure liquidity and efficiency. The standard products is a 25 MW block of power delivered for a specified number of hours over an entire quarter.

To use a simple analogy, when you go to the store to buy eggs, you purchase them in a carton of a dozen. You do not buy two eggs or seven eggs. The dozen is the

[17] Wilson, Exh. JDW-1T at 43:1-2.

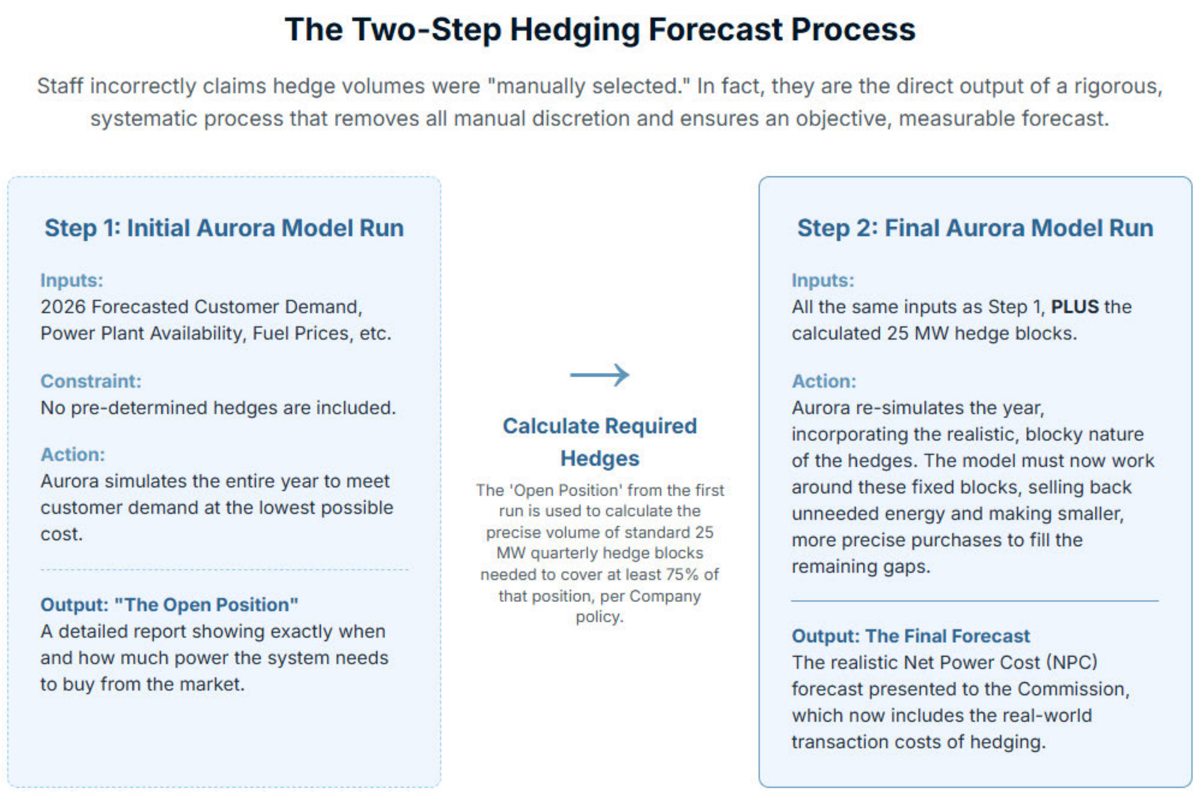
standard unit of commerce. Similarly, in the forward electricity markets, 25 MW is the standard unit of commerce. This is not a convention created by the Company; it is an established industry-wide practice for bilateral market transactions in the West. By modeling our hedges in 25 MW increments, we are not making an arbitrary choice; we are ensuring our forecast accurately reflects the realistic constraints and practices of the market in which we must operate to secure power for our customers. Staff's characterization of this as "arbitrary" demonstrates a lack of familiarity with the basic mechanics of forward energy trading.

iii. The Process for Determining Forward Market Transaction Volumes

Q. Staff also alleges that the Company "manually selected"[18] the amount, or volume, of these hedges, implying the decision was not based on a rigorous analysis. Could you please walk through the exact process you used to determine the volume of hedges to include in the forecast?

A. The assertion that these volumes were "manually selected" is factually incorrect. The amount of hedges included in our final forecast was determined through a systematic, data-driven, two-step modeling process that is both rigorous and logical. It is a purely analytical process that removes any sort of manual discretion or arbitrary selection. To help explain this, it may be useful to visualize the process.

[18] Wilson, Exh. JDW-1T at 45:4-5.



As this illustration shows, the process begins with an initial run of the Aurora model. In this first run, we do not include any of the forecasted hedges in question. The model simply determines the most economically efficient way to serve our customers' forecasted energy needs for 2026. The output of this run tells us the Company's "open position," which is the amount of energy we are short and will need to acquire from the market to meet our reliability and risk management obligations.

This is the critical step. The output from that first model run becomes the input for the second model run. We take that calculated "open position" and determine the precise number of standard, 25 MW quarterly hedge blocks required to cover that position up to the 75 percent minimum level mandated by our energy risk management policy. This calculation is performed methodically in our supporting workpapers.

Finally, we conduct a second and final Aurora model run. In this run, we include the quarterly hedge blocks that were calculated from the first run's output. The model then re-optimizes the entire system, accounting for these more realistic, block-shaped market purchases. This final run produces the NPC forecast that we have filed. The hedge volumes are a direct output of a preceding model run and a subsequent analytical calculation. They are the very definition of a modeled result, not a "manual selection" as Staff incorrectly claims.

iv. Validity of the Official Forward Price Curve

Q. Staff claims that you "manually priced" these hedges using the Official Forward Price Curve (OFPC), and that this price is not a valid forecast of what will actually be paid.[19] Can you explain what the OFPC is and why it was the correct price to use?

A. Yes. Staff's assertion is incorrect on both counts. The hedges were not "manually priced" in the sense Staff implies, and the OFPC is absolutely a forecast of the price at which market transactions are expected to occur.

First, the OFPC. The OFPC reflects future electricity and natural gas prices. For the near term, which includes the 2026 test period we are discussing, the OFPC is based directly on actual, observable prices from the forward energy markets—the same markets where we execute our forward market transactions. In this way, the OFPC is more than just an objective, market-based forecast; it is the actual price the Company could pay today for the delivery of energy next year. By using actual

[19] Wilson, Exh. JDW-1T at 45:4-5.

market forward prices, the OFPC is not a Company internal forecast; it is a standard, transparent, and market-based price source that is foundational to our entire NPC forecast.

Now, to address Staff's claim, it is critically important to understand that we use the OFPC to price nearly *all* forecasted market-based components in our NPC filing. This includes the 4.6 million MWh of system balancing transactions that Staff raises no objection to. It also includes the price for our natural gas hedges and many of our power purchase agreements. The process of applying the OFPC to a modeled transaction is not "manually pricing"; it is the standard and appropriate methodology for valuing future energy transactions in a forecast.

Staff's argument is logically inconsistent. They accept the use of the OFPC as a valid price forecast for billions of dollars worth of other projected costs in the NPC forecast while simultaneously claiming it is not a valid price forecast for our projected forward market transaction costs. If the OFPC is an invalid price source, then the Commission would have to reject our entire NPC forecast, not just this one component. The simple fact is that the OFPC is both the as-filed market forward price *and* it reflects the price that market transactions are expected to be transacted at. Staff's attempt to separate these two inseparable concepts is factually wrong and serves only to create confusion. We used the OFPC for these forward market transactions because it is the correct, consistent, and Commission-accepted price forecast for this purpose.

Q. Staff's testimony makes a very strong claim that "PacifiCorp has not validated this model against historical transaction data or provided any other evidence supporting this cost."[20] Is Staff correct?

A. No, that claim is inaccurate. We provided Staff with a vast and comprehensive body of evidence that directly supports and validates this specific modeling adjustment. First, we submitted thirteen pages of detailed testimony dedicated to explaining our hedging practices, the risks they mitigate, and how they are modeled. This can be found in Exhibit RJM-1CT, Section VI, which then directs the reader to Exhibit No. RJM-1CT, Section IX, subsection C, as well as Exhibit No. MGW-1CT, Section III. These testimonies provide the complete context and justification for our approach.

Second, we provided voluminous supporting workpapers. This included 34.6 megabytes of model input Excel files and 58.7 megabytes of model output Excel files. These files were explicitly named to leave no room for confusion.[21] These workpapers show, in painstaking, formula-driven detail, exactly how the Company's energy and capacity needs were derived from the initial Aurora run and how those needs were then translated into the 25 MW quarterly hedge blocks for the final run. It is standard regulatory practice to provide complex calculations in supporting workpapers, as it is impossible to embed multiple, formulaic spreadsheets into a testimony document. To claim there is "no evidence" when these detailed supporting workpapers were provided is to fundamentally misunderstand the nature of NPC forecasting. If these workpapers are "no evidence," then no NPC forecast could ever

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[20] Wilson, Exh. JDW-1T at 42:9-10.

[21] *See, e.g.*, NEW-PAC-RJM-GNPrehedgingforWA-4-1-2025 (C); NEW-PAC-RJM-GNPrehedgingforSysWA-4-1-25 (C).xlsx; NEW-PAC-RJM-GNPrehedgingPeak-4-1-25 (C).

be justified. Additionally, the Company responded to a number of data requests initiated by Staff that addressed and clarified the drivers of these costs.

Third, and most definitively, we directly addressed Staff's claim about model validation. We performed what is known as a benchmarking study, sometimes called a "backcast," for the year 2020 and submitted it as Exhibit RJM-5C. A backcast is a powerful way to validate a model's accuracy. We essentially used our current Aurora model to "forecast" the past. We fed the model the actual conditions from 2020—actual customer demand, actual fuel prices, actual weather—and then compared the model's forecasted NPC with the actual, historical NPC that we recorded for that year.

The results of this 2020 benchmarking study, which—and this is the most critical point—*included* the modeling of quarterly block, 25 MW increment, hedging transactions, demonstrated that our model is both reasonable and accurate. The study concluded—as quoted from the exhibit provided to Staff: "The results of the benchmarking study show that Aurora simulated [total-company] 2020 historical net power costs (NPC) at $58.7 million less than [total-company] actual NPC."[22] On a multi-billion dollar system, this small variance confirms that the model, as structured by the Company, inclusive of forward market transactions in quarterly blocks of energy, in increments of 25 MW, provides a reasonably accurate forecast of reality. Staff's claim that we have not validated the model against historical data is contradicted by the record; we provided them with the very study that does exactly that.

[22] Mitchell, Exh. RJM-5C at 1.

v. Accounting for the Washington-Specific Hedge Book

Q. The Company is proposing to manage a separate "Washington-Specific Book" for hedges, and all forward market transactions. Staff claims your forward market transaction cost forecast does not take the impact of this Washington-Specific Book into account.[23] Can you please address this concern?

A. Yes. This is another claim from Staff that is directly contradicted by the evidence we filed. The assertion that we failed to account for the Washington-Specific Book is unequivocally false. We not only accounted for it, but we also provided Staff with the specific model outputs and supporting workpapers that explicitly detail the Washington-only hedges.

If you refer to Exhibit RJM-2, on page 4, which is a detailed report of the Washington-allocated NPC forecast, you will find a line item labeled "Pre-Hedging Transactions WA." This line item represents the forecasted Washington-specific forward market purchases—the very hedges we are discussing—that are calculated for and assigned to the simulated Washington-Specific Book. The costs and energy volumes associated with the non- Washington-Specific Book are separately calculated and are excluded from the Washington NPC forecast. The very structure of our filing separates these two books.

Furthermore, this separation was not just a summary-level adjustment. The underlying analysis was incredibly detailed. We provided Staff with numerous supporting Excel workpapers that were explicitly named to leave no room for confusion. For example, workpapers with titles like "NEW-PAC-RJM-

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[23] Wilson, Exh. JDW-1T at 43:19-21.

GNPrehedgingforWA-4-1-2025 (C).xlsx," "NEW-PAC-RJM-GNPrehedgingforSysWA-4-1-25 (C).xlsx," "NEW-PAC-RJM-GNPrehedgingPeak-4-1-25 (C).xlsx" were provided as part of our filing. These files, and others like them, contain the granular, source calculations for the Washington-Specific Book.

The entire modeling framework, as described in the direct testimony of at least two of the Company witnesses, is built around the necessity of creating and managing two separate power and gas hedge books—one for Washington and one for the rest of the system. The existence of the "Pre-Hedging Transactions WA" line item in the primary NPC exhibit, supported by dedicated testimony and multiple, clearly-labeled workpapers, is irrefutable proof that Staff's claim is incorrect. We can only conclude that Staff did not review this information.

Q. Staff argues that your proposed hedging cost does not meet the Commission's standard for being a "known and measurable" cost.[24] Could you first explain in simple terms what that standard means, and then explain how your proposal satisfies it?

A. Absolutely. The "known and measurable" standard is a cornerstone of ratemaking that ensures fairness and predictability for customers. In simple terms, it means that if we are going to adjust our historical costs to forecast the costs for a future rate period, that adjustment must be for an event that is reasonably certain to happen—that is the "known" part—and the cost of that event must be calculated with a reasonable degree of accuracy, not just a wild guess—that is the "measurable" part.

The Commission has long recognized that forecasting future power costs is

[24] Wilson, Exh. JDW-1T at 43:25-45:8.

complex and cannot be done with perfect certainty. Therefore, the Commission has established that for power costs, the "known and measurable" standard is met if the costs are the result of a simulation model, like Aurora, provided that the inputs to that model are reasonable.[25] Our proposal fits squarely within this established precedent.

Let us break it down: First, is the event "known"? Yes. The event is the need to execute forward market transactions to manage price and supply risk for customers. This is not optional; it is a requirement of energy risk management policy. This is a continuous and certain operational activity.

Second, is the cost "measurable"? Yes. As Staff themselves note, modeled results are acceptable if the inputs are reasonable.[26] Our cost is not, as Staff claims, based on "manually selected" amounts or "manually priced" values.[27] As we have already explained, the *volume* of the hedges is measured through a rigorous two-step Aurora modeling process. The *price* of the hedges is measured by applying the OFPC, which is the Commission-accepted, market-based price forecast used for virtually all other modeled market.

Therefore, our proposed hedging cost is a modeled power cost result, derived from reasonable, systematic, and well-documented inputs. It is not an arbitrary estimate or a simple projection. It fully complies with both the letter and the spirit of the Commission's "known and measurable" standard as it has been consistently applied to power cost forecasting. Staff's attempt to apply a different, more rigid

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[25] *See Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket Nos. UE-090134, UG-090135 & UG-060518, Order 10 at ¶ 49 (Dec. 22, 2009) ("While [power cost] models employ assumptions, estimates, and forecasts as inputs, the modeled results are generally acceptable if the model inputs are reasonable and the modeling is comparable in analytical rigor to what is brought to bear in making normalizing adjustments.").
[26] Wilson, Exh. JDW-1T at 44:18-45:3.
[27] Wilson, Exh. JDW-1T at 45:4-7.

standard to this single component of the NPC forecast, while ignoring the modeled nature of all other components, is inconsistent and improper.

vi. Flaws in Staff's "Net Transaction" Recommendation

Q. Staff recommends that the Commission reject your proposal and instead use what they call "Aurora-generated market volumes and prices."[28] They argue this is a better approach because it reflects "net transactions" and the model's "best estimate of future prices."[29] What is your response to Staff's specific recommendation?

A. Staff's recommendation is fundamentally flawed and is based on a critical misunderstanding of both how our model works and the basic principles of commodity markets. If the Commission were to adopt Staff's recommendation, it would knowingly approve a less accurate forecast that understates the real costs our customers will face.

There are two fatal flaws in Staff's proposal. The first flaw relates to price. Staff recommends using "Aurora-generated market prices" because they believe it reflects the model's "best estimate of future prices."[30] This is factually incorrect. The Company does not use the Aurora model as a price forecasting tool. Instead, we *input* the OFPC *into* the model to serve as the price forecast. Staff is recommending we use a model function that we do not use, to replace a market-based price forecast that is used consistently across the entire NPC model. Their recommendation is based on a false premise about our modeling practices.

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[28] Wilson, Exh. JDW-1T at 45:12-14.
[29] Wilson, Exh. JDW-1T at 45:15-20.
[30] Wilson, Exh. JDW-1T at 45:15-20.

The second, and more significant, flaw relates to Staff's idea of using "net transactions." Staff argues that using Aurora's net purchases and sales is reasonable.[31] This logic completely ignores the very real-world cost that our modeling adjustment is designed to capture: the cost of market friction, best exemplified by the concept of the bid-ask spread. Presented below is a clear analogy to explain this crucial concept.

Imagine you need to buy apples for your family for the next three months, and to get a good, stable price, you go to a wholesale farmer's market. However, the farmer only sells apples by the full crate, and each crate contains far more apples than your family can eat. You only need a dozen apples a week, but to get the benefit of that stable wholesale price, you must buy the whole crate. So, you buy the crate. You take the dozen apples you need for the week, and then you take the rest of the apples you do not need and sell them back to a local grocer. The grocer, who needs to cover their own costs and make a profit, naturally will buy them from you for a little less than what you paid the farmer. That small difference, that loss you take on the apples you had to sell back, is a real, out-of-pocket cost you incurred just to get the dozen apples you actually needed. At the end of the day, you end up "net zero" in volume, with exactly the 12 apples that you require. However, being "net zero" in volume does not leave you "net zero" in costs.

This is exactly the type of cost we are modeling with the forward market transaction modeling adjustment. The cost is not because the price of apples changed; it is because you were forced to buy in a block (a crate) and then sell the excess (individual apples) back to the market at a lower price.

[31] Wilson, Exh. JDW-1T at 45:15-16.

Staff's proposal to use Aurora's "net transactions" is equivalent to saying the person in our analogy spent nothing because their net position in apples is zero. But the transaction had a very real cost that was incurred. By recommending this approach, Staff is proposing to ignore the very real transaction costs that our adjustment is designed to measure. Ironically, Staff's testimony begins by acknowledging there is a "gap between the perfect forecast created by Aurora . . . and a more realistic expectation for the impact of hedging transactions[.]"[32] Yet their final recommendation is to use a method that guarantees this gap will persist, ensuring the forecast remains unrealistic. Their position is internally contradictory and logically unsound.

Q. Could you please summarize for the record why the Commission should reject Staff's recommendations and approve the Company's proposal for modeling future hedging costs?

A. The Commission should reject Staff's recommendations and approve the Company's proposal for one central reason: our proposal leads to a more accurate and realistic forecast of the costs to serve Washington customers, while Staff's position is based on a series of factual and logical errors that would result in an inaccurate and understated forecast. To summarize our key points:

First, the Company's modeling adjustment is a necessary and reasonable step to close a recognized gap between a perfect computer simulation and messy, real-world market operations. It correctly captures the unavoidable transaction costs associated with purchasing standardized, quarterly blocks of power to hedge against

[32] Wilson, Exh. JDW-1T at 42:6-8.

price volatility or manage supply risk, a practice essential for protecting customers.

Second, Staff's entire opposition is built on a foundation of falsehoods. They incorrectly claim our methods are "arbitrary" when they are based on industry standards. They incorrectly claim our volumes are "manually selected" when they are the product of a rigorous, two-step modeling process. They incorrectly claim our pricing is improper when it uses the same Commission-accepted price forecast applied to the rest of the model. And they incorrectly claim we provided "no evidence" when we provided volumes of detailed testimony, workpapers, and a comprehensive model validation study.

Third, our approach is fully compliant with all regulatory requirements. We have demonstrated that our forecast properly accounts for the separate Washington-Specific Book, and that our methodology for calculating this cost fully satisfies the Commission's established "known and measurable" standard for modeled power costs.

Finally, Staff's proposed alternative is unworkable and would harm customers. It is based on a false premise about how our model calculates prices and a logically flawed "net transaction" theory that ignores the real costs of market friction. Adopting Staff's recommendation would be a step backward, leading to rates based on a less accurate forecast.

For these reasons, we respectfully and strongly urge the Commission to reject Staff's testimony on this matter and to affirm that the Company's modeling of forward market transactions is prudent, reasonable, and necessary for establishing just and reasonable rates.

4. AWEC – Forward Market Transaction Modeling Adjustment

i. Defining the Markets and the Core Disagreement

Q. To provide further context for issues parties have raised relating to the Company's modeling of forward market transactions, could you please explain, in more detail, the different ways an electric utility like the Company buys and sells power?

A. Certainly. You can think of the electricity market as operating on three distinct timelines, each serving a different purpose.

First, there is the **Forward Market**. This is our long-term planning horizon. In this market, we make transactions anywhere from one and a half years down to about three months before the electricity is actually needed. The purpose here is to manage risk. It is very much like booking an airline ticket several months in advance of a trip. You do this to lock in a price you find acceptable or, more importantly, to guarantee you have a seat on the plane. You are hedging against the risk that prices might skyrocket closer to your travel date or that the flight might sell out entirely. In the same way, the Company uses the forward market to enter into forward market transactions to protect our customers from future price volatility and to ensure we have secured a sufficient supply of power to reliably meet their needs. This is a crucial risk management activity that provides stability and predictability for customer bills.

Second, we have the **Day-Ahead Market**. This is a much shorter-term market, focused on the very next one to three days.[33] This market represents the vast

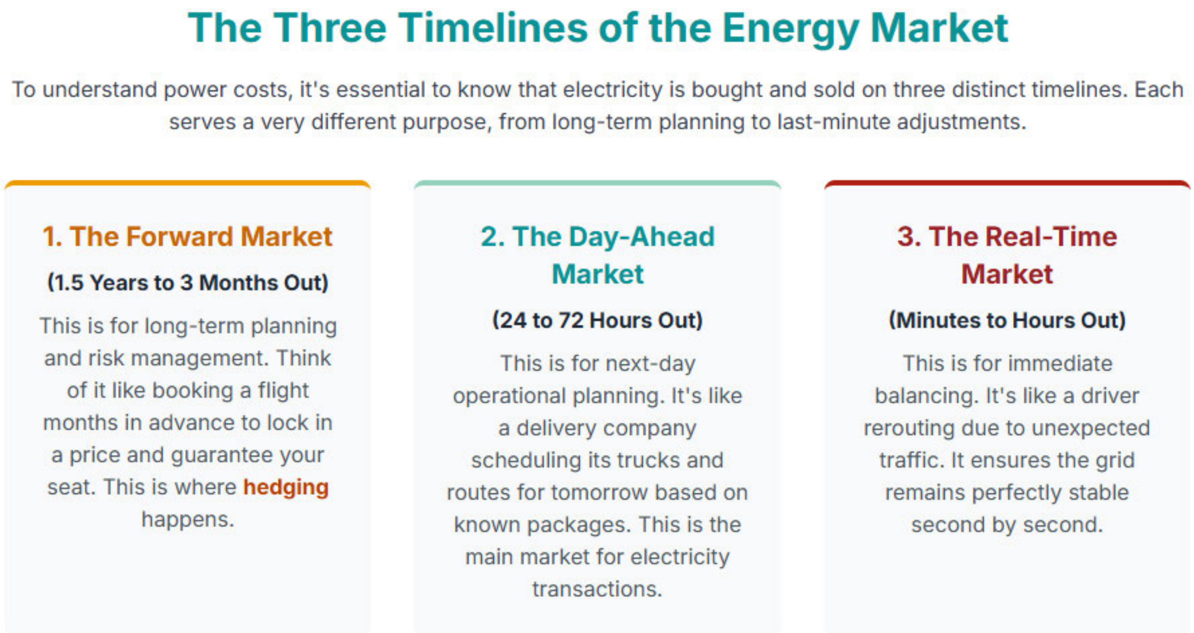
[33] Or next 2-3 days in the case of Thursday and Friday, with longer look-aheads for holiday periods.

majority of all electricity transactions. Think of it like a large-scale delivery company planning its routes for tomorrow morning. Based on all the packages it knows it needs to deliver, it schedules its trucks and drivers in the most efficient way possible. Similarly, in the day-ahead market, a utility buys or sells power for different blocks of hours for the following days. This allows the utility to create the most efficient and lowest-cost schedule to meet the forecasted electricity demand for that day.

Finally, there is the **Real-Time Market**. This market operates in the immediate day, balancing supply and demand on an hour to hour and minute-by-minute basis. This is the final balancing mechanism. To continue the delivery company analogy, this is like a driver adjusting their route in real-time because of an unexpected traffic jam or a last-minute delivery request. The day-ahead schedule is an excellent plan, but reality is never perfect. Customer demand might be slightly higher than forecasted, or a power plant might experience an unforeseen issue. The real-time market allows us to make those final, small adjustments to keep the power grid perfectly balanced, which is a physical requirement for its stable operation.

These three markets—Forward, Day-Ahead, and Real-Time—are distinct and sequential. Actions taken in the forward market are for long-term risk management, while actions in the day-ahead and real-time markets are for the operational scheduling and balancing of the grid.

To help visualize this, imagine a timeline stretching from 18 months in the future to the exact hour of electricity delivery. The “Forward Market” occupies the long stretch from 18 months out to 3 months out. The “Day-Ahead Market” is a specific point occurring day(s) before delivery. And the “Real-Time Market” covers the final few hours and minutes leading up to and during the hour of delivery.



Q. Earlier you discussed that the forward market is where hedging occurs. AWEC seems to be saying that the costs you are proposing in this new hedging adjustment are already being captured in another adjustment called the "DA/RT adjustment."[34] Is AWEC's assertion correct?

A. No, that is fundamentally incorrect. The assertion that these two adjustments capture the same cost is based on a misunderstanding—or mischaracterization—of their distinct purposes and the market timelines we just discussed. The hedging adjustment and the day-ahead/real-time, or DA/RT, adjustment are mutually exclusive; they account for different costs incurred at different times for entirely different reasons. There is absolutely no double-counting occurring.

Let us refer back to the market timeline. The new hedging adjustment, which is the subject of this discussion, is designed to capture a specific transaction cost that

[34] Mullins, Exh. BGM-1CT at 55:13-56:2.

arises when we execute **forward market** transactions, months or even years in advance of delivery. It is a cost directly related to the structure of the long-term products available for managing price and supply risk.

In contrast, the DA/RT adjustment has absolutely nothing to do with these forward market transactions. The DA/RT adjustment is a long-standing and previously approved mechanism that applies only to transactions (system balancing transactions) in the **day-ahead and real-time markets**—the short-term operational and balancing horizons, (i.e., the spot market). Its purpose is to align our modeled forecast with the realities of buying and selling power in the spot market, which occurs just hours before delivery.

To put it in simple terms, claiming these are the same cost is like saying the fee you paid to a travel agent to book a vacation package six months in advance is the same as the cost of a taxi you took from the airport upon arrival. They are separate costs, for separate services, at separate times, and it would be illogical to suggest they are the same thing. The forward market transaction is the "travel agent fee" for long-term planning, and the DA/RT adjustment relates to the "taxi fare" for on-the-spot transportation. They are completely unrelated.

The Core Dispute: One Cost or Two?

AWEC claims a cost PacifiCorp has identified is being "double-counted." This is incorrect. The two adjustments in question are for entirely different costs, incurred at different times, for different reasons.

The Hedging Adjustment

Applies to: The Forward Market

This is a new adjustment to capture the **transaction cost** of buying power in large, standardized blocks months or years in advance. It's like a fee for long-term planning and risk management.

The Day-Ahead and Real-Time (DA/RT) Adjustment

Applies to: Day-Ahead & Real-Time Markets

This is an existing, methodology. It accounts for the costs of **short-term balancing** of the grid just hours before delivery. It has nothing to do with long-term hedges.

Claiming these are the same is like saying a travel agent's booking fee is the same as a last-minute taxi fare. They are completely separate.

Q. AWEC points out that both adjustments involve 25 megawatt blocks, thereby implying a connection between the adjustments.[35] Is AWEC correct?

A. No. That is an understandable point of confusion, but it focuses on a superficial similarity while ignoring the fundamental differences in function. The fact that both forward hedges and some day-ahead transactions can occur in 25 MW increments does not mean they are the same product or that their associated costs are interchangeable. As discussed above, 25 MW block is a standard "lot size" or transaction increment in the western wholesale power markets (both forward and day-ahead and real-time). However, a 25 MW block purchased as part of a *quarterly forward market transaction* a year in advance is a fundamentally different product, serving a different purpose, than a 25 MW block purchased in the *day-ahead market* for delivery the next day(s). The former is a strategic risk management tool; the latter

[35] Mullins, Exh. BGM-1CT at 55:16-18.

is an operational balancing tool. The shared size is merely a convention of the market and does not, in any way, imply that the costs associated with these distinct transactions are being double counted. AWEC's argument attempts to create a link where none exists by focusing on this irrelevant detail.

ii. Clarifying the Evidence and Defining the Transaction Cost

Q. AWEC makes the very direct assertion that "PacifiCorp's testimony on this change is brief and not entirely clear" and that you failed to discuss or justify the volumes and pricing you assumed.[36] How do you respond to that claim?

A. That assertion is incorrect and represents a profound misunderstanding of the evidentiary record the Company has provided. As discussed above in response to a similar assertion from Staff, the Company submitted detailed, narrative testimony explaining our hedging practices, the risks they mitigate, and how they are modeled in this case,[37] and voluminous supporting workpapers.[38] The claim that we did not discuss volumes or pricing when we provided the actual, formula-driven source spreadsheets is fundamentally inaccurate.

Q. AWEC included quotes from the Company's testimony that seem to support their position. They claim your own testimony links the products used for the DA/RT adjustment to the Company's "forward position."[39] How do you respond to that?

A. This is the most critical point in understanding the flaw in AWEC's argument. The

[36] Mullins, Exh. BGM-1CT at 52:6-18.
[37] Mitchell, Exh. RJM-1CT, Sections VI and IX; Wilding, Exh. MGW-1CT, Section III.
[38] *See, e.g.*, NEW-PAC-RJM-GNPrehedgingforWA-4-1-2025 (C); NEW-PAC-RJM-GNPrehedgingforSysWA-4-1-25 (C); NEW-PAC-RJM-GNPrehedgingPeak-4-1-25 (C).
[39] Mullins, Exh. BGM-1CT at 55:13-56:2.

way in which our prior testimony has been presented by AWEC is concerning, as it relies on taking partial quotes out of their essential context. When you read the full statements as they were originally provided, they tell a story that is the complete opposite of what AWEC claims.

AWEC cites the Company as saying, "The products used to balance the Company's forward position in the wholesale market [that] are primarily available in flat 25 megawatt (MW), 16-hour or 8-hour blocks."[40] However, they conveniently omit the very next sentences in that same paragraph of our testimony. The full, original statement reads: "The products used to balance the Company's forward position in the wholesale market are primarily available in flat 25 megawatt (MW), 16-hour or 8-hour blocks. *The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from those multi-hour, flat 25 MW block products. Thus, in real world operations, the Company must continuously purchase or sell additional volumes to keep the system in balance.*"[41]

As you can see, the full context makes it clear that we were describing the need for *continuous, hourly balancing transactions*—which are, by definition, real-time market activities—to true-up our position. We were not focusing on forward market transactions.

Similarly, AWEC quotes us as saying the DA/RT adjustment was designed to "reflect the inefficiencies and associated costs of that operational practice of transacting on a monthly basis using, as an example, standard 25-MW increment, 16-

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[40] Mullins, Exh. BGM-1CT at 55:13-16 (quoting Mitchell, Exh. RJM-8 at 1:20-21).
[41] Mitchell, Exh. RJM-3CT at 1:20-2:2.

hour block products[.]"[42] Again, they omit the crucial remainder of the sentence, which was: "*rebalancing on a daily basis using standard 25-MW increment, eight-hour block products, and finally closing the remaining position on an hourly basis in real-time markets.*"[43]

Once again, the full statement explicitly references "rebalancing on a daily basis" and "closing the remaining position on an hourly basis in real-time markets." This is an unambiguous description of day-ahead and real-time market activities. The entire foundation of AWEC's double-counting argument rests on these incomplete and misleadingly presented quotes. As the full statements demonstrate, our testimony has always been clear and consistent: the DA/RT adjustment is for day-ahead and real-time balancing, and it is entirely separate from the costs of executing forward market transactions.

Q. AWEC claims that since the hedge price and the market price in the model are the same, there should be no cost.[44] Is that true?

A. No. As explained above in response to Staff, the cost we are modeling is not a difference in price but rather, an unavoidable *transaction cost* that arises from the structure of the forward market, as illustrated below:

[42] Mullins, Exh. BGM-1CT at 55:16-18 (quoting Mitchell, Exh. RJM-8 at 2:10-12).
[43] Mitchell, Exh. RJM-8 at 2:12-14.
[44] Mullins, Exh. BGM-1CT at 57:14-16.

What is the Real Cost of Hedging?

The cost isn't a difference in price over time. It's an unavoidable, upfront transaction cost that comes from the structure of the market, best exemplified by the "bid-ask spread."

The "Crate of Apples" Analogy

Imagine you need a dozen apples a week for three months. To get a stable price, you must buy a whole crate from a farmer—far more than you need.

You take the dozen you need, then sell the rest back to a local grocer. The grocer will always pay you slightly less than you paid the farmer. That real loss is the transaction cost.

This is how hedging works. We must buy large, quarterly blocks of power to secure the energy needed for a few key hours. We sell back the excess at an unavoidable loss. This is the cost the Hedging Adjustment captures.

Visualizing the Concept of the Bid-Ask Spread

The "Ask" price (purchase) is always slightly higher than the "Bid" price (sale). This difference is a type of transaction cost.

Q. So, the cost you are modeling comes from buying a big block of power when you only need parts of it?

A. Exactly. As mentioned before, in the real-world forward electricity market, we cannot surgically purchase months in advance power for just a few specific high-demand hours. That product simply does not exist for the large volumes we need. Instead, market participants offer power in large, standardized blocks. The most common products are quarterly blocks of "Heavy Load Hour" or "HLH" energy, which covers the 16 peak hours of the day, and "Light Load Hour" or "LLH" energy, which covers the 8 off-peak hours.

If our analysis shows that we need to hedge for a few high-priced peak hours during the summer, we cannot just buy power for those specific hours. We must purchase an entire quarterly block of HLH power. This means we are buying power for all 16 peak hours of every single day for three straight months. Naturally, we will not need all of that energy. The energy we do not need, we must then sell back to the market in the day-ahead timeframe. And just like with the apples, when we sell that power back, we do so at a slight loss due to a fundamental market principle. This unavoidable transaction cost is a real cost of doing business to secure the hedges our customers need. To not include this cost in our forecast would be to ignore a real and predictable operational expense. This is the concept of the "bid-ask spread" that we mentioned earlier.

iii. Addressing Secondary Arguments and Recommendations

Q. AWEC also argues that these hedges should not be included because they are "hypothetical" and the contracts have not been actually signed yet.[45] Is that a valid concern?

A. No. As discussed above, many elements of the NPC forecast reflect costs that have not yet been incurred because we are forecasting the costs to serve customers for the test year 2026. By its very definition, *almost everything* in this forecast is "hypothetical" because it has not happened yet.

Q. AWEC states that we cannot know if hedging will raise or lower costs because future spot market prices are unknown.[46] How can you include a cost if you do not know the future?

A. Here again, AWEC is confusing two completely different things. They are referring to the ultimate *"after-the-fact" value* of the hedge, which compares a locked-in

[45] Mullins, Exh. BGM-1CT at 52:12-13.
[46] Mullins, Exh. BGM-1CT at 53:16-54:2.

forward market transaction price, taken months in advance of the day of delivery, to the eventual "actual" market price in 2026. It is true that we do not know today whether that comparison will result in a "gain" or a "loss." If market prices in 2026 are higher than our hedge price in actual operations, the hedge will have saved customers money. If they are lower, the hedge will have cost more than buying on the spot market. That outcome is indeed unknown.

However, that is **not** the cost we are modeling in this adjustment. We are modeling the *transaction cost* of executing the hedge in the first place—the cost we described with the crate-of-apples analogy. This **transaction cost**, which arises from buying in blocks and incurring a bid-ask spread type of cost, is a real and foreseeable consequence of implementing our hedging program. This cost will be incurred regardless of what the spot market prices do in 2026. It is a known cost of doing business.

To ignore this known transaction cost would be to knowingly and improperly understate our expected costs to serve customers. It would be equivalent to a delivery company creating its budget but deciding not to include the cost of fuel for its trucks because it does not know exactly what the price of fuel will be in the future. We know the transaction must happen, and we know there is that **transaction cost** associated with it. A prudent forecast must include a reasonable estimate of that cost.

Q. AWEC also claims that these hedging costs reflect compliance costs associated with the Western Resource Adequacy Program (WRAP) and because the WRAP is not binding in 2026 the costs should be removed.[47] Could you please clarify how the WRAP relates to the hedging costs included in the 2026 forecast?

A. Yes. The WRAP is a landmark regional effort across the entire western United States to ensure long-term grid reliability. It establishes a common framework for utilities to demonstrate they have sufficient resources to meet customer demand, especially during extreme weather events.

AWEC is correct that the financial penalties for the WRAP program are not scheduled to become binding until after the 2026 test period. However, their conclusion that we should therefore ignore the underlying resource adequacy risk is deeply flawed and contrary to prudent utility practice. We are not forecasting or requesting recovery of any WRAP compliance penalties in this adjustment.

Instead, we are managing two very real risks that exist today—in this case, the physical risk of not having enough power to serve our customers during peak demand and the financial risk of price volatility.[48] The need to maintain a reliable supply of electricity does not magically appear on the day a program becomes "binding," The risk is real, and it exists in 2026. We are using the WRAP framework as a tool because it is the emerging, industry-accepted standard in the West for measuring and managing this supply risk. It provides a prudent and transparent benchmark for determining how much hedging is necessary to ensure reliability. It would be irresponsible for us to ignore this known physical risk and the industry's best practice

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[47] Mullins, Exh. BGM-1CT at 52:15-18.
[48] Price risk and the associated price volatility was discussed previously.

for managing it, simply because the associated financial penalties have not yet taken effect. Prudent utility management requires us to prepare for foreseeable challenges, not to wait for a crisis before we act.

Q. To conclude, could you summarize why the Commission should accept the Company's proposed hedging adjustment and reject AWEC's recommendation?

A. In summary, the Commission should adopt the Company's proposal and reject AWEC's for four clear and compelling reasons:

First, our adjustment models a real, unavoidable transaction cost. This cost is a direct result of executing our prudent risk management strategies in the forward market, an action that is necessary to protect customers from price volatility or to ensure a reliable supply of power. To ignore this cost is to approve a forecast that is knowingly incomplete.

Second, AWEC's core claim of "double-counting" is false. Their argument is built upon a fundamental confusion of two separate market activities—long-term forward market transactions and day-ahead or real-time system balancing transactions. Furthermore, this false claim is supported by a significant and concerning misrepresentation of our own testimony, where the omission of critical context changed the statement's meaning.

Third, AWEC's position is based on flawed and inconsistent logic. It requires the Commission to believe in a fictional marketplace where we can buy single hours of power years in advance, a product that does not exist. It also asks the Commission to apply an inconsistent standard where only certain "hypothetical" costs, but not others, are disallowed from the forecast, revealing a bias to simply reduce the number rather than improve its accuracy.

Finally, our forecast is a comprehensive, consistent, and accurate simulation of our real-world operations. It accounts for the actual products we must use and the real transaction costs we will incur. Adopting our proposal ensures that the costs of prudently managing risk for Washington customers are fairly and accurately reflected in rates. Rejecting it, as AWEC proposes, would create an inaccurate forecast based on flawed logic and misrepresented evidence, and would fail to account for real costs, which is ultimately not in the public interest.

5. AWEC – Wind Generation Forecasts

i. Foundational Principles of a Reliable and Affordable Power Grid

Q. As background for understanding the issues in AWEC's modeling of wind generation, please explain, in the simplest terms, the Company's most important responsibility as an electric utility.

A. The single most important responsibility of an electric utility is to ensure the reliability of the power grid. This means keeping the lights on for all customers, 24 hours a day, 7 days a week, without interruption, in a safe manner. While affordability is a critical goal that we pursue every day, reliability is the absolute foundation upon which our entire electric system is built. Without a reliable grid, the affordability of electricity becomes a moot point, as a system prone to blackouts cannot effectively power homes, hospitals, or businesses, regardless of the price.

Q. What is required on a moment-to-moment basis to maintain system reliability?

A. The central challenge of operating a reliable power grid is maintaining a perfect, instantaneous balance between the amount of electricity being generated and the amount of electricity being consumed by customers. This is a delicate and constant balancing act. Unlike water, which can be stored in a reservoir, electricity cannot yet be easily stored in large quantities, so it must be produced at the exact same moment it is needed. This balance is measured by the grid's frequency, which in North America is maintained at a constant 60 Hertz. If generation exceeds demand, the frequency rises; if demand exceeds generation, the frequency falls. Even small deviations from 60 Hertz can damage sensitive electronics and, if left uncorrected, can lead to a cascading failure of equipment across the grid, resulting in widespread blackouts. The entity responsible for performing this critical function is known as a Balancing Authority, a role the Company fulfills for its service territory.

Q. If the Company must keep supply and demand perfectly matched at all times, how do you decide which power plants to use to generate that electricity, especially when you have many different types like coal, natural gas, hydro, and wind?

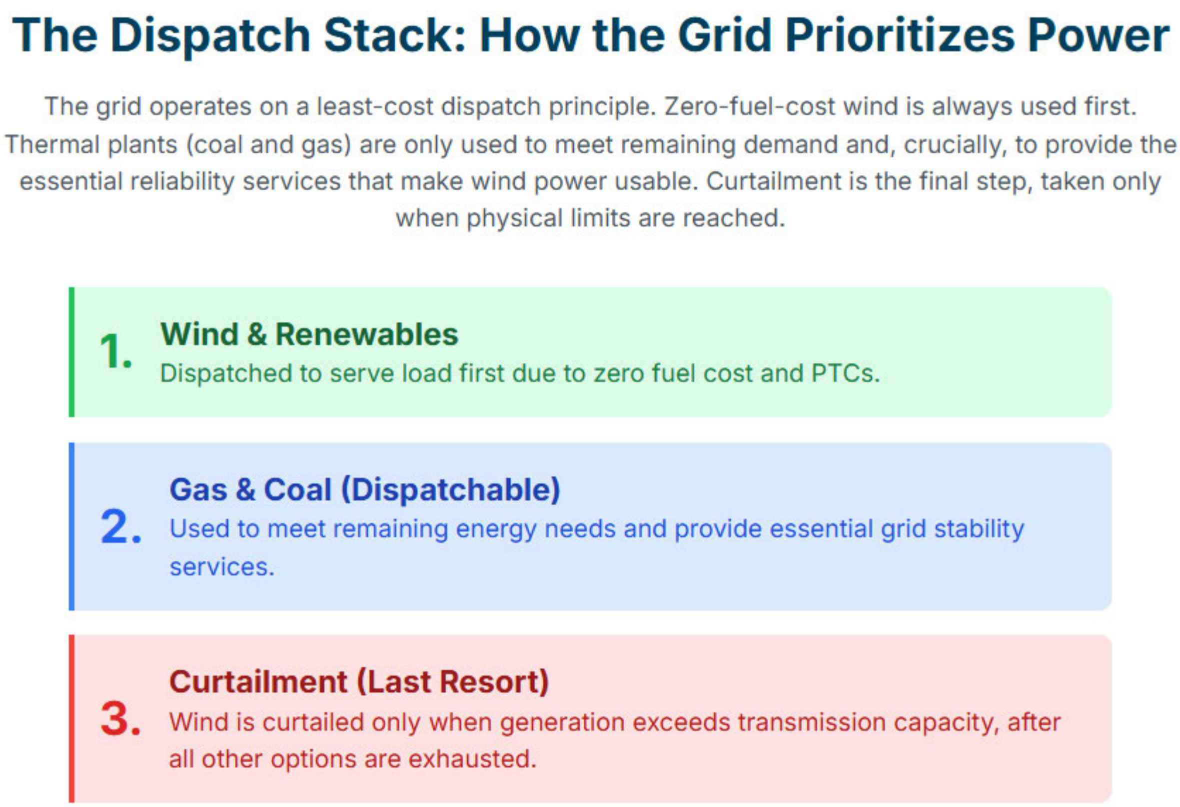
A. To decide which power plants to use, or dispatch, we follow a fundamental principle called **least-cost economic dispatch**. Imagine all of our available power plants lined up in order from the cheapest to the most expensive to operate in any given hour. This is often called the "merit order" or "dispatch stack." Resources with no fuel cost, like wind and solar, are at the very front of the line—they are the cheapest. They are followed by low-cost resources like our large hydroelectric dams, and then by resources that require fuel, such as natural gas and coal plants.

When customer demand for electricity is low, we only need to use the power plants at the front of the line—the cheapest ones. As demand increases throughout the day, we move down the line, turning on or ramping up the next-cheapest power plant in the merit order until the supply of electricity perfectly matches the demand. This process ensures that, at all times, we are using the lowest-cost combination of resources available to serve our customers, which helps keep their bills as low as possible.

Q. So, if wind power has no fuel cost and is the cheapest, does that mean you always use every single megawatt of wind energy that is available before using any other type of power plant?

A. That is the ideal economic scenario, and it is the starting point for our dispatch decisions. However, the principle of least-cost economic dispatch does not operate in a vacuum. It is always subject to a higher, non-negotiable principle: the physical and reliability limits of the power grid. The laws of physics and the need to prevent blackouts always come first.

There are two primary types of constraints that can prevent us from using the cheapest available electricity. The first is **transmission congestion**, which occurs when there is not enough capacity on the power lines to move the electricity from where it is generated to where it is needed. The second involves **reliability constraints**, which includes the need to hold a portion of our dispatchable power plants in reserve to respond to sudden changes in demand or supply, a service known as **ancillary services**. Therefore, the full operational principle is more accurately described as *security-constrained, least-cost economic dispatch*. This means we always dispatch the lowest-cost resources *up to the point that we encounter a physical or reliability limit*. At that point, reliability must take precedence, even if it means we cannot use all of the cheapest power available in that specific location at that specific moment.



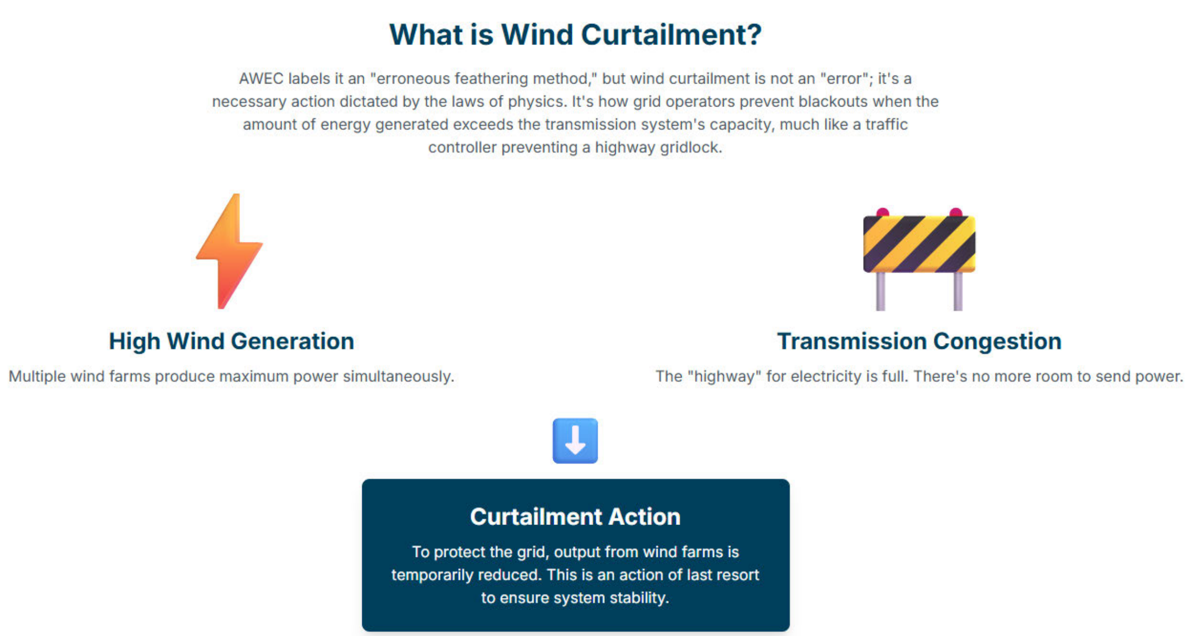
ii. Deconstructing the "Wind Production Penalty" Allegation

Q. AWEC claims that the Company is applying a "Wind Production Penalty" in its power cost model and that this penalty is unfairly increasing costs for Washington customers by about $19.5 million.[49] Could you please explain what they are referring to and whether it is accurate to call it a "penalty"?

A. Yes. The term "penalty" is a highly misleading characterization of a standard and necessary function of power system modeling and operations. What AWEC refers to as a "penalty" is, in reality, the model's simulation of **wind curtailment**, as discussed

[49] Mullins, Exh. BGM-1CT at 21:17-22:16.

in more detail by Company witness Zacharia. Curtailment is an operational instruction given by a grid operator to a generator to temporarily reduce its power output. It is not a penalty; it is an essential tool for managing the physical limitations of the power grid. As we just discussed, our primary duty is to maintain the reliability of the system by ensuring that the physical limits of our equipment, like transmission lines, are never exceeded. When the amount of electricity being generated in a specific area is greater than the capacity of the transmission lines to carry that power away, we must reduce, or curtail, some of that generation to prevent the lines from overloading and failing. The Company's production cost model, Aurora, is designed to simulate the real world. The fact that it models wind curtailment is not a flaw; it is a sign that the model is accurately reflecting the real-world physical constraints of our transmission system.



Q. AWEC claims that transmission is not the real issue and that there is "ample transmission capability in the model[.]"[50] Is there a physical bottleneck on your system that forces you to curtail wind?

A. Yes, there is a significant and well-understood physical bottleneck in eastern Wyoming, which is where a majority of the wind resources that serve Washington are located. To understand this, it is helpful to use an analogy. Imagine a region with several large, four-lane highways—representing our wind farms, coal plants, and natural gas plants in eastern Wyoming—all capable of carrying a tremendous amount of traffic. However, all of these highways must eventually merge onto a single, two-lane road to leave the region. That two-lane road represents our transmission lines.

Even if the highways are not full, if too much traffic from all of them tries to merge onto the two-lane road at the same time, you will have a massive traffic jam, or congestion. In the electric grid, this is called **transmission congestion**. The total generation *capacity* in eastern Wyoming—the sum of the maximum potential output from all wind, coal, and gas plants—is significantly greater than the total transmission *capacity* available to move that power to customers. This is a deliberate and prudent design. It would be prohibitively expensive for customers to build a ten-lane transmission superhighway that would be fully used only for a few hours a year during the absolute windiest conditions. Wind farms, on average, only produce power at 30 to 60 percent of their maximum capacity. Therefore, the most cost-effective solution for customers is to build a transmission system that can handle the *typical* output and then manage the rare periods of extreme output through curtailment. This

[50] Mullins, Exh. BGM-1CT at 34:2-3.

is precisely what our model simulates, because it is precisely what happens in reality.

Q. AWEC specifically claims that the model is curtailing wind in order to allow coal plants to generate more power, which seems to go against the least-cost principle you described.[51] When congestion occurs in eastern Wyoming, which power plants do you actually curtail first?

A. This is a critical point, and AWEC's claim is factually incorrect. The dispatch hierarchy in eastern Wyoming during a period of transmission congestion is designed to maximize the use of zero-fuel-cost wind energy while respecting the physical operating limits of all power plants. The operational sequence is as follows: First, we reduce the output of our natural gas plants down to their minimum stable operating level. Second, we reduce the output of our coal plants down to their minimum stable operating level. It is only after these dispatchable thermal plants have been turned down as low as they can safely go that we, as a last resort, begin to curtail wind generation to keep the total output within the limits of the transmission lines. Wind is the last resource to be curtailed, not the first. The Company's model correctly simulates this real-world dispatch order, which adheres to both least-cost principles and the inviolable laws of physics and reliability.

[51] Mullins, Exh. BGM-1CT at 36:8-21.

iii. Addressing AWEC's Flawed Evidentiary Claims

Q. AWEC presents several pieces of evidence to support its claim that your model is flawed. First, they point out that the level of curtailment in your model—21.1 percent—is much higher than the 1.4 percent seen in the Western Energy Imbalance Market, or WEIM.[52] Why is there such a large difference between your model and this real-world data?

A. That comparison is an apples-to-oranges comparison, and it demonstrates a fundamental misunderstanding of how the power grid is scheduled and operated. The total amount of wind curtailment that occurs is the sum of many actions across different timeframes. Think of it like planning a long road trip.

The **Aurora model** is like your initial, detailed travel plan created the day before you leave. You look at the map, see a major bridge is closed for construction (a known transmission constraint), and plan your route to avoid it entirely. This initial plan, which already accounts for major known constraints, is called a "base schedule" in our industry. The vast majority of curtailment happens at this day-ahead planning stage in Aurora, where we schedule our resources based on forecasted wind and known transmission limits.

The WEIM data that AWEC cites represents only a tiny fraction of the picture. It is like a last-minute traffic alert you get on your phone while you are already driving. The WEIM is a real-time market that makes small, five-minute adjustments to the plan to handle unexpected changes, like a sudden gust of wind or a minor fender-bender on the road. The curtailment instructions from the WEIM that

[52] Mullins, Exh. BGM-1CT at 29:21-30:9.

AWEC references are only these small, incremental adjustments relative to the schedule from 15 minutes prior. They do not include the much larger volume of curtailment that was already baked into the day-ahead base schedule. Furthermore, the WEIM data does not include reliability-based curtailments that the Company must execute in its role as the Balancing Authority. Therefore, it is entirely expected and correct that the total curtailment forecasted in our comprehensive, day-ahead Aurora model is significantly larger than the small, real-time adjustments captured in the specific WEIM data AWEC has chosen to highlight.

Q. AWEC also brings up the new Gateway South transmission line and cites the Company's own statements that this new line has "sharply" reduced actual wind curtailments, yet your 2026 forecast still shows significant curtailment.[53] Are you ignoring the benefits of this new line in your model?

A. No, we are not. The Gateway South transmission line is fully included in our 2026 forecast model, and it significantly reduces overall curtailment compared to a scenario without it. However, AWEC is again making a misleading comparison. The statement they cite compares actual, operational curtailment in the years *before* Gateway South was in service (2024) to the years *after* it was in service (2025). That is a real-world, year-over-year comparison showing an operational improvement, which is absolutely true.

What AWEC is criticizing in our 2026 forecast is something completely different. They are looking at the difference between the *unconstrained wind*

[53] Mullins, Exh. BGM-1CT at 32:25-34:9.

generation inputs[54] to the model and the *constrained wind generation outputs* from the model, all for a single year, 2026. This is an internal modeling calculation, not a year-over-year comparison. The model correctly shows that, even with the added capacity of Gateway South, there can still be specific hours during the year when wind production in eastern Wyoming is so high that it exceeds the capacity of *all* the transmission lines combined, including Gateway South. So, while the new line can reduce the *frequency* and *volume* of curtailment, it does not eliminate the physical possibility of it entirely. Comparing a real-world "before and after" operational statistic to a single-year "input vs. output" modeling delta is analytically incorrect.

Q. AWEC also claims that when wind is curtailed in the WEIM, the Company is paid and receives "replacement energy."[55] Is that true?

A. That statement is factually incorrect and reflects a misunderstanding of how market settlements for internal congestion work. For transmission congestion that is internal to a single Balancing Authority's area, like the constraints in eastern Wyoming, there is **no net revenue received or net cost paid** by the utility. The settlement process is designed to be a financial wash. While the curtailed generator is paid the prevailing market price, the Company's load customers in that same area are charged that same price, and settlement offsets ensure the two sides of the transaction cancel each other out.

The logic behind this is fundamental to market design. If a utility could generate a net profit from its own internal transmission bottlenecks, it would create a

[54] AWEC refers to this input as "P50" generation, but it is more properly known as "pre-construction vintage generation forecasts."
[55] Mullins, Exh. BGM-1CT at 29:13-18.

perverse incentive to neglect or even dismantle its transmission system to maximize curtailments and revenue. That would be nonsensical and directly harmful to customers. Because nearly all curtailments in eastern Wyoming, both in reality and in our model, are due to these internal transmission constraints, the notion that the Company receives "replacement energy" or profits from these events is incorrect.

Q. AWEC also claims that "the pre-construction [vintage] forecasts were used as the basis for investing many billions of dollars in new wind and transmission assets across the west."[56] Is this another incorrect statement?

A. Yes, AWEC's claim is again factually incorrect. Pre-construction vintage forecasts serve a limited and specific purpose: they provide a standardized, probabilistic estimate of wind resource potential at a site. They are useful for comparing sites and informing initial project design. However, they are not used by the Company—or any prudent utility—as the basis for economic justification of wind investments. Instead, the Company relies on the present value of revenue requirement (PVRR) from production cost modeling in the Integrated Resource Planning arena. This modeling incorporates: (1) realistic dispatch constraints; (2) transmission bottlenecks; (3) portfolio-wide interactions; and (4) the economic value of energy, capacity, and tax credits. Therefore, the decision to build is based on system-wide economics, not on the theoretical output of a single project under ideal conditions.

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[56] Mullins, Exh. BGM-1CT at 28:10-12.

Q. Lastly, is it true that "to the extent that curtailments are necessary in the total-company NPC modeling, it is due to the fact that they are benefiting other states, not Washington customers, and should be reversed through the Washington-allocated NPC on that basis as well[,]" as AWEC asserts?[57]

A. No. At the risk of being repetitive, curtailments in total-company NPC modeling arise from physical system constraints—e.g., transmission congestion, physical unit minimums, reliability limits—not from an intent to "benefit other states" at Washington's expense. The model optimizes dispatch on a single integrated system (as the grid actually operates), and only after that system-optimal dispatch are costs and benefits allocated to Washington using the approved inter-jurisdictional allocation methodology. Under that framework, Washington receives its proportionate share of both the low-cost energy that reduces NPC and any curtailment-related effects when constraints "bind." Selectively "reversing" curtailments just for Washington would double-count benefits, break the consistency between physical operations and cost assignment, and bias NPC results away from an accurate depiction of how costs are incurred.

This has been noted before in other contexts in this testimony, but AWEC provides absolutely no evidence, no analysis, and no data to establish a causal link between wind curtailments and things that they claim are "benefiting other states".

[57] Mullins, Exh. BGM-1CT at 35:6-9.

iv. Exposing the Critical Flaws in AWEC's "Must-Run" Model

Q. To solve what it calls the "Wind Production Penalty," AWEC performed its own modeling where it treated all wind resources as "must-run," meaning the model could not curtail them. It claims this approach still respected all transmission constraints and resulted in over $182 million in system-wide savings.[58] How is it possible for their model to achieve such different results if it used the same transmission limits?

A. It is possible only because AWEC's model achieved these "savings" by simulating a power system that defies the laws of physics and violates fundamental principles of grid reliability. Their model is not a realistic representation of any operable power system. Our analysis of AWEC's modeling reveals two fatal flaws.

First, to make room on the transmission lines for the "must-run" wind, AWEC's model forced the coal plants in eastern Wyoming to operate in a physically impossible manner. As discussed above, thermal power plants have a minimum load level below which they cannot operate safely or stably. AWEC's model simply ignored this physical constraint. Our analysis shows that AWEC's model simulated [redacted]. This is equivalent to a simulation showing a car driving with its engine turned off. It is a physically impossible scenario, and any "savings" derived from it are illusory.

Q. You mentioned two flaws. What was the second one?

A. The second flaw is just as serious. To accommodate the excess wind energy,

[58] Mullins, Exh. BGM-1CT at 34:12-16.

AWEC's model also discarded essential reliability services that are required to keep the grid stable. Specifically, it failed to hold a sufficient amount of **regulation reserves**.

To re-use an analogy, think of the grid's supply-demand balance as a car driving down the highway. The variable output from wind and solar is like a bumpy, uneven road surface. Regulation reserves are like the car's suspension and steering system; they are provided by dispatchable power plants that can adjust their output up and down every few seconds to smooth out the bumps and keep the car driving straight and stable. Without these reserves, the grid would become unstable and prone to blackouts, especially with high amounts of renewable energy.

AWEC's model achieved its results by effectively [redacted]—a level that is abysmally low and would never be acceptable in real-world operations. AWEC's model generated "savings" by simulating an unreliable and dangerously unstable power grid.

[redacted]

Q. So, to be perfectly clear, the savings that AWEC claims to have found are not real savings that could be achieved in actual operations?

A. That is correct. The savings are an illusion. They are a phantom number generated by a computer model that was allowed to break the fundamental rules of physics and grid reliability. Adopting a plan based on AWEC's modeling would be a dereliction of our collective duty to provide safe and reliable power. It is based on a simulation of a system that cannot exist in the real world. Company witness Zacharia provides further technical details on AWEC's modeling and identifies the various changes which drive these unreliable results.

v. Correcting the Record on the True Drivers of System Operations

Q. AWEC also places significant blame on the Company's take-or-pay coal contracts, claiming they include "liquidated damages" and force the model to uneconomically use coal instead of wind.[59] Is this an accurate description of those contracts and how they are modeled?

A. No, it is not accurate in two key respects. First, and most importantly, a number of the contracts AWEC allude to **do not contain liquidated damages provisions**. That implication is unsupported by the record. Rather, it is standard industry practice for coal supply contracts to include a minimum take requirement and the Company cannot obtain coal supplies for its plants without committing to a minimum volume. It is also important to note that the pricing in a coal contract is based on the minimum take volumes, i.e., a higher minimum take will typically result in a lower price and vice versa. So, in any modeling that assumes lower minimum take amounts (or no minimum take amounts) there must be a corresponding price increase to reflect the reality of the coal markets.

Second, AWEC misunderstands how these contracts are modeled. The take-or-pay provisions are modeled as an **annual** constraint, not an hourly one, contrary to AWEC's claim.[60] Company witness Zacharia discusses the specific misunderstandings that led to AWEC's mistaken claim. The Company's use of annual constraints provides the Aurora model with the flexibility to optimize the coal burn across all 8,760 hours of the year to meet the annual requirement in the most economic way possible. It does not force the model to burn a specific amount of coal

[59] Mullins, Exh. BGM-1CT at 36:10-16.
[60] Mullins, Exh. BGM-1CT at 36:16-19.

in any given hour. This allows the model to ramp coal generation down significantly during windy periods and ramp it up during calm periods, always prioritizing wind energy whenever transmission is available, consistent with least-cost dispatch.

Q. For clarification, what is a take-or-pay contract?

A. A take-or-pay coal contract is a supply agreement that obligates the Company to pay for a minimum quantity of coal over a specified period. This structure is an advantageous component of a coal contract because it enables the Company to secure favorable pricing terms, avoid volatile spot market risks—to the extent that an alternative spot market exists—and ensure reliable fuel supply for the coal-fired generation fleet. Without such provisions, suppliers would face revenue uncertainty and demand higher prices, making the coal contract economically impractical. Moreover, the contract price is directly tied to the minimum-take volume, meaning that reducing the volume would necessitate a higher price.

Q. AWEC also argues that since Washington customers no longer pay for coal plants in their rates, they should not be impacted by their operation. From a Washington customer's perspective, why should they care about the operation of coal and gas plants in other states?

A. That question reveals the central flaw in AWEC's entire argument. They are viewing the electric grid as a collection of separate, isolated parts, when in reality it is a single, deeply interconnected machine. As previously mentioned, Washington customers receive a direct, profound, and indispensable benefit from the dispatchable coal and gas plants located elsewhere on our system, even though those plants are not in their rates.

As discussed above, integrating large amounts of variable wind energy is a significant challenge for grid stability. The very same coal and gas plants that AWEC criticizes are the primary providers of the essential **ancillary services**—like the regulation reserves we talked about—that make this integration possible. These dispatchable plants act as the shock absorbers for the entire grid. They provide the stability and flexibility that allows the system to absorb the massive amount of wind energy allocated to Washington customers. Without the stabilizing services provided by this dispatchable fleet, the wind energy would be unusable and unreliable.

AWEC's logic, if taken to its conclusion, would be detrimental to Washington customers. If we were to model Washington as a "reliability island," responsible for integrating its renewable portfolio using only its own allocated resources, by balancing authority,[61] the costs would skyrocket. Washington currently does not have enough dispatchable resources of its own to manage its renewable allocation. It would need to build or procure a substantial amount of new dispatchable resources to provide these essential services. This would cause a substantial increase in rates for Washington customers. In essence, Washington customers benefit from the reliability and scale of an integrated, multi-state system. AWEC's proposal would have them receive the benefits of that system—access to Wyoming wind—while ignoring the operational realities and integrated costs required to reliably deliver it. Our modeling approach, in contrast, recognizes this interconnected reality and produces a forecast that is not only more accurate but is based on a plan to deliver energy that is both reliable and affordable for all customers we serve.

[61] NERC Reliability Standard BAL-001-2, B.R2.

Q. What data support your claim of a more accurate wind generation forecast?

A. Confidential Figure 1 and Confidential Table 1 below provides historical, actual, Company-owned wind generation, compared with the prevailing, forecast, Company-owned wind generation from previous general rate cases (GRC) or PCORCs. A couple items of note are presented below.

First, Company-owned wind generation has been consistently over-forecasted since the beginning of the WIJAM, inclusive of year-to-date, then extrapolated, calendar year 2025 wind generation. **Second**, new wind projects were placed into service in 2025; however, no new wind projects are forecast to be put into service in 2026—and the prior 2025 forecast already incorporated Gateway South. Therefore, it should be expected that 2026 wind generation will be approximately equivalent to (trending *slightly* higher than) 2025 wind generation.

AWEC's wind generation forecast of **9.90 million megawatt-hour** (MWh)[62] is an extreme outlier in the context of historical, actual wind generation—that has trended between a low of 6.7 million MWh in 2021 to an extrapolated high of 7.4 million MWh in 2025. By contrast, the Company's direct testimony estimated 7.8 million MWh of Company-owned wind generation for 2026, and a more recent forecast estimates 8.8 million MWh for 2026. **Both those Company numbers are themselves over-forecasted** as compared to 2025. The suggestion or implication that 2026 actual wind generation will be approximately 9.9 million MWh, as AWEC has calculated within their supporting NPC forecast, is not supported by any historical, actual, Company-owned wind generation data, and not supported by any reasonable

[62] As presented in AWEC's NPC report, 250224-AWEC-BGM-WP16C-WAxBridger12-8-20-2025 (C), which contains their final modeled recommendation.

future extrapolation of that historical, actual data.

Confidential Figure 1: Wind Generation Actual - Forecast

[redacted]

Confidential Table 1: Wind Generation Actual - Forecast

[redacted]

6. AWEC – Non-Precedential

i. Clarifying Scope, Precedent and Evidence

Q. What non-precedential modeling improvements have the Company proposed in this case?

A. In my direct testimony, it was explained that the Company has included in this case all non-precedential modeling improvements from the 2023 GRC.[63] These modeling improvements include the DA/RT volume component correction and the inclusion of market sales capacity limits for all power trading hubs.

Q. AWEC claims that the Commission has already rejected these modeling changes in a prior case, the 2023 General Rate Case, or GRC.[64] Do you agree?

A. No. First, the Commission's order in the 2023 GRC did not address market capacity sales limits (market caps) modeling at all. Second, the Commission did not approve the Company's DA/RT modeling improvement but did so primarily because the improvement was presented for the first time in rebuttal testimony.[65] Indeed, the Commission was clear that it "reserve[d] the right to revisit this issue in the near future once we have obtained the necessary evidence to analyze and give due consideration to the means and methodology used to calculate the update to the DA/RT adjustment."[66] To address the evidentiary concerns raised by the Commission in the 2023 GRC, the Company presented the evidence supporting the DA/RT modeling change as part of its direct case to allow sufficient time for parties to study

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[63] Mitchell, Exh. RJM-1CT at 35:14-17.
[64] Mullins, Exh. BGM-1CT at 59:6-18.
[65] *Wash. Utils. & Transp. Comm'n v. PacifiCorp, dba Pac. Power & Light Co.*, Docket Nos. UE-230172 and UE-210852 (consolidated), Order 08/06 at ¶ 311 (Mar. 19, 2024) [hereinafter "2023 GRC Order"].
[66] 2023 GRC Order at ¶ 311.

and understand the change.[67]

Q. AWEC claims that your direct testimony contains only "two sentences" describing the "DA/RT" and "Market Caps" modeling changes.[68] Is that accurate?

A. No, that is not accurate, and it reflects a fundamental misunderstanding of what constitutes testimony. My direct testimony encompassed all the evidentiary materials, **all** exhibits sponsored. In this case, twelve separate exhibits were included as part of my direct testimony supporting the NPC forecast. The detailed explanations and justifications for the modeling changes that AWEC takes issue with are contained within those exhibits, which are an integral and inseparable part of the Company's complete testimony. To claim that the testimony consists of only two sentences because the main narrative document refers to these detailed exhibits is like claiming a multi-volume encyclopedia contains only the information listed in its table of contents. The exhibits *are* the testimony. The Company has provided dozens of pages of detailed explanatory testimony and supporting data across these exhibits to support these changes.

Q. AWEC's testimony also states that in this current case, "PacifiCorp did not attempt to provide updated testimony but simply referred back to testimony from the prior proceeding."[69] Is this an accurate statement?

A. No, that statement misconstrues the evidence and demonstrates a disregard for the evidentiary record filed in this docket. In direct response to the Commission's

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[67] *Id*.
[68] Mullins, Exh. BGM-1CT at 58:11-12.
[69] Mullins, Exh. BGM-1CT at 60:7-8.

guidance, the Company has provided a substantial volume of new evidence in this case. Specifically, we filed thirty-seven pages of new, detailed testimony explaining the means and methodology of the DA/RT volume component correction, the very issue the Commission requested more information on.[70] In addition, we provided four new pages of testimony on the market caps.[71] In total, the Company has submitted over forty pages of new testimony in addition to re-introducing rebuttal testimony from the prior case to provide a complete record explaining and justifying its proposed modeling changes. In stark contrast, AWEC's testimony on these complex issues consists of only three paragraphs, with no supporting evidence or analysis.[72] The Company has not only provided updated testimony; we have provided an exhaustive and comprehensive record that directly addresses the Commission's prior concerns.

ii. The DA/RT Adjustment: Aligning Forecasts with Operational Reality

Q. Why does the Company need a DA/RT adjustment when it creates its forecast of future power costs?

A. We need the DA/RT adjustment because our forecasting model—as mentioned previously—has perfect foresight; that is, the model knows the future with 100 percent certainty and can operate the power system with perfect efficiency—which is not the case in the real world. The DA/RT adjustment is a carefully calculated, data-driven tool that accounts for two key real-world frictions that the perfect model does not see.

[70] Mitchell, Exhs. RJM-6C, RJM-7, RJM-8, and RJM-11C.
[71] Mitchell, Exh. RJM-1CT at 29:8-33:10.
[72] Mullins, Exh. BGM-1CT at 60:13-62:12.

The first friction is related to **price**. In the real world, as a utility serving customers, we do not have the luxury of only buying when prices are lowest and selling when they are highest. We must ensure power is always available. Our historical data consistently shows that, on average, we must buy power in the day-ahead and real-time markets at prices that are slightly higher than the average market price, and sell excess power at prices that are slightly lower. This small but persistent difference is a real cost of doing business, and the "price component" of the adjustment ensures this cost is included in the forecast.

The second friction is related to **volume**. As this testimony has elaborated on, in the real world, electricity is bought and sold in large, standardized 25 MW blocks—for a consecutive 16-hour or 8-hour period **in the day-ahead market**. The Aurora model, however, can transact in perfectly precise, tiny increments every single hour. Because of this, the model shows far fewer transactions are needed to balance the system than the amount of transactions we actually have to make in reality. The "volume component" adjusts the forecast to reflect the higher number of balancing transactions and the associated costs that result from trading in these real-world blocky products.

Q. AWEC claims your "volume component correction" is a fictional, ad hoc change the Company made simply because we did not like that the adjustment was reducing forecasted power costs.[73] How do you respond to that accusation?

A. That accusation is incorrect and misrepresents the purpose of the correction. The correction was not an "ad hoc" change made because we disliked a result; it was a

[73] Mullins, Exh. BGM-1CT at 60:13-22.

necessary and principled fix to a logical error in the underlying calculation that was producing an economically impossible outcome. The DA/RT volume component is specifically designed to add energy and associated costs to the forecast to account for real-world trading inefficiencies. However, due to unusual market conditions reflected in the historical data, the old, erroneous calculation produced a downward adjustment to the NPC forecast of negative (-) $5.2 million Washington-allocated in the 2023 GRC[74]—meaning it was forecasting a massive *profit* from these inefficiencies.

This result is a logical absurdity. It would be like having a model to calculate the cost of air resistance on a car and having that model conclude that air resistance actually *propels the car forward* and creates free fuel. Such a result would be an obvious sign that the model's calculation is broken. A mechanism designed to simulate the *costs* associated with real-world trading friction cannot, as a matter of basic economic logic, produce substantial and unrealistic "artificial arbitrage revenue." The correction was implemented to fix this logical flaw and ensure the adjustment functions as it was originally intended and approved to do—to model the costs of inefficiency, not to invent fictional profits.

[74] Mitchell, Exh. RJM-8 at 2:17-23.

Q. On the topic of "artificial arbitrage revenue," AWEC argues that there can be no arbitrage because the purchase and sale volumes in the adjustment are "equal and offsetting."[75] What is wrong with that line of thinking?

A. AWEC's argument conflates accounting with economics. While it is true that the megawatt-hour volumes added by the volume component are equal and offsetting, this does not mean their financial impact is zero. The error in the old calculation was precisely that it was pricing these offsetting volumes in a way that created a profit out of thin air—it was modeling the purchase of a block of energy at a low price and the simultaneous sale of that exact same block of energy at a higher price. This is the very definition of risk-free arbitrage.

In the real world, such opportunities do not exist for any meaningful length of time, because if they did, all market participants would exploit them until the prices equalized. The volume component correction prevents the NPC forecast from exploiting this fictional opportunity. It works by identifying when the calculation produces this illogical result (sales revenue greater than purchase cost for the same

[75] Mullins, Exh. BGM-1CT at 61:1-9.

offsetting block) and then it does two things: first, it flattens the prices so that they are equal, removing the artificial profit; second, it adds back a small amount of revenue that is based on *real, historically documented* arbitrage that the Company has actually achieved in its operations.[76] This correction ensures the adjustment is grounded in economic reality and does not produce "free money" from a mechanism designed to capture costs. Of note, the NPC impact of the volume component correction in this PCORC's direct testimony was identified as a *decrease* to NPC of $790,615.[77]

iii. Market Capacity Limits: A Prudent Check on a Perfect Model

Q. AWEC also takes issue with an adjustment to market sales capacity limits, or market caps.[78] To start, could you explain again what you mean when you say the Aurora model has "perfect foresight"?

A. Certainly. When we say a production cost model like Aurora has "perfect foresight," we mean that the simulation operates with complete and perfect knowledge of the future. For every single hour of the year being forecasted, the model knows exactly what customer demand will be, what fuel prices will be, and how much electricity our wind and solar farms will generate.

An analogy would be planning a cross-country road trip, but instead of just having a weather forecast, you have a perfect minute-by-minute report of future traffic, road closures, and gas prices at every single gas station for your entire route. With that perfect knowledge, you could plan the absolute cheapest and fastest trip possible. Our model does the same thing for our power system; it uses its perfect

[76] Mitchell, Exh. RJM-8 at 3:2-10.
[77] Michell, Exh. RJM-12 at 1.
[78] Mullins, Exh. BGM-1CT at 61:12-62:12.

knowledge to find the absolute lowest-cost way to operate our power plants and transact in the market. While this may be useful for analysis, it is also an unrealistic assumption that must be managed.

Q. If the model is perfect, why does it need something like a "market sales capacity limit" to hold it back?

A. The model's perfection is also its biggest weakness if left unconstrained. Because the model has perfect foresight and is programmed to find the lowest possible cost, if it identifies an hour where it can sell power for a profit, it will *assume* it can sell a virtually unlimited amount of power in that hour, if capable. It assumes the market has unlimited depth and an endless appetite for our power.

This, of course, is not how the real world works. In reality, there is a finite number of buyers and a limited amount of transmission capacity that a buyer is able to acquire. A market sales capacity limit, or market cap, acts as a necessary reality check. It is a data-driven ceiling, based on historical, auditable sales volumes, that prevents the model from assuming it can make implausibly large sales that are not achievable in the real world. Without these caps, the model would produce a forecast with artificially high sales revenues, which would lead to an artificially low forecast of power costs. This would be a disservice to customers, as it would set rates based on phantom revenues that would never actually materialize.

Q. AWEC argues that major market hubs, like the Mid-Columbia hub here in the Northwest, should not have these caps.[79] What is your response to that?

A. AWEC cites testimony previously submitted in the Company's 2023 GRC, in which

[79] Mullins, Exh. BGM-1CT at 61:19-20.

AWEC recommended that market caps should not be applied to the Mid-Columbia and Palo Verde hubs because those hubs are "liquid."[80] That is an outdated view of the market that is no longer supported by the facts. While it may have been true several years ago that certain hubs were highly liquid, recent data shows a clear and consistent trend of declining liquidity across the West. We have provided substantial evidence on this point. First, our own Company's day-ahead and real-time sales volumes have been in constant decline for over five years.[81] Second, data from the Intercontinental Exchange, a primary trading platform, shows that overall trading volumes at the Mid-Columbia hub have also been steadily trending downwards.[82]

Furthermore, the Western Interconnection as a whole is experiencing more frequent and longer-lasting energy shortages, known as Energy Emergency Alerts, or EEAs.[83] These alerts are a clear indicator that there is less surplus energy available for sale in the market. Taken together, this evidence overwhelmingly demonstrates that the assumption of unlimited market depth is no longer valid, and that applying market caps to all hubs is a prudent and necessary step to ensure our forecast is realistic. To demonstrate the magnitude of the model's over-optimization without these limits, we performed a test using our 2020 Benchmark Study that was previously referenced.[84] The results are shown below and were also presented in my direct testimony.

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[80] Mullins, Exh. BGM-1CT at 61 n.75 (citing Docket Nos. UE-230172 & UE-210852 (consolidated), Exh. BGM-1CT at 42).
[81] Mitchell, Exh. RJM-1CT at 30, Confidential Figure Market Sales Down.
[82] Mitchell, Exh. RJM-4C at 8-10.
[83] *See, e.g.*, NERC, *2023 State of Reliability Technical Assessment* at 32 (June 2023) (discussing the number of EEA-3s issued in 2022) (available at https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf).
[84] Mitchell, Exh. RJM-1CT at 32, Table 'RT_Sales' (citing Mitchell, Exh. RJM-5C).

Trading Hub	Actual Historical Real-Time Sales (MWh)	Modeled Real-Time Sales without Caps (MWh)	Over-Forecast of Sales (%)
Mid-Columbia	58,622	610,866	942%
Palo Verde	26,432	175,257	563%
Four Corners	167,616	219,509	31%

As demonstrated, without the market caps, the model forecasted sales volumes that were over nine times higher than what was actually achievable at Mid-Columbia. This is not a minor inaccuracy; it is a fundamental flaw that would produce a dangerously unrealistic forecast.

Q. Finally, AWEC is concerned that you are excluding "structured products" from the market cap calculation, which they say dilutes the value of resources for Washington customers.[85] Could you explain what these are and why you are excluding them?

A. "Structured products" is a technical term that, in this context, simply refers to forward market transactions. We are excluding these forward market transactions from the market caps calculation for a very straightforward reason: to avoid double-counting. In our current modeling approach, we are now explicitly simulating the financial impact of our forward market transactions directly within the model. The market caps, on the other hand, are designed to constrain day-ahead market sales or real-time market sales. If we were to include our forward market transactions in the historical data used to set the caps for our day-ahead market or real-time market transactions, and also model those forward market transactions separately, we would be counting

[85] Mullins, Exh. BGM-1CT at 62:5-9.

the same energy twice. This would improperly inflate the market caps and allow the model to once again forecast an unrealistic level of sales. Removing the forward market transactions from the market caps calculation is a necessary housekeeping measure to maintain the mathematical integrity and accuracy of the forecast.

iv. A Prudent Path Forward for Just and Reasonable Rates

Q. Could you summarize why the Commission should reject AWEC's recommendations regarding these modeling changes?

A. The Commission should reject AWEC's recommendations for two fundamental reasons. First, the Company produced robust and comprehensive evidence in response to the Commission's guidance in the 2023 GRC and the proposed modeling changes are therefore supported by the record.

Second, AWEC's specific technical recommendations are unsound. Their proposal to alter the Company's as-filed DA/RT adjustment would require the Commission to knowingly approve a forecast based on an economically illogical calculation that creates profit from inefficiency. Their proposal to alter the Company's as-filed market sales capacity limits is based on an outdated view of the market and would result in a forecast that relies on millions of dollars in phantom sales revenues that cannot be achieved in the real world. Indeed, Staff agrees that the Company's market sales capacity limits proposal is a reasonable improvement.[86] Adopting AWEC's position would mean choosing a less accurate, less realistic, and less principled model for the sole reason that it produces a lower NPC forecast.

[86] Wilson, JDW-1T at 46:19-21. Staff recommends additional analysis of this proposal in a future proceeding. Wilson, JDW-1T at 47:13-15.

Q. And in contrast, why should the Commission approve the modeling changes that the Company has proposed?

A. The Commission should approve the Company's modeling changes because they are reasonable, evidence-based, and necessary refinements designed to improve the accuracy and integrity of the NPC forecast. Each change is a deliberate step to align the model more closely with economic principles or operational reality. The correction to the DA/RT volume component fixes a clear logical error and ensures the model does not violate the basic economic principle that inefficiencies create costs, not profits. The application of market sales capacity limits, updated to properly account for forward market transactions, acts as a prudent guardrail that prevents the model from producing unrealistic sales forecasts, thereby protecting customers from the risk of future rate shock that would occur if rates were based on revenues that never materialize.

7. <u>AWEC – Nodal Pricing Model</u>

i. The Nodal Pricing Model - What it is and How it is Actually Used

Q. What Nodal Pricing Model (NPM) costs are at issue in this proceeding?

A. The Company has included in this case the NPM service charges that the Company will incur for the period of January 2026 through April 2026. The EDAM is expected to replace the NPM on May 1, 2026.

Q. Does AWEC recommend an adjustment to the NPM costs the Company has included in its forecast?

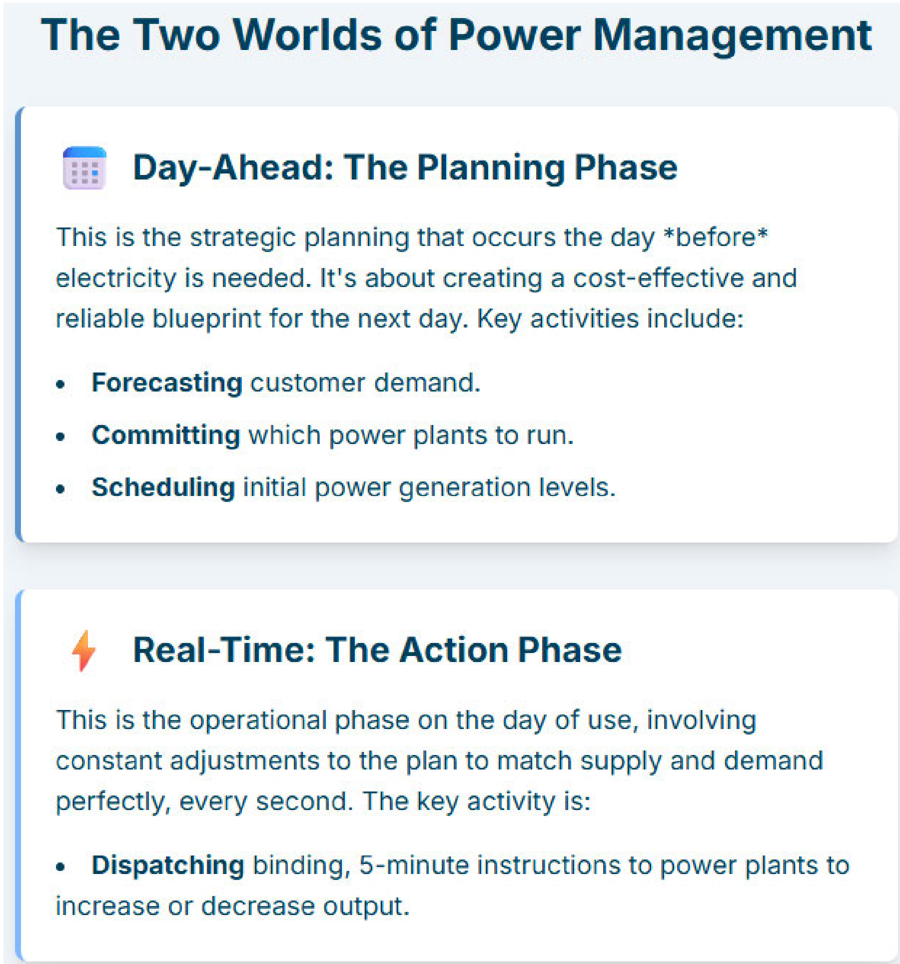
A. Yes. AWEC recommends "that all nodal pricing service charges be removed from the

PCORC."[87] AWEC asserts that NPM will "not be used in the forecast period, nor will it provide any benefits to ratepayers."[88]

Q. As an initial matter, AWEC claims that the Company represented that the NPM would be used for "system dispatch."[89] Is AWEC's claim accurate?

A. No, that claim is not accurate. It represents a fundamental mischaracterization of the NPM's purpose and a misunderstanding of the different trading timelines and process previously discussed. The Company did not represent that the NPM would be used to "dispatch" the system, and to suggest otherwise is a category error. As we have established, dispatch is a real-time, five-minute, or minute-to-minute instruction. The NPM, by design, is a day-ahead *scheduling* tool. It does not provide dispatch instructions. Instead, it provides advisory, non-binding, hourly generation schedules and unit commitments—the very first steps in the day-ahead planning phase, not the final action phase. Scheduling and dispatch are two different, though related, functions.

[87] Mullins, Exh. BGM-1CT at 50:15.
[88] Mullins, Exh. BGM-1CT at 50:17-18.
[89] Mullins, Exh. BGM-1CT at 47:4-48:4.



Q. AWEC suggests that if the Company is using the NPM, the Company uses it in a "cursory" way.[90] Is that accurate?

A. No. Far from being unused or used in a cursory manner, the NPM is an important analytical tool that our expert traders use to improve the quality of our day-ahead plan, which ultimately helps to lower costs for customers. The process is systematic and adds significant value.

Here is the daily workflow: At approximately 1:00 PM on the day before operations, the NPM produces its output. This output is a complete, optimized plan

[90] Mullins, Exh. BGM-1CT at 48:16-49:2.

for our system, suggesting which power plants to commit and what their hourly schedules should be for the next day. At the same time, our primary internal optimization model, known as PCI, produces its own version of that plan.

The crucial step happens next. Our professional traders, who have deep expertise in market dynamics and system operations, conduct a comparison of the two plans—the one from the NPM and the one from PCI. They are looking for discrepancies, differences in strategy, and potential efficiencies that one model may have identified but the other did not. This is not a simple, automated check; it is an expert, qualitative review. Think of it as getting a second opinion from another specialist before making a critical decision. This review allows our traders to synthesize the strengths of both models and use their professional judgment to create a final, improved "day-ahead setup."

This refined plan, which has benefited from the insights generated by comparing the NPM and PCI outputs, is then handed off to be the starting point for our real-time operators on the day of operations. Therefore, AWEC's claim that the NPM outputs are not received in time to be reflected in decisions is incorrect. The outputs are received in the day-ahead and directly influence the final day-ahead plan, which is precisely the plan that governs our actions in real-time the following day.

Q. AWEC states in its testimony that it has seen "no evidence" that this review process actually occurs or that it affects the final plan.[91] How do you respond to that?

A. AWEC is looking for a specific type of evidence, perhaps a formal report or a log file,

[91] Mullins, Exh. BGM-1CT at 48:20-49:2.

that does not align with the nature of the process. The value of the NPM is realized through the cognitive, analytical work of our expert traders. When they compare the two model outputs, they are applying their years of experience to make nuanced judgments. The result—the evidence—is the improved quality of the final day-ahead setup itself. To claim the process does not happen simply because one has not observed a specific type of document is a flawed conclusion. The process is recurrent, and it directly informs and improves our operational decisions.

ii. The Value Proposition - How the NPM Saves Customers Money

Q. AWEC claims the NPM provides no benefits and that the investment has been "fruitless."[92] Can you explain exactly how the NPM saves customers money?

A. The NPM provides two significant and tangible forms of financial benefits to our customers, making the investment far from fruitless. The first is through direct, operational cost savings, and the second is through indirect, but equally important, strategic savings related to our transition to a new energy market.

First, let us discuss the direct operational savings. By providing a valuable "second opinion," the NPM helps us create a more efficient day-ahead plan. A more efficient plan means we are using our power plants more economically, buying and selling power in the market more effectively, and ultimately reducing our total NPC. These savings are real, but they are embedded within our total actual NPC.

This concept of embedded savings can be difficult to quantify precisely because of what is known as a "counterfactual" problem. A counterfactual is essentially a "what if" scenario—what would our costs have been on a given day if

[92] Mullins, Exh. BGM-1CT at 49:10-12.

we had *not* used the NPM to inform our decisions? To get a perfect measurement, we would need to live the same day twice, once with the NPM's insights and once without, which is impossible.

An analogy might help clarify this. Imagine you are the manager of a large fleet of delivery trucks. You invest in a sophisticated new software that helps you optimize your daily delivery routes. At the end of the year, you see that your total fuel costs have gone down. You know the software is responsible for this improvement. However, if someone asked you to prove exactly how many dollars you saved on Tuesday, March 5th, it would be impossible. To do so, you would need to know the counterfactual: the exact route your drivers would have taken that day *without* the software's guidance. Since that route was never driven, you cannot measure it. But the lack of a separate, line-item report for "savings from software" does not mean the savings are not real. They are embedded in your lower overall fuel bill. The NPM works in the same way; its benefits are embedded in lower overall power costs for customers.

Q. What is the second type of benefit provided by the NPM?

A. The second major benefit is strategic. The NPM has effectively served as a "flight simulator" for our participation in the upcoming Extended Day-Ahead Market, or EDAM. The EDAM is the next evolution of the WEIM, and our participation is essential for ensuring we can continue to provide low-cost power to our customers.[93]

The operational logic and processes for using the NPM are nearly identical to

[93] For a discussion of the benefits of the EDAM, *see* CAISO, *Extended Day-Ahead Market Fact Sheet* (available at https://www.caiso.com/Documents/extended-day-ahead-market-edam-fact-sheet.pdf) (last visited Sept. 9, 2025).

those required to participate in the EDAM, just on a smaller scale involving only our own system. By developing, implementing, and using the NPM over the past several years, our teams have gained invaluable, hands-on experience. They have tested our systems, refined our procedures, and built expertise needed to operate successfully in a complex, nodal, day-ahead market environment. This experience has made the Company's actual transition into the EDAM smoother and more effective than it otherwise would have been.

The cost of the NPM fee is minor compared to the potential financial harm from a poorly executed transition into a new market, which could involve operational errors, compliance penalties, or implementation delays. Therefore, the costs associated with the NPM were not just an operational expense; they are a prudent, strategic investment in risk mitigation and organizational readiness that has protected and will continue to protect customers from much larger potential costs.

iii. The End of the NPM - A Necessary Evolution, not a Failure

Q. AWEC suggests that the decision to stop using the NPM in May 2026 demonstrates that the model was not useful.[94] Is that true?

A. No. The decision to terminate the NPM service is not a reflection of its value; rather, it is a necessary and unavoidable technical consequence of the evolution of the WEIM.

As previously mentioned, the Company is joining the EDAM, which is scheduled to go live on May 1, 2026. The EDAM will provide the same type of day-ahead market functions as the NPM, but on a much larger, region-wide scale, creating

[94] Mullins, Exh. BGM-1CT at 50:16-18.

even greater opportunities for efficiency and cost savings for our customers.

The NPM service is provided to us by the California Independent System Operator, known as CAISO. CAISO is also the entity that operates the upcoming EDAM. Due to technical limitations within their systems, the CAISO cannot operate both the NPM and the EDAM simultaneously for the Company. We simply have no choice in the matter; once the EDAM is implemented, the NPM service must end. This is the sole reason for its termination.

To underscore the value we see in the NPM, it is worth nothing that if it were technically possible to continue receiving the NPM outputs as a reference tool even after the EDAM goes live, we would absolutely explore that path. The fact that we are forced to discontinue the service due to external technical constraints does not in any way diminish the value it has provided and will continue to provide through April 2026.

Q. AWEC also suggests that it would have been a "prudent course of action" to terminate the NPM service earlier to save money.[95] What is your response to that?

A. Terminating the NPM service early would have been the opposite of prudent; it would have been imprudent and detrimental to customers. As we have discussed, the NPM provides real, ongoing value by helping us in our ongoing efforts to lower NPC. Voluntarily giving up a tool that saves customers money would not be a responsible action.

Furthermore, terminating the service early would mean sacrificing the crucial

[95] Mullins, Exh. BGM-1CT at 50:9-13.

final months of preparation and training that the NPM "flight simulator" provides ahead of the EDAM launch. To use an analogy, that would be like a pilot deciding to cancel the last few months of their simulator training before their first flight on a new, complex aircraft just to save on the simulator fees. It would be a foolish and needlessly risky decision. The most prudent and responsible course of action is to continue leveraging the NPM for its full benefits—both operational and strategic—right up until the moment it is replaced by the superior EDAM. That is exactly what the Company is doing.

iv. The Prudence of Including NPM Costs in Rates

Q. To conclude, could you please summarize for the Commission why the Company believes it is fair and reasonable for customers to pay the NPM service charges for the period of January 2026 through April 2026?

A. Yes. It is fair and reasonable for customers to pay for the NPM service charges through April 2026 for three primary reasons.

First, the NPM is not an abandoned or fruitless investment; it is an active and valuable tool that the Company will continue to use every day during that period. Its use as an analytical "second opinion" informs our expert traders, improves our day-ahead operational plan, and results in embedded cost savings that directly benefit customers by lowering their overall NPC.

Second, the costs incurred for the NPM already have provided significant strategic value by ensuring a smoother, cheaper, and more effective transition to the upcoming EDAM. This preparation has mitigated substantial risks and potential future costs, acting as a prudent investment that protects customers.

Finally, the NPM service is being terminated on May 1, 2026, not because it lacks value, but solely due to a technical limitation related to the launch of the superior EDAM. Customers will receive the full benefits of the NPM right up to the day it is replaced.

For these reasons, the NPM costs are prudently incurred expenses that are directly related to providing reliable, cost-effective service. Removing these legitimate charges from our forecast, as AWEC recommends, would ignore the real value delivered to customers and would result in an under-forecast of the necessary costs to serve them. Therefore, we respectfully recommend that the Commission reject AWEC's proposed adjustment, approve the NPM costs for January 2026 through April 2026, and reject NPM costs from May 2026 to December 2026.

Nodal Pricing Model: A Prudent and Necessary Investment

1 Used and Useful

The NPM is actively used to refine operational plans and generate real, embedded cost savings for customers.

2 Strategic Value

It has been an invaluable preparatory tool, mitigating risks associated with the EDAM transition.

3 Necessary Transition

Its termination is a required technical step to adopt a more advanced market, not a reflection of its performance or value.

Therefore, the NPM costs through April 2026 are a fair and reasonable expense, essential for ensuring a low-cost, reliable energy future for customers.

8. AWEC – FERC Account 509

i. Defining the Federal Accounting Reclassification

Q. AWEC asserts that the Company potentially "expanded" the definition of NPC in this case.[96] What is AWEC referring to?

A. As was explained in my direct testimony, the Company's NPC forecast includes an update of several FERC accounts. Unlike in past years, the Company has included Account 509 – Allowances in this PCORC. However, the costs that the Company will include in Account 509 were previously included in NPC through a different FERC account.

Q. Does AWEC support the Company's inclusion of Account 509 in NPC?

A. No. AWEC does not support including Account 509 in the Company's NPC at this time.[97]

Q. Could you explain what FERC Account 509 is for and why it is included in the definition of NPC?

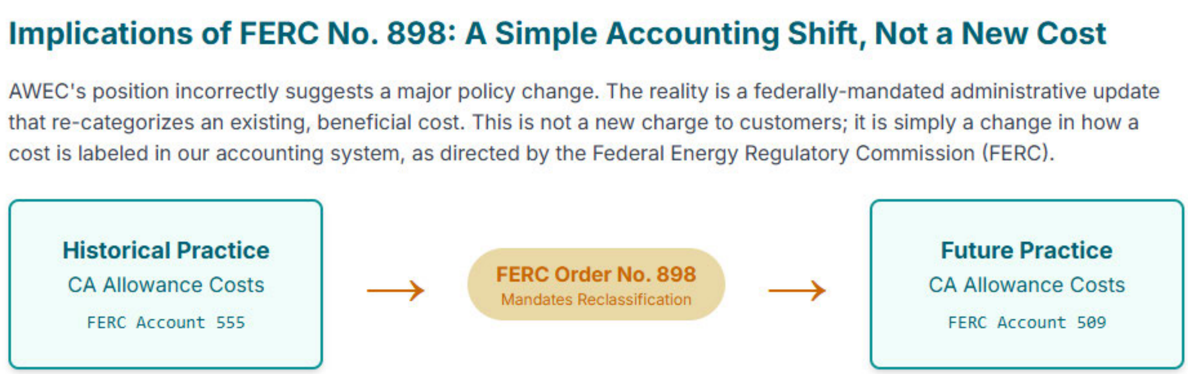
A. Yes. The inclusion of Account 509 in our list of NPC accounts is to inform the Commission of an upcoming, federally mandated change in accounting procedure. It reflects the re-categorization of a very small and specific type of cost that has *always* been a component of NPC for Washington customers.

To be precise, this involves the costs for greenhouse gas allowances associated with the California Cap-and-Trade program.[98] For many years, the

[96] Mullins, Exh. BGM-1CT at 19:1-3.
[97] Mullins, Exh. BGM-1CT at 20:10.
[98] For a summary of California's Cap-and-Trade program, *see* Cal. Pub. Utils. Comm'n, *Greenhouse Gas Cap-and-Trade Program* (available at https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program) (last visited Sept. 9, 2025).

Company has participated in the California wholesale electricity market, and the revenues from our sales in that market directly benefit Washington customers by reducing their overall power costs. To make those sales into California, we are required to purchase these allowances. Historically, the costs for these allowances have been recorded in FERC Account 555, "Purchased Power," alongside the revenues they help generate.

However, FERC, which sets the accounting rules for all utilities, has issued Order No. 898 (effective January 1, 2025) that provides direction for utilities to move the costs for these specific environmental allowances from Account 555 to a more appropriately titled account, Account 509.[99] So, to be clear, this is not a new cost being added to customer bills. It is the same historical cost, which supports revenue that lowers customer bills, simply being moved from one ledger to another as per direction from the FERC regarding our system of accounts.



[99] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, Order No. 898, 183 FERC ¶ 61,205, 88 Fed. Reg. 69,294 (Oct. 5, 2023).

ii. Rebutting AWEC's Conflation of State and Federal Issues

Q. AWEC claims that in the Company's 2023 GRC, the Company "expressly excluded allowances from NPC."[100] This seems to contradict what you have just stated. How do you reconcile these two positions?

A. That is an inaccurate characterization of our 2023 filing, and it stems from AWEC conflating two entirely separate and distinct state climate programs. In the 2023 GRC, we did propose to exclude the costs associated with *Washington's* Climate Commitment Act, or CCA, from NPC.[101] We did so for a very specific reason: Washington provides utilities like the Company with "no-cost allowances" under that program, which are designed to offset unfavorable financial impacts on Washington customers.

The costs we are discussing here, which are the subject of the change to Account 509, have nothing to do with Washington's CCA program. These are costs related to the *California* Cap-and-Trade program. These California-related costs, which, we stress again, are incurred to generate wholesale revenue that lowers Washington customers' bills, have consistently been included in NPC. AWEC's attempt to link our prudent treatment of Washington CCA costs in a prior case with this separate issue of California allowance costs is misleading and incorrect.

[100] Mullins, Exh. BGM-1CT at 19:5-6.
[101] Docket No. UE-230172, Exh. BGM-1CT at 39:7-11.

Q. AWEC also suggests that FERC Order 898 is not a substantive change, but rather is "simply codifying the currently accepted practice[.]"[102] Can you explain in more detail what FERC Order 898 is and why it was issued?

A. Yes. To characterize FERC Order 898 as a minor clarification or merely cosmetic is to misrepresent fundamentally its significance. FERC's Uniform System of Accounts is the foundational rulebook that all electric utilities must follow for their accounting. It ensures that financial information is recorded in a consistent and transparent way across the entire industry. Order 898 represents the first major overhaul of this rulebook in over a decade.

The primary purpose of the order was to modernize the accounting system to properly recognize the rapid technological changes in our industry, particularly the growth of renewable resources like wind and solar, as well as energy storage and related environmental instruments.[103] Far from just codifying old practices, the order created entirely new accounts and established a formal, uniform framework for things that were previously grouped into older, less descriptive categories. The order explicitly sought to "provide uniformity, consistency, and transparency in accounting and reporting" for these modern assets.[104] As part of this comprehensive update, FERC determined that environmental allowance costs should no longer be booked under the general "Purchased Power" account but should instead be recorded in the more specific "Allowances" account, Account 509. This is a substantive, forward-

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[102] Mullins, Exh. BGM-1CT at 20:3-7.
[103] *See* Order No. 898 at ¶ 17 (noting that FERC accounts "do[] not provide clear accounting treatment for activities related to many technological and economic developments in the U.S. energy industry of recent decades, like the growth of investments into renewable generating facilities, battery storage, and RECs, among others").
[104] Order No. 898 at ¶ 17.

looking directive that we were required to comply with by January 1, 2025.

Q. AWEC raises the complexities of Washington's CCA and the unresolved details about no-cost allowances as a reason to reject your proposal.[105] How do you respond?

A. AWEC is raising an issue that is entirely irrelevant to the matter before the Commission in this case. Their discussion of the complexities surrounding Washington's Climate Commitment Act is a distraction. The costs that will be recorded in Account 509, and which were previously in Account 555, are exclusively related to the California Cap-and-Trade program. The rules, regulations, and allowance methodologies of Washington's program have no bearing on this federally directed accounting change. Perhaps a simple illustration would help clarify this.

AWEC's Critical Error: Conflating Two Separate Programs

AWEC's argument is based on a fundamental misunderstanding. They have confused Washington's Climate Commitment Act (CCA) with California's Cap-and-Trade program. The accounting change, for Washington, applies to the California program. The complexities of Washington's CCA, which AWEC cites, are completely irrelevant to this issue, from Washington's perspective.

	California Cap-and-Trade Program	Washington Climate Commitment Act (CCA)
Relevance to Acct. 509	**✓ This is the ONLY program affected from the perspective of Washington customers.** The costs from this program will be booked to Account 509.	**✗ Not relevant to this accounting change from the perspective of Washington customers.** AWEC's concerns are misplaced here.
Financial Impact for WA	Creates a **net revenue** that lowers customer bills. Small costs enable large wholesale sales.	Costs are offset by no-cost allowances, making it a different proposition entirely.
History	A long-standing program whose costs have long been included in NPC (historically under Acct. 555).	A newer, separate state program for which Washington customers are not assessed allowance costs.

[105] Mullins, Exh. BGM-1CT at 20:12-16.

iii. Procedural Impact and Recommendation

Q. If FERC's accounting change has no impact on customer rates, how does it impact the PCORC?

A. That is the critical distinction. This proceeding, the PCORC, is a *forecasting* case. We are projecting what our net power costs will be for 2026 to set rates in advance. The inclusion of Account 509 in the definition of NPC here is purely informational—it updates the "chart of accounts" for that forecast, reflecting the new rulebook from FERC. It does not change the total forecasted dollar amount.

The Power Cost Adjustment Mechanism, or PCAM, is a backward-looking "true-up" process. After the year is over, the PCAM compares the *actual* power costs we incurred against the amounts we collected from customers through rates. If we over-collected, the difference is returned to customers; if we under-collected, we recover the difference. The actual accounting for the California allowance costs—the act of recording them in Account 509 instead of 555—began in 2025 and will be subject to a full review in the PCAM proceeding beginning in 2026.

That PCAM process is precisely the forum where the Commission can, and should, review the transactions to ensure their prudence and verify that Washington customers only bear costs that are directly associated with the wholesale revenues that benefit them. Furthermore, it is important to place this in context. The total annual amount of these California allowance costs has historically been relatively small, fluctuating between approximately $160,000 and $225,000. This is an administrative reclassification, not a new cost driver.

Q. So, to summarize: AWEC's concerns appear to be based on misunderstandings. You are saying this change is an accounting update from FERC for the sake of transparency; it deals with existing costs from a California program that benefits Washington customers; it has no immediate rate impact in this case; and Washington's separate climate program is irrelevant to this specific discussion. Is that a fair summary?

A. Yes. We are proactively complying with a new federal rule designed to improve accounting transparency. The costs in question are not new and are tied to revenues that reduce the financial burden on Washington customers. AWEC's objections are based on conflating this simple administrative matter with other, unrelated regulatory issues. We respectfully request that the Commission reject AWEC's recommendation and approve the definition of NPC as filed, which properly reflects the forthcoming requirements of FERC Order 898.

9. PUBLIC COUNSEL – Short Term Firm

i. Refuting the "Double-Collection" Claim and the Balancing Adjustment

Q. Public Counsel has presented a table that appears to show that the Company collected significantly more money for what they call "STF purchases" than the Company actually spent. For example, for the year 2021, their table shows the Company spent $370 million but collected $423 million, resulting in what they label an "over-collection" of $53 million.[106] Please explain this table.

A. This is the central point of the confusion. Public Counsel's "Table 1" is fundamentally incorrect because it adds together two completely different types of

[106] Earle, Exh. RLE-1CT at 26:6.

costs. It is the equivalent of adding a car's lease payment to its gasoline bill and claiming the total is the cost of gasoline.

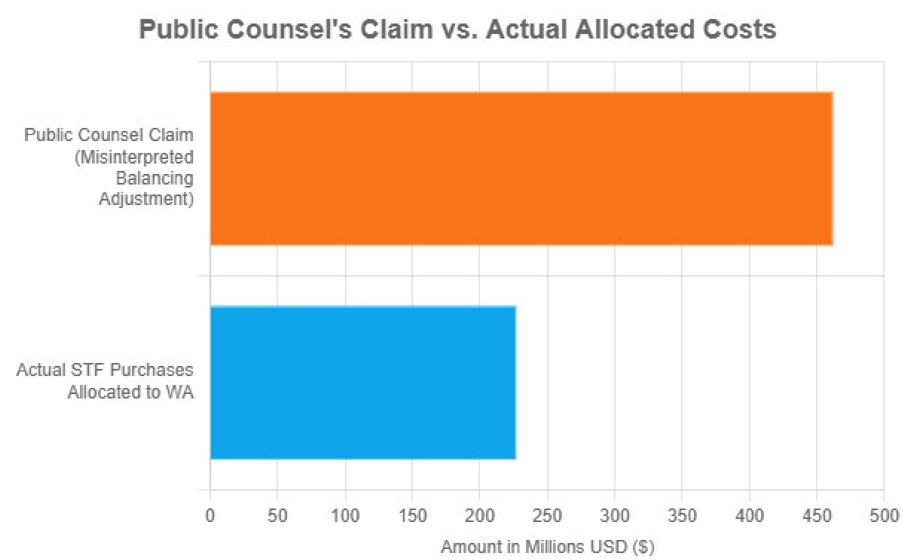
To explain this, let us expand upon that analogy. Imagine the Company as a large company with six divisions in six different states, and it provides a fleet of company cars (our power plants) for all employees to use. The total cost of this fleet has two distinct parts. First, there are the fixed costs, like the annual lease payments for all the cars. These are "non-NPC" costs. Second, there are the variable costs, like the monthly bill for all the gasoline used by the fleet. These are NPC.

Now, under the company's internal budget rules, the Washington division pays the annual lease payments (the non-NPC) for a certain number of cars. However, in the real world, Washington's employees consistently use more cars from the shared fleet than their lease budget covers. This means Washington is causing the company to incur more fixed lease costs than it is paying for. To fix this, the company uses an agreed-upon accounting rule. Instead of re-billing the complex annual lease payments, it creates a simple proxy. It values the unpaid-for car usage (energy shortfall) by looking at the average market price of gasoline that month and applies it to the extra miles driven. This valuation is a reasonable approximation for the unpaid lease costs.

Here is the crucial step that explains the confusion: for accounting convenience, this charge—which is a proxy for unpaid lease costs (a non-NPC item)—is added to Washington's portion of the monthly gasoline bill (the NPC). So, when Public Counsel looks at the company's books, they see the total amount spent on gasoline system-wide ($370 million in the 2021 example). Then they add up what all divisions were billed for gasoline and see the total is higher ($423 million). They incorrectly conclude we are "over-collecting" on gasoline costs. But we are not. We are using the gasoline bill as the vehicle to collect a proxy amount for the unpaid lease costs that Washington was responsible for. The total money collected by the company, across both lease payments and gasoline, approximates what was spent. Public Counsel has confused a legitimate charge meant to cover a non-NPC shortfall with an over-collection of NPC.

Claim vs. Reality (2021-2024)

Public Counsel's claim is based on misinterpreting a ratemaking adjustment, not on actual costs incurred by PacifiCorp.



Q. Is your issue that the numbers in Public Counsel's table are wrong or that the way they have added them together is wrong?

A. The way they have added them together is fundamentally wrong. The profound error is treating these numbers as equivalent and additive items. One represents the total cash paid by the entire six-state Company to external power markets. The other represents an internal, book-entry value—referred to as the balancing adjustment—assigned to a single state to ensure total allocated costs reflect total costs incurred under the regulatory rules. Combining them creates a fiction of an "over-collection" where none exists.

To help clarify this, it may be useful to visualize the correct way to account for these costs.[107] This visual separation makes it clear that these are two distinct concepts that cannot be combined to allege an over-collection.

Q. Please explain this "balancing adjustment." Why is it necessary, and what does it mean for Washington to have an energy "shortfall"? Does that mean there was not enough electricity for customers in Washington?

A. No, it absolutely does not mean there was a physical shortage of electricity. Our customers in Washington, and in all our states, received reliable service. The term

[107] This visualization excludes the impact of uncollected costs due to deadbands, sharing mechanisms, disallowances, etc.

"shortfall" in this context refers to a concept within the rules of ratemaking and cost allocation, not a physical lack of power.

The Company operates as a single, integrated electric system across six different states: Washington, Oregon, California, Utah, Wyoming, and Idaho. Because we operate as one large system, we achieve significant efficiencies that benefit all customers, such as sharing power plants and transmission lines. However, because each state has its own regulatory commission and its own set of customers, we have a method for dividing the total costs of that integrated system among the six states. This method is called an inter-jurisdictional cost allocation methodology. For Washington, this agreed-upon method is the Washington Inter-Jurisdictional Allocation Methodology, or WIJAM.

Under the WIJAM, Washington is allocated a "portfolio" of power generation resources—a specific share of various power plants on our system. For ratemaking purposes, we compare the amount of energy that Washington's allocated portfolio of power plants produced in a given month to the amount of energy Washington's customers actually consumed in that month. From 2021 to 2024, the total amount of energy consumed by Washington customers was greater than the energy produced by the power plants specifically allocated to Washington in our accounting. This difference is what we call a "shortfall" or a "short position." It is an accounting imbalance, not a physical one. In reality, the customers' needs were met by the full power of the entire six-state integrated system. The balancing adjustment is simply the mechanism we must use to account for the value of that extra energy Washington customers received from the broader system.

Q. The balancing adjustment is a way to put a dollar value on that accounting shortfall. Public Counsel claims this adjustment is a "hodge-podge of transactions that lack cost causation."[108] How do you respond to that, and how is the value of the adjustment actually calculated?

A. That characterization is incorrect. The balancing adjustment is the tool which ensures that customers who cause a cost to be incurred pay for it. Washington customers caused the need for energy beyond what their allocated resources produced. Therefore, they are assigned a cost associated with that energy. Without this adjustment, the costs for the energy Washington used would be effectively provided for free.

The calculation itself is designed to be simple, transparent, and grounded in real-world market prices. Instead of a complex formula attempting to track electrons, the WIJAM uses a straightforward proxy to value the energy shortfall. On a monthly basis, we calculate the weighted-average price of all the actual short-term firm power purchases we made across our entire system, and we do the same for our short-term power sales. These real market prices are then used to calculate the monetary value of Washington's MWh shortfall (or surplus) for that month. This is a logical and reasonable approach because it values the energy at a price that reflects the actual market conditions in which the Company was operating during that period. It is not a "hodge-podge"; it is a consistent and predictable formula that uses real, verifiable market data as its input.

[108] Earle, Exh. RLE-1CT at 24:14-17.

Q. On a related topic, Public Counsel seems very concerned that when they asked for proof that you did not double-collect these costs from other states, the Company responded that it is "unable to provide evidence to disprove a cost that has not occurred." They called this response "quite amazing" and suggested it means your Company cannot track its own costs.[109] Why would the Company give that response?

A. The Company gave that response because it is the most precise and factually accurate answer to the question that was asked. Public Counsel's question was based on the flawed premise that the balancing adjustment is a real, invoiceable cost that could be charged to someone else. It is not. As we have discussed, it is an internal, non-cash, after-the-fact accounting calculation.

Let us return to the company car fleet analogy. Imagine asking the company's Chief Financial Officer (CFO) to provide "evidence" that they did not also charge the other five divisions for the proxy gasoline charge that was meant to cover Washington's unpaid lease payments. The CFO rightly would be confused. They would say, "We cannot show you an invoice we didn't send to the other divisions, because the thought of sending one never existed. That extra charge is not a separate gasoline purchase we could have billed to anyone; it is a calculation we did on our internal accounting ledger to make sure Washington's total contribution was fair, by using the gasoline bill to make up for a shortfall on the lease payment side of the ledger."

That is precisely the situation here. Public Counsel is asking for an invoice

[109] Earle, Exh. RLE-1CT at 25:3-14.

that could never exist because there was no underlying transaction. There was no separate pot of "balancing adjustment costs" that could have been charged to Oregon or Utah. There was only the single pot of actual, system-wide market purchase costs, which was properly allocated across all six states, with Washington's share being trued-up by the balancing adjustment to reflect its total consumption. Our response was not an admission of incompetence; it was an attempt to explain that Public Counsel is asking us to prove a negative about a fictional event. The claim that this "calls into question all of the charges"[110] is a dramatic leap in logic based on their initial misunderstanding. Our cost tracking and allocation systems are robust and are the very systems that allow us to perform these precise calculations in the first place.

ii. The Historical Context: An Established and Agreed-Upon Methodology

Q. History is important. Has this balancing adjustment process been in place for a long time? And was Public Counsel aware of how it worked before they filed this testimony?

A. Yes, this is a critically important part of the context. This is not a new or hidden process. The WIJAM, including this specific balancing adjustment mechanism, has been used to calculate Washington's costs since calendar year 2021. Furthermore, Public Counsel was not only aware of this balancing adjustment, but they were a party and signatory to the agreement that put it in place.

The Company, Staff, Public Counsel, AWEC, and other parties engaged in extensive negotiations to develop the WIJAM. In the Company's GRC in Washington—Docket UE-191024—in December 2019, Company witness Michael G.

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[110] Earle, Exh. RLE-1CT at 25:13-14.

Wilding submitted detailed testimony explaining exactly how this process would work. His testimony stated, in part: "The energy from Washington's allocated share of resources and market transactions is then compared to . . . Washington's retail load, and to the extent a load and energy imbalance exists, the difference is accounted for by adjusting system balancing transactions volumes using the weighted average market price for the month."[111] This is a clear and unambiguous description of the balancing adjustment.

Following this, in July 2020, the parties in that case, including Public Counsel, filed joint testimony in support of a settlement. That joint testimony stated: "The Parties support and recommend the Commission adopt the WIJAM and the 2020 Protocol, which are discussed in the direct testimony of Ms. Etta Lockey and Mr. Wilding."[112] Public Counsel was a signatory to that stipulation.[113] This is a formal, on-the-record endorsement of the very methodology they now criticize. For Public Counsel to now claim this process is improper or leads to over-collections is a complete reversal of their prior, stipulated position.

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[111] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Wilding, Exh. MGW-1CT at 10:8-12 (Dec. 13, 2019).
[112] Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, UE-180778 (Consolidated), Parties, Exh. JT-1T at 15:2-6 (July 17, 2020).
[113] Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, UE-180778 (Consolidated), Settlement Stipulation at 20 (July 17, 2020).

Q. Public Counsel is arguing that the Company is over-collecting costs.[114] The Company explains that this adjustment is necessary to ensure Washington pays its fair share, that it is calculated using a reasonable method based on real market prices, and that it is part of a larger methodology that Public Counsel themselves reviewed and formally agreed to just a few years ago. Is that an accurate summary of the Company's position?

A. Yes. The entire claim of an "over-collection" of short-term firm purchase costs is built on a foundational error: confusing a non-cash ratemaking allocation with a real cash expenditure. Because this foundational premise is false, all of the conclusions and recommendations that Public Counsel builds upon it are also invalid. The balancing adjustment is not a tool for over-collection; it is a required tool for ensuring fairness and upholding the principle of cost causation. It is working exactly as it was designed and agreed to by all parties, including Public Counsel.

Q. Given this, what is your response to Public Counsel's recommendations? Specifically, why should this Commission not open an investigation, consider reparations, and reform the allocation process as they suggest?[115]

A. The Commission should reject all of Public Counsel's recommendations because they are remedies for a problem that does not exist.

First, there is no need for an investigation into an over-collection because, as we have demonstrated, no over-collection has occurred. The facts show that the Company has recovered only the costs it actually incurred. An investigation would expend significant time and resources from the Commission, its Staff, Public

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[114] Earle, Exh. RLE-1CT at 26:7-11.
[115] Earle, Exh. RLE-1CT at 27:3-28:2.

Counsel, and the Company to re-examine a settled and properly functioning accounting mechanism.

Second, because there has been no over-collection, there is no basis whatsoever for reparations. Washington customers have not been overcharged; they have been charged appropriate costs for the electricity they consumed, in accordance with a methodology that their own representatives in Public Counsel agreed was fair and reasonable.

Finally, the recommendation that "the allocation method for power costs be reformed so that over-collection does not occur"[116] is unnecessary. There is no need to reform the allocation process to prevent a problem that is not happening. The WIJAM's balancing adjustment is not a flaw in the system; it is a feature of the system. For all these reasons, we respectfully request that the Commission reject Public Counsel's position and recommendations in their entirety.

iii. "Market Exposure" under the 2026 Protocol

Q. Public Counsel also claims that the Company does not accurately depict Washington's market exposure under the new 2026 Protocol and that your statement that market exposure is "eliminate[d]" is not true.[117] Can you clarify this?

A. Yes. This is another instance of Public Counsel misinterpreting our testimony by taking a statement out of its specific and clearly defined context. In our direct testimony, we stated, "This is an elimination of market exposure *in the context of*

[116] Earle, Exh. RLE-1CT at 27:15-16.
[117] Earle, Exh. RLE-1CT at 14:5-12.

allocations and results in an allocated surplus of energy on a net annual basis."[118] The key phrase here is "in the context of allocations." We are describing a change in Washington's *ratemaking position*, not its day-to-day *operational position*.

This difference is key. A state's "ratemaking position" is an accounting concept. It is the result of comparing the amount of generation resources allocated to Washington in the cost allocation agreement with the amount of customer load in that state. Under the WIJAM, Washington was allocated fewer resources than its load, creating a "short" (energy shortfall) ratemaking position, which resulted in the balancing adjustment charge discussed above. Under the Washington 2026 Protocol as proposed by the Company, Washington will be allocated *more* resources than its load, creating a "long" or surplus ratemaking position. This change eliminates Washington's exposure to the financial risk of the balancing adjustment charge and, in fact, turns it into a credit.

An "operational position," on the other hand, refers to the real-time physical and financial actions the Company takes to balance the entire six-state grid. This includes buying and selling power in various markets—forward, day-ahead, and real-time—to manage fluctuations in supply and demand. Every utility, regardless of its ratemaking position, must engage in these market transactions to ensure the lights stay on. Public Counsel incorrectly mixes these two separate concepts. They take Washington's new "long" ratemaking position and subtract our system's normal operational market purchases, resulting in a meaningless number that they then label as a "short" position. This is an apples-to-oranges comparison. Our statement was,

[118] Mitchell, Exh. RJM-1CT at 14:15-23.

and remains, factually correct within the specific ratemaking context it was made. The 2026 Protocol is beneficial for Washington customers precisely because it moves them from a deficit to a surplus position for allocation purposes, thereby eliminating the financial risk associated with the historical balancing adjustment charge.

10. AWEC – Industrial Contracts

i. Defining Mandatory Contingency Reserves and Curtailable Load

Q. Please summarize AWEC's concern regarding industrial curtailment contracts.

A. The Company includes in its forecast in this proceeding the costs incurred through two interruptible curtailment contracts with industrial customers in other states. AWEC recommends that the costs of those contracts be removed from this PCORC because Washington did not approve the contracts and "there is no clear way to allocate the costs and benefits of those contracts to Washington rates."[119]

Q. Notwithstanding the fact that these contracts were executed with specific curtailable industrial load in other states, do these interruptible curtailment contracts provide benefits to Washington customers?

A. Yes. These contracts provide mandatory contingency reserves, which help the Company balance generation and customers' load in its balancing authority areas, enable the reliable interconnection of renewable resources, and benefit Washington customers.

[119] Mullins, Exh. BGM-1CT at 73:10-18.

Q. To provide additional context for the need to balance generation and customer usage, can you explain again what happens if that perfect balance is not maintained at every single moment?

A. The consequences of an imbalance are immediate and severe. It is helpful to think of the electric grid as a large reservoir of water where the water level represents the grid's stability. Our job is to keep that water level perfectly constant. If customers start using more electricity than is being generated, it is like more water flowing out of the reservoir than is flowing in. The water level, or grid stability, drops. If it drops too far, the system becomes unstable, leading to blackouts. Conversely, if we generate more electricity than customers are using, it is like water overflowing the reservoir. This can damage customer equipment and utility infrastructure. Therefore, maintaining this perfect balance is the most critical task for ensuring the lights stay on reliably for everyone.

Q. How does the Company ensure this perfect balance is maintained to prevent such problems?

A. We maintain this balance by having access to "operating reserves." These are resources that act as our safety net or insurance policy for the grid. Operating reserves are sources of electricity generation, or reductions in electricity use, that are on standby and can be called upon instantly to correct any unforeseen imbalance. Whether a large power plant unexpectedly shuts down or the wind generation deviates from our expectations, these reserves are what allow us to quickly restore the balance and prevent a small problem from turning into a widespread outage.

Q. Earlier in this testimony you mentioned the importance of regulation reserves. Are there different types of reserves for different kinds of problems on the grid?

A. Yes. We use different types of reserves for different situations. As mentioned prior, for the small, moment-to-moment fluctuations that happen throughout the day (e.g., with wind generation), we use what are called regulation reserves. However, for large, sudden, and unexpected emergencies, we must have a more powerful type of reserve available. These are called contingency reserves. A contingency (emergency condition) is an unexpected failure of a major component of the power system, such as the sudden and unforeseen shutdown of a generating plant, as mentioned above, or the failure of a major transmission line. Contingency reserves are the fast-acting resources we deploy immediately following such an event to prevent the grid from becoming unstable.

Q. Who decides how much contingency reserves the Company is required to have available?

A. That decision is not left to us; it is a mandatory requirement set by a national authority. The North American Electric Reliability Corporation, or NERC, is the organization certified by the federal government to ensure the reliability of the entire North American power grid. NERC establishes and enforces mandatory reliability standards that all utilities, including the Company, must follow. The specific rulebook for this is reliability standard BAL-002-WECC-3. This standard dictates the minimum amount of contingency reserves we must have available at all times. The requirement is generally an amount equal to 3 percent of our customer demand plus three percent of our generation. Holding these reserves is not optional; it is a fundamental requirement for the reliable operation of the grid.

Q. How does a contract with an industrial customer, like the two that AWEC has identified,[120] function as one of these mandatory contingency reserves?

A. This is a key aspect of modern grid management. These contracts are for what is known as "curtailable load." From the perspective of the electric grid, reducing electricity demand is identical to increasing electricity supply. When we ask one of these large industrial customers to reduce their electricity use under the terms of their contract, that customer's demand for power is instantly removed from the system. This frees up that electricity to serve other customers, having the exact same stabilizing effect as if we had turned on a brand-new power plant of the same size. NERC's reliability standards explicitly recognize this, defining "Interruptible Load or Interruptible Demand" as a valid and essential resource for providing contingency reserves.[121]

Q. So, to be clear, when these industrial customers are asked to reduce their power use, they are essentially acting like a power plant that instantly comes online to help the grid?

A. Yes. They are a critical reliability resource. A major advantage of using curtailable industrial load for contingency reserves is its speed. These resources can reduce their consumption within minutes of being requested, which is the rapid response time needed to stabilize the grid after a major contingency event. This makes them an extremely valuable and effective tool for meeting our mandatory reliability obligations.

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[120] Mullins, Exh. BGM-1CT at 73:12-13.
[121] NERC Reliability Standard BAL-002-WECC-3, B.R1.1.2.

Q. How much of this specific type of reserve do these two industrial contracts provide to the system?

A. Together, these two contracts provide over 100 MW of operating reserve capacity for the Company's system. Specifically, this capacity is primarily designated as contingency reserves, meaning it is held to ensure we can comply with the mandatory requirements of NERC Reliability Standard BAL-002-WECC-3. This is not a small amount; it is a significant and essential component of our portfolio of reliability resources.

Q. Why are these fast-acting reserves, like the ones provided by the industrial contracts, becoming more important for the electric grid now?

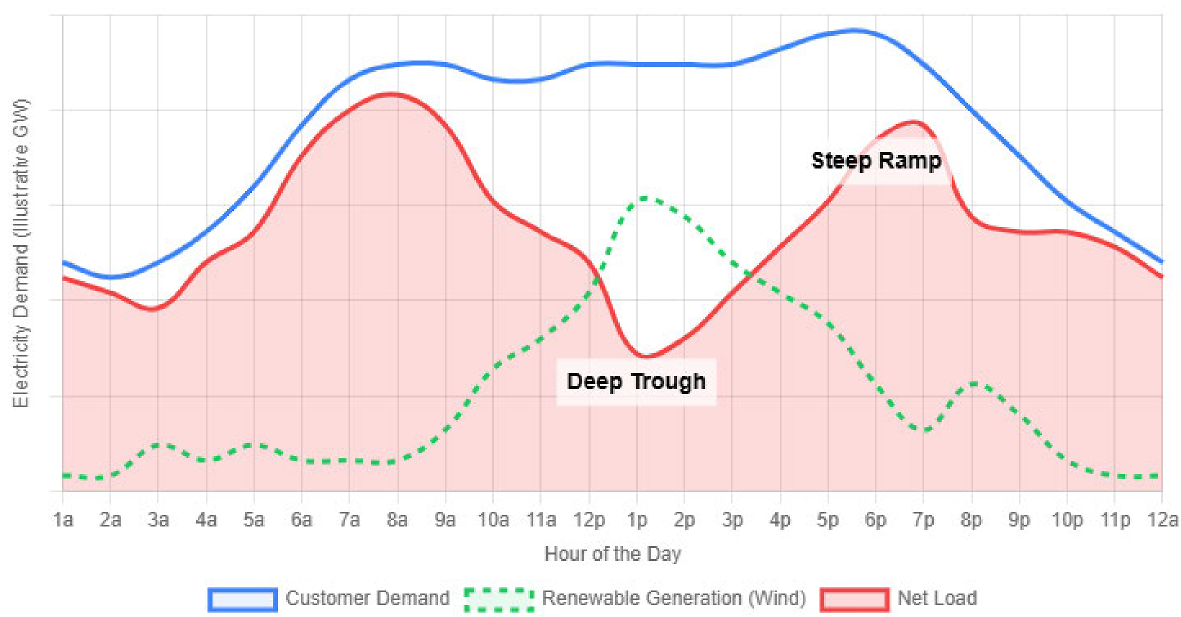
A. These reserves are becoming more critical because the nature of our electricity supply is changing. Historically, most electricity came from traditional power plants, like coal, natural gas, and large hydroelectric dams, which provide a very steady and predictable supply of power. Today, a growing portion of our energy, particularly in Washington, comes from variable renewable resources like wind and solar. While these resources are clean and essential for our future, their output is not constant. It fluctuates with the weather—when the wind blows and when the sun shines. This variability introduces more uncertainty and volatility to the grid, which requires a larger safety net of fast-acting reserves to manage emergency conditions.

Q. Could you provide an illustration to help demonstrate how the variable nature of wind and solar power creates a greater need for resources like these industrial contracts?

A. Certainly. A visual representation can make this concept much clearer. Please consider the following visual, which shows the challenge of balancing a modern electric grid.

Load net Wind Profile

This chart illustrates how wind generation can impact the grid on a typical winter day. The variability in wind generation often creates deep troughs in net load (load less wind) that must be managed by dispatchable resources.



Customer Demand
Total electricity use. In winter, demand often peaks in the early morning and again in the evening as people heat their homes.

Renewable Generation
Wind power is variable. On this day, it peaks midday, significantly reducing the need for traditional power resources.

Net Load
This is the amount of power that controllable resources must provide. The key challenge is the steep ramp from troughs to peaks.

As the diagram illustrates, customer demand for electricity, shown by the blue line, follows a relatively smooth and predictable pattern throughout the day. However, the output from wind resources, shown by the dashed green line, is much more variable and difficult to predict. The bold red line represents “net load.” This is the amount of electricity that our dispatchable power resources must provide to fill the gap between what customers need and what renewables are producing. As you can see, the red line has much steeper and more rapid changes than the customer demand line alone. It is precisely to manage contingencies (emergency conditions) during these sharp, sudden ramps up and down in the net load—that already stretch the limits of dispatchable power plants—that we need fast-acting reserves like the curtailable load from the industrial contracts. They are the tool that allows us to follow that volatile red line *while simultaneously* keeping the system in perfect balance under emergency conditions.

Q. Is it accurate to say that without the over 100 MW of operating reserves from these contracts, it would be difficult to reliably integrate all of Washington's allocated generation portfolio onto the grid?

A. It is more than difficult; it would be impossible to do so while maintaining the mandatory reliability standards set by NERC. The totality of Washington's generation portfolio cannot be integrated onto the system without this curtailable industrial capacity. Crucially, this industrial capacity supports not just PACE resources but also PacifiCorp West (PACW) (i.e., PacifiCorp's western balancing authority area) resources, through reservation of dedicated capacity on Company transmission rights from PACE to PACW. Adding large amounts of generation to the grid without having sufficient fast-acting reserves as backup during emergency conditions would be like adding hundreds of crash-prone cars to a highway system that has no emergency lanes or shoulders. It would create instability and dramatically increase the risk of system-wide failures. These contracts provide the essential stability services that make Washington's generation portfolio a reliable source of energy for customers.

Q. What would be the direct consequence for Washington customers if these contracts were removed from rates, as AWEC suggests,[122] in terms of the state's generation portfolio?

A. If the costs for these contracts—which represent payments for essential reliability services needed to support Washington's generation portfolio—are removed from Washington rates, then a commensurate amount of that generation portfolio which depends on this service also must be removed. The Company cannot reliably support a generation portfolio which lacks the required amount of dispatchable resources. To be in that position would be a violation of mandatory NERC reliability standards and would jeopardize service for Washington customers.

ii. Applying the Cost Causation Principle to Washington Rates

Q. AWEC claims that "there is no clear way to allocate the costs and benefits of those contracts to Washington rates."[123] From a utility regulation perspective, is this a valid argument?

A. No, it is not a valid argument. In fact, it contradicts one of the most fundamental and long-standing principles of public utility ratemaking. As discussed above, a fundamental ratemaking principle is that customers must pay for benefits received, consistent with cost causation. This means that the costs of providing a service should be paid by the customers who cause those costs to be incurred and who receive the benefits of that service.

[122] Mullins, Exh. BGM-1CT at 73:17-18.
[123] Mullins, Exh. BGM-1CT at 73:16-17.

Q. How does the Company apply that "beneficiary pays" principle to determine which customers should pay for a system-wide reliability resource like those industrial customers' curtailable load?

A. We apply it by identifying the direct link between a customer group's generation portfolio and the need for a specific reliability service. While it is true that all customers on our integrated system benefit from a reliable grid, a specific and identifiable benefit is provided to those customers whose generation portfolio *creates* the need for a particular type of reserve. As we have established, the generation portfolio of resources allocated to Washington creates a need for fast-acting contingency reserves to ensure that energy can be delivered reliably.

Q. So, because Washington customers receive electricity from a generation portfolio that depends on these contingency reserves held on curtailable industrial load, do Washington customers directly cause the need for and benefit from these contracts?

A. Yes. The causal link is direct and unambiguous. Washington customers are the beneficiaries of an allocation of energy (generation portfolio). The physical nature of that generation portfolio directly causes a need for the exact type of fast-acting contingency reserves that these two industrial contracts provide. Therefore, under the foundational principle of cost causation, Washington customers are clear beneficiaries of the reliability service these contracts provide, and it is appropriate and just for them to bear the associated costs.

Q. What is the fundamental flaw in AWEC's proposal to remove the costs of these contracts from Washington rates while simultaneously expecting Washington to keep the benefits of its generation portfolio that is supported by them?

A. The fundamental flaw is that AWEC is seeking to receive benefits without acknowledging the commensurate costs required to produce those benefits. This proposal would allow Washington customers to enjoy the full advantages of their generation portfolio while shifting the necessary and unavoidable costs of making that portfolio reliable onto others. This is the very definition of an inequitable cost shift, which runs contrary to the principles of fair ratemaking.

Q. What is the Company's recommendation to the Commission regarding AWEC's recommendation to remove the costs of these industrial curtailment contracts from Washington rates?

A. The Company recommends that the Commission reject AWEC's position and its recommendation in their entirety. AWEC's stance is based on the false premise that there is no clear way to allocate these costs, when in fact, the well-established regulatory principle of cost causation provides a clear and direct path. These contracts provide essential contingency reserves that are required to reliably integrate Washington's generation portfolio. The costs are therefore directly caused by and directly benefit Washington customers. Approving AWEC's recommendation would be unjust, would violate foundational ratemaking principles, and would ultimately undermine Washington's ability to achieve its clean energy goals while maintaining the reliable electric service its citizens expect and deserve. The costs for these contracts are properly allocated to Washington and should remain in Washington rates.

11. AWEC – Production Tax Credit Rates

Q. Is there an update to the projected 2026 federal production tax credit (PTC) rate?

A. Yes. As explained in the Company's response to AWEC Data Request 017,[124] the forecast 2026 PTC rate used in the Company's direct testimony was 3.0 cents per kilowatt-hour (cents/kWh) for all of the Company's qualified wind facilities. Based on currently available data, the Company's best estimate of the 2026 PTC rate is 3.0 cents/kWh for qualified wind facilities placed in service after December 31, 2021, and before January 1, 2025, and 3.1 cents/kWh for all other qualified wind facilities.

Q. Did AWEC properly update the projected 2026 PTC rate in Response Testimony?

A. No. Despite acknowledging the projected 2026 PTC rate for the Company's qualified wind facilities placed in service after December 31, 2021, and before January 1, 2025, is 3.0 cents/kWh as described in the Company's response to AWEC Data Request 017, due to what AWEC describes as a "slightly different formula," AWEC erroneously recommends the use of a higher PTC rate without justification or explanation.[125] In other words, AWEC does not dispute that certain wind facilities will only be eligible for a PTC rate of 3.0 cents/kWh but AWEC recommends applying a PTC rate of 3.1 cents/kWh for those qualified wind facilities. The

[124] Mullins, Exh. BGM-3 at 8.
[125] Mullins, Exh. BGM-1CT at 80:1-4.

Commission should: (1) reject this clearly erroneous application;[126] and (2) affirm the Company's PTC rates—as presented on page 8 of Exhibit BGM-3—which will be updated as part of the update to electricity prices in the upcoming compliance filing.

12. <u>AWEC – BP-26 Rate Case</u>

Q. AWEC raises an issue regarding the Bonneville Power Administration, or BPA, rate case.[127] Can you first explain what BPA is and confirm if their rates did, in fact, go up?

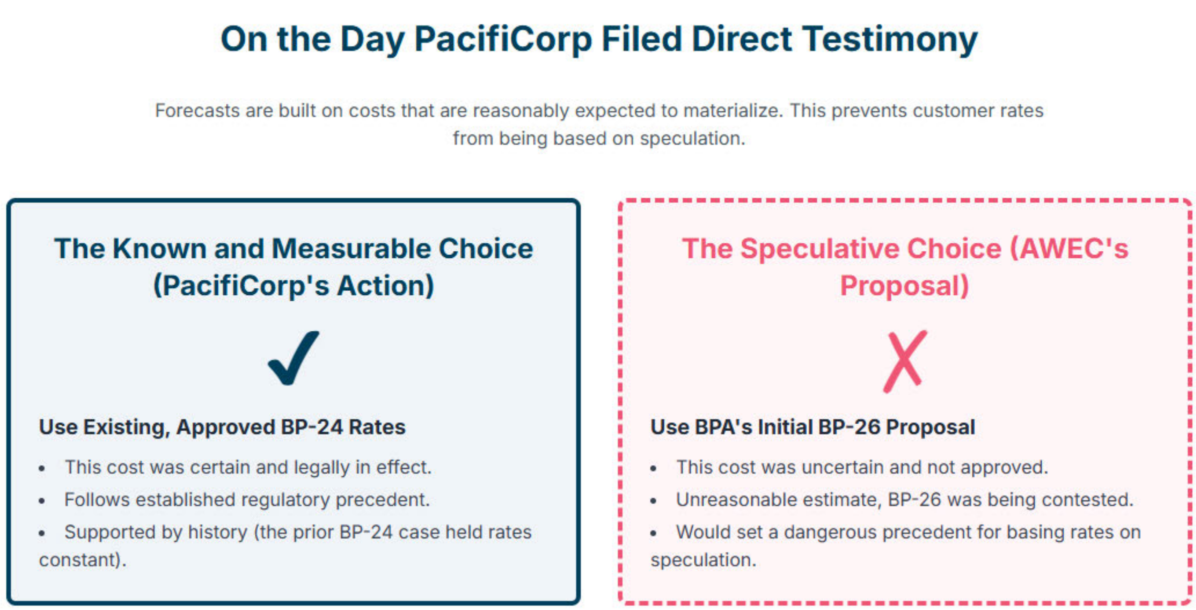
A. Certainly. The Bonneville Power Administration, or BPA, is a federal agency that owns and operates a very large portion of the high-voltage transmission system in the Pacific Northwest. BPA goes through its own separate and formal rate-setting process to determine the rates it will charge. It is true that BPA recently concluded its rate case for the 2026 period, known as the "BP-26" rate case. In its final decision, BPA approved an increase to its transmission rates. This is a real cost that the Company will incur.

Q. AWEC claims in its testimony that the Company knew the "magnitude of the rate increase" from BPA's "initial proposal."[128] If you knew this cost was coming, why was an estimate for it not included in your initial filing?

A. This is the most critical point of disagreement. An "initial proposal" in a complex rate case like BPA's is not a final cost; it is a starting point for negotiation and litigation. The BPA rate process is a lengthy, formal proceeding that involves many different parties, expert testimony, hearings, and the potential for settlements that can change

[126] Mullins, Exh. BGM-1CT at 80:6-7.
[127] Mullins, Exh. BGM-1CT at 45:8-46:8.
[128] Mullins, Exh. BGM-1CT at 45:14-15.

the final numbers. The rates in BPA's initial proposal can, and often do, change before BPA issues its Final Record of Decision. This process is similar to the process in this PCORC. The rates in the Company's direct testimony (initial proposal) can, and often do, change before the Commission issues its final order. The Company did not include the proposed BP-26 rates from BPA's initial proposal because they were unreasonably speculative at the time of our filing. Put simply, the BPA rates are not the result of a simulation model, and the final rates were not known and measurable at the time of filing. For the very same reason that the Company was not allowed to assess Washington customers the rates from the Company's direct testimony; it would not have been appropriate for us to include a number from BPA's preliminary proposal. The only proper course of action was to use the rates that were currently known.



Q. What is the Company's recommendation on this BPA rate case issue?

A. In isolation, including the updated BPA rates in the compliance filing would result in a more accurate NPC forecast **on a single line-item basis**. However, the purpose of a narrow compliance filing update is to limit the scope of change to the fundamentals of the system (e.g., market prices). Within the Company's wheeling expenses, there are other outdated items apart from BPA rates, some of these outdated items would increase NPC if updated and some would decrease NPC if updated. Regardless, **the Company's recommendation** in this case is to maintain our uncontested, proposed compliance filing updates from direct testimony, and **not adopt AWEC's recommendation**. The proposed compliance filing updates, from direct testimony, include forward prices for natural gas and electricity, hedging positions, and new power purchase agreements.[129]

13. AWEC – BPA Real Power Losses

Q. AWEC recommends removing a wheeling cost called "BPA real power losses" from the NPC forecast?[130] Has the Company already accepted AWEC's recommendation in another proceeding?

A. Yes. In Public Utility Commission of Oregon docket UE 450, the Company's Oregon Transmission Adjustment Mechanism filing, the Company accepted this change to its NPC forecast.

Q. What factors should the Commission consider when evaluating AWEC's recommendation?

A. The Commission should evaluate this recommendation based on its consistency with the goal of NPC forecast accuracy. Removing the wheeling charge for BPA real power losses based on AWEC's recommendation meets the criteria. It corrects an

[129] Mitchell, Exh. RJM-1CT at 8:1-10.
[130] Mullins, Exh. BGM-1CT at 44:7-10.

error which eliminates double-counting, and results in a more accurate and equitable forecast.

Including this separate wheeling expense line item is like buying a product online where the total cost already includes a "Shipping & Handling" fee, but then seeing an additional, separate line item added at the very end labeled "Postage Cost." You are being asked to pay twice for the exact same delivery service. Removing this line item corrects that double-billing error.

Therefore, the Company recommends that the Commission adopt AWEC's BPA real power losses recommendation to remove the BPA real power losses wheeling expense line item from the NPC forecast.

14. STAFF, AWEC, and PUBLIC COUNSEL – CETA Market Premium

Q. Please summarize the 50 percent CETA adder that the parties discuss in their testimonies.

A. In the Company's direct filing, the Company discussed the need to execute custom, CETA-compliant hedges since the unspecified quarterly blocks typically offered in the forward markets did not comply with CETA. To address the uncertainty as to the likely premium for a CETA-compliant product, the Company selected a conservative premium of 50 percent on top of the costs of traditional quarterly power hedge blocks and applied that premium to all forward transactions in the NPC forecast.[131] As noted in my direct testimony, at that time the Washington state legislature was considering two bills that would allow for non-CETA compliant (unspecified) quarterly energy products to be allowed in customer rates, but those bills had not yet passed.[132]

[131] Mitchell, Exh. RJM-1CT at 11:6-20.
[132] Mitchell, Exh. RJM-1CT at 12:1-4.

Q. Did parties to this docket discuss the 50 percent adder in their testimony?

A. Yes. AWEC, Staff, and Public Counsel all recommend removing this adder now that House Bill (HB) 1329 allows unspecified energy, purchased in quarterly blocks, to serve Washington customers.[133]

Q. Has the Company already proposed to remove this adder?

A. Yes. In direct testimony the Company stated: "If the law is changed to allow a portion of unspecified quarterly energy products in rates (as currently contemplated by the bills), then the Company proposes that the 50 percent premium on supply risk (resource adequacy) hedges be re-evaluated since those types of hedges, under certain conditions, can be unspecified."[134] Consistent with this testimony and the passage of HB 1329, the Company agrees that the adder should be removed.

III. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. The Company respectfully recommends that the Commission affirm the Company's NPC forecasting approach and reject proposals that would fragment or distort it. Specifically: (1) deny AWEC's request to update the Aurora model's major version in the narrow compliance-filing scope and preserve the Commission's long-standing practice of limiting compliance updates to specified input values; (2) approve the Company's forward market transaction modeling adjustment as a prudent and necessary recognition of real-world hedging / risk management transaction costs and reject both Staff's "net transaction" theory and AWEC's related criticisms, while continuing to account for Washington's separate hedge book; (3) remove the now-

[133] Mullins, Exh. BGM-1CT at 51:15-52:2; Wilson, Exh. JDW-1T at 12:1-2; Earle, Exh. RLE-1CT at 18:15-16.
[134] Mitchell, Exh. RJM-1CT at 12:6-10.

obsolete 50 percent CETA adder in light of House Bill 1329 so that modeled prices reflect the lawful, quarter-block hedging instruments the Company can actually procure; (4) uphold the Company's wind and transmission modeling grounded in security-constrained, least-cost economic dispatch and reject the claim that the Company applies any "wind production penalty," including rejecting proposals to model physically impossible "must-run" operation; (5) recognize the prudence of the NPM through April 2026 as a tool that has lowered actual NPC and prepared the Company for EDAM participation; (6) acknowledge FERC's direction to reclassify certain allowance costs to Account 509 as a neutral accounting update that does not change this forecast, and that will be examined in the PCAM; (7) reject Public Counsel's short-term firm "double-collection" allegation by recognizing the WIJAM balancing adjustment as a spreadsheet based, ratemaking, monetary valuation; (8) retain in Washington rates the costs of the two curtailable industrial contracts that provide contingency reserves essential to integrating Washington's generation portfolio, because the contracts directly benefit Washington customers; (9) adopt AWEC's specific correction to remove the duplicative BPA real-power-loss wheeling line item from the NPC forecast; (10) decline to inject, mid-proceeding, BPA BP-26 transmission cost increases into this forecast, outside the limited scope of compliance updates, reserving such changes for the proper future proceeding; and (11) reject AWEC's erroneous application of PTC rates, and affirm the Company's position and associated compliance filing update.

Q. Does this conclude your rebuttal testimony?

A. Yes.