Exh. IZ-DM-1T
Docket UE-25_____
Witness: Isaiah M.R. Zacharia
Witness: Daniel J. MacNeil

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-25_____

PACIFICORP

DIRECT TESTIMONY OF ISAIAH M.R. ZACHARIA AND DANIEL J. MACNEIL

April 2025

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Q. Please state your names, business addresses, and current positions with PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company).

A. My name is Isaiah M.R. Zacharia, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Senior Net Power Cost Analyst and I am testifying on behalf of PacifiCorp.

My name is Daniel J. MacNeil and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Commercial Analytics Adviser and I am testifying on behalf of PacifiCorp.

I. QUALIFICATIONS

Q. Company witness Zacharia, please describe your education and professional experience.

A. I received a Bachelor of Science degree from Portland State University. I have been employed by PacifiCorp since 2022 as a member of the regulatory net power costs group.

Q. Company witness Zacharia, have you testified in a previous regulatory proceeding?

A. Yes. I have previously provided testimony to the Washington Utilities and Transportation Commission (Commission).

Q. Company witness MacNeil, please describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining PacifiCorp, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by PacifiCorp since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to PacifiCorp's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in PacifiCorp's jurisdictions.

Q. Company witness MacNeil, have you testified in a previous regulatory proceedings?

A. Yes. While this is my first time providing testimony to the Washington Utilities and Transportation Commission (Commission), I have previously provided testimony in California, Idaho, Oregon, Utah, Wyoming, and Federal Energy Regulatory Commission dockets.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. This testimony presents a counterfactual 10-year historical analysis and 10-year forecasted analysis of Washington's net power costs (NPC). This analysis considers an alternative scenario where Washington's Washington Inter-Jurisdictional Allocation Methodology (WIJAM) energy deficit (short) position is closed using energy from Washington-allocated generation resources instead of market transactions, as requested by the Commission in the Final Order from the 2022 Power Cost Adjustment Mechanism (PCAM).[1]

[1] *In the Matter of PacifiCorp d/b/a Pacific Power & Light Company, 2022 PCAM Annual Report*, Docket No. UE-230482, Order 07 at ¶ 137 (Oct. 30, 2024).

Q. What did the Commission require in the Final Order from 2022 PCAM?

A. The Commission identified the following requirement for a future filing:

> In the future, PacifiCorp must show analysis of the alternative, showing what rates for Washington customers would have been in the preceding 10 years if PacifiCorp had closed Washington's position with generation resources on its system rather than market positions, and a cost benefit analysis showing what rates will be 10 years into the future using Washington-based generation resources versus market position.[2]

III. 10-YEAR HISTORICAL ANALYSIS

Q. Can you describe the counterfactual analysis?

A. This counterfactual analysis explores an alternative scenario, using historical actual NPC, where at least 75 percent of Washington's maximum monthly "short position" is met through long-term contracted resources instead of market transactions. This approach includes a four-year delay between the occurrence of the short position and the online date of the generating resource(s). The historical maximum monthly "short positions" are based on the West Control Area Inter-Jurisdictional Allocation Methodology (WCA) from 2015 to 2020 and the WIJAM from 2021 through 2024.

Q. Please briefly explain what Washington's maximum "short position" means.

A. Washington's maximum "short position" refers to the maximum difference between Washington customers energy obligations and their allocated purchases, sales and generation. Both the WCA and the WIJAM include a "Net Position Balancing" component, which ensures that Washington's energy requirements are met, with no resulting deficit or surplus. The "Net Position Balancing" was used to determine the maximum monthly "short position" for each year under the WCA and WIJAM in this analysis.

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[2] *Id.*

Q. Please explain why only 75 percent of the maximum "short position" was met with generation resources in this counterfactual analysis.

A. The analysis assumes that only 75 percent of the maximum "short position" was met with long-term contracted resource generation to keep a measure of consistency with the Company's prevailing hedging policy, which ensures 75 percent of the maximum position from a month in each quarter of the year is secured in the forward markets. Table 1 below shows what 75 percent of Washington's maximum "short position" was from each year under the WCA or WIJAM in megawatt-hours (MWhs).

Table 1. Washington Long (Short) Position over Time

75% of Maximum Position Long (Short)		
Year	**Month**	**MWhs**
2015	12	(22,936)
2016	11	(23,275)
2017	12	5,136
2018	12	(25,139)
2019	2	(22,084)
2020	12	(38,692)
2021	12	(139,757)
2022	1	(139,784)
2023	2	(93,116)
2024	1	(94,020)

Q. Please explain the delay between the closing/meeting the maximum "short position" and the resource's commercial operation date.

A. A four-year delay occurs between meeting the maximum "short position" and a resource's commercial operation date because the Company cannot determine the actual maximum "short position" calculated in the WCA or WIJAM until the respective calendar year is complete. For example, the Company would not know the maximum "short position" in calendar year 2015 until the second quarter of calendar year 2016. Once the maximum "short position" was determined, the Company then would have begun the process of acquiring resources. This process, for the purposes of this alternative analysis, is estimated to take an additional three calendar years.[3]

Q. Please explain the resource types selected for this analysis.

A. For the purposes of this counterfactual analysis, the Company picked a 50/50 capacity split of wind and solar generation resources. The Company's portfolio has included both wind and solar resources for more than ten years, and both resource types have been identified as cost-effective resource options by their inclusion in each of the Company's Integrated Resource Plan (IRP) preferred portfolios since the 2017 IRP. Wind and solar resources are dependent on different weather conditions, and diversity in their expected output reduces the amount of variation in output over time. For example, wind generation at night helps offset the absence of solar generation, and solar generation on calm days helps offset the absence of wind generation.

Q. Please explain the pricing of the counterfactual resources.

A. The counterfactual resources are priced at the same price ($/MWh) as resources that came online consistent with when these counterfactual resources were placed into the study. Additionally, as these are wind and solar resources, the Schedule 3/3A Uncommitted Wind and Solar Open Access Transmission Tariff (OATT) rates, provided in Table 2, are added to the counterfactual contract price. The Schedule 3/3A costs can be seen in Table 3 and contract prices for the wind and solar resources can be seen in Table 4 below.

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[3] Three calendar years were determined to be the appropriate delay based off historical timelines associated with actual deals signed by the Company.

Table 2. PacifiCorp OATT Uncommitted Wind and Solar Rates

Schedule 3/3A Uncommitted $/MW-Year		
Year	Wind	Solar
2018-2020	$6,593.0	$6,593.0
2021-Forward	6,692.2	$5,583.6

Table 3. Annual Cost of OATT Schedule 3/3A

Schedule 3/3A Uncommitted $/Year			
Year	Wind	Solar OR	Solar UT
2019	$ 494,475	$ -	$ 494,475
2020	$ 494,475	$ -	$ 494,475
2021	$ 501,915	$ -	$ 418,770
2022	$ 501,915	$ -	$ 418,770
2023	$ 501,915	$ -	$ 418,770
2024	$ 803,064	$ 111,672	$ 558,360

Table 4. Wind and Solar Contract Prices

		Wind and Solar Contract Prices ($/MWh)					
Year Online	Fuel	2019	2020	2021	2022	2023	2024
2019	Wind	$ 58.96	$ 58.28	$ 60.97	$ 65.15	$ 67.43	$ 66.91
2021	Wind			$ 34.01	$ 36.78	$ 39.57	$ 78.18
2024	Wind						$ 45.00
2019	Solar UT	$ 46.24	$ 46.24	$ 46.24	$ 46.24	$ 46.24	$ 46.24
2021	Solar UT			$ 31.28	$ 31.28	$ 31.28	$ 31.28
2024	Solar UT						$ 29.45
2024	Solar OR						$ 35.98

Q. Explain the capacity assumptions used for this counterfactual analysis.

A. The wind and solar capacities assumed are provided in Table 5 below. The capacities were then multiplied by monthly capacity factors (which were taken from actual resources on the Company's system) and the number of hours in each respective month to calculate a monthly generation total for each respective resource. The generation at the monthly granularity was used to then ensure that the resources were meeting at least 75 percent of the maximum "short position" from four years ago.

Table 5. Counterfactual Analysis Resource Assumptions

	Resource Capacity (MW)		
Year	**Wind**	**Solar OR**	**Solar UT**
2019	75	0	75
2020	75	0	75
2021	75	0	75
2022	75	0	75
2023	75	0	75
2024	120	20	100

Q. Please summarize the results of this counterfactual analysis.

A. As can be seen in Figure 1 (Dollars) and Figure 2 (Washington allocated $/MWh), acquiring more generation resources at the above noted price assumptions results in a higher NPC in calendar years 2019, 2020, and 2021 and a lower NPC in calendar years 2022, 2023, and also a lower NPC in calendar year 2024 using preliminary data.

Figure 1. Results of Counterfactual Analysis (Dollars)

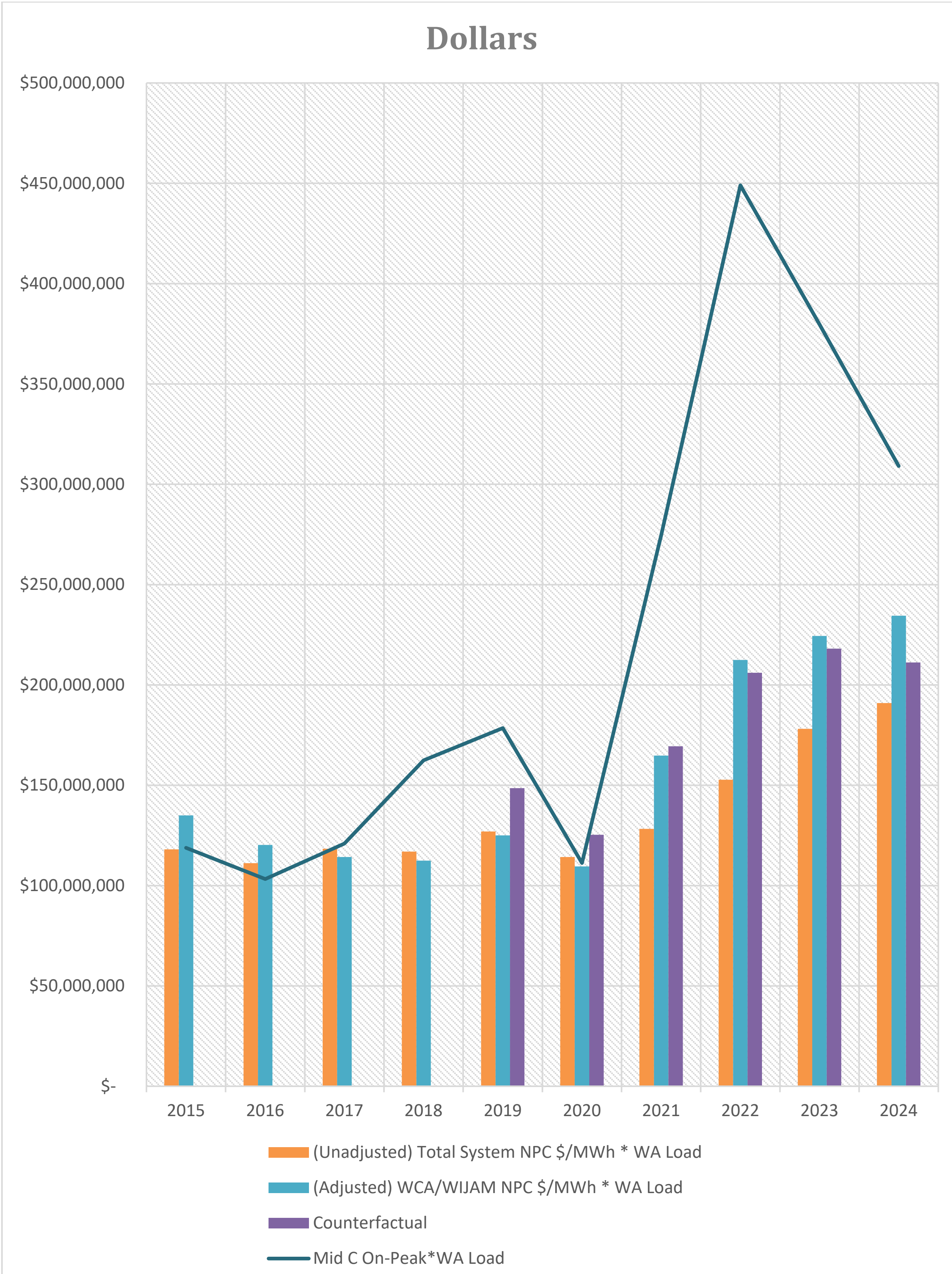
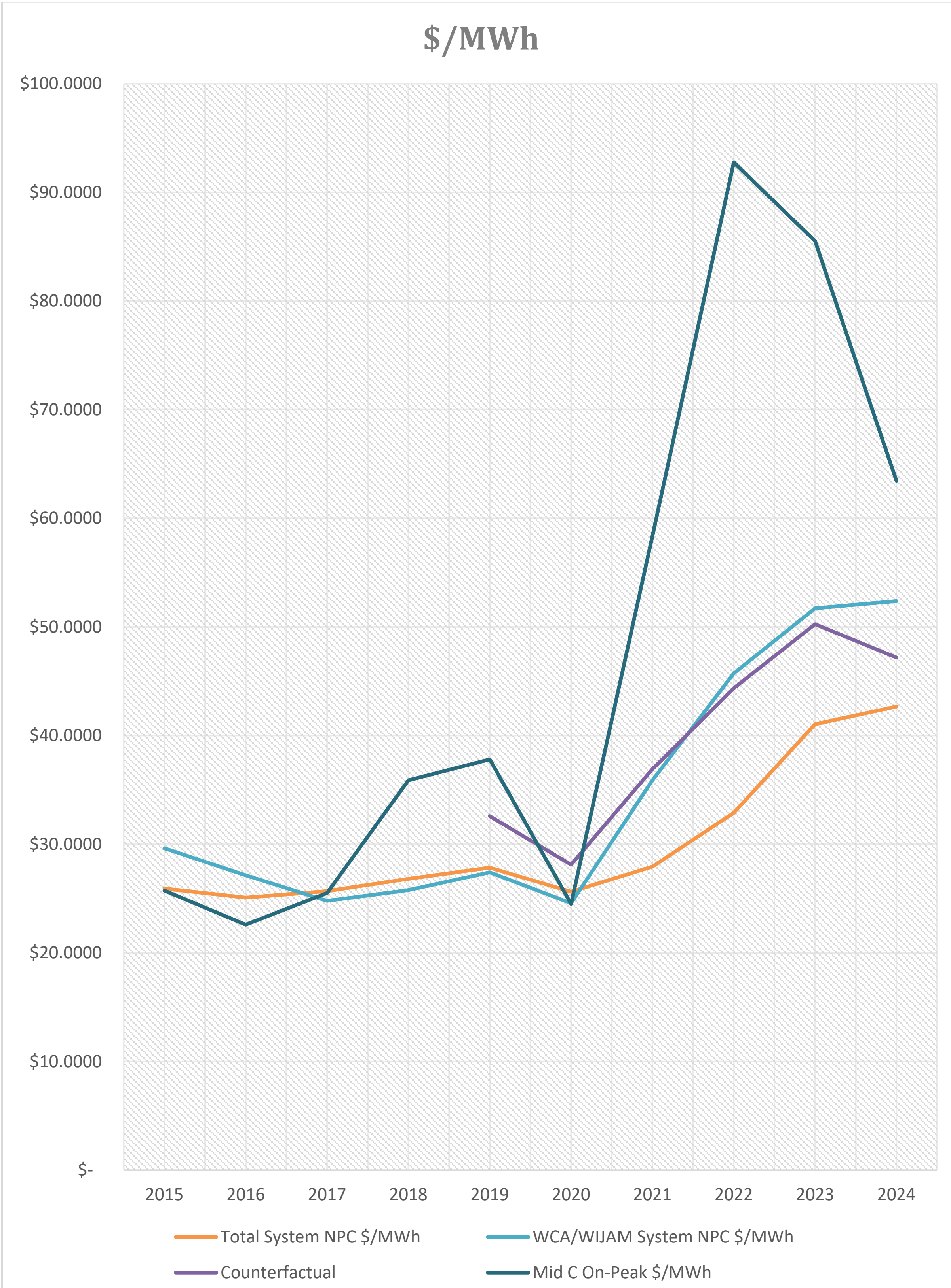


Figure 2. Results of Counterfactual Analysis ($/MWh)



Q. Please provide a narrative description for the counterfactual analysis.

A. As can be seen in Figure 1 above:

- The "(Unadjusted) Total System NPC $/MWh * WA Load" bars represent what Washington Net Power Costs would have been if Washington had participated in the 2020 Multi State Protocol (MSP) for the entirety of the historical period. This bar provides the lowest actual net power costs for Washington Customers in every year except for calendar years 2017, 2018, 2019, and 2020. The total system features the most diversity across resource types and locations which help to drive a hypothetical Washington portion of these NPC down. The complete resource diversity does include associated base rate components which are not analyzed in this counterfactual.

- The "(Adjusted) WCA/WIJAM NPC $/MWh * WA Load" bars represent the actual NPC for each calendar year allocated to Washington. The 2024 actuals featured in this line are unadjusted and preliminary.

- The "Mid C On-Peak * WA Load" line represents what Washington NPC would have been if the monthly Washington energy obligations were priced completely at the actual Mid-Columbia monthly on-peak price.

- The "Counterfactual" bars show what Washington NPC would have been if the Company had acquired contracted generation starting in calendar year 2019 to meet 75 percent of Washington's maximum short position in 2015 as previously described. As was explained above, the results of this counterfactual provide lower Washington net power costs in 2022, 2023, and 2024, driven by the higher power prices being replaced with lower contract prices.

Q. Please describe the issues with the counterfactual analysis.

A. There are several issues which are important to consider when reviewing the provided analysis. These issues which are discussed in more detail later in this testimony include the following:

- Re-dispatch of the Company's system to account for the counterfactual resources.

- Additional transmission lines required to connect counterfactual resources.

- Additional dispatchable resources may have been required to integrate these resources.

- The prices identified for each resource may be lower than the price at which the Company would have been able to contract.

- These resources would have been contracted over a 20-30 year period and this analysis only looks at a small portion of that timeline.

Company witness MacNeil reviews the economics of these resources in the 10-year forecast portion of the testimony below.

Q. Please explain why the intra-hourly dispatch of the system would have been different, had these resources existed.

A. More resources on the Company's system in actual operations would have resulted in a different system dispatch then what actually occurred, meaning a combination of changes in sales, purchases, and dispatchable generation to reoptimize the system around them.

Q. Please explain why the Company may have needed to acquire transmission.

A. In order to move generation to energy obligations, the Company may have needed to acquire transmission to connect the generation into the Company's system. This would have come at an additional cost to Washington's customers and was not included in the counterfactual analysis.

Q. Please explain why additional dispatchable resources may have been required to support these resources.

A. Although Schedule 3/3A Uncommitted Wind and Solar OATT rates were used to determine the cost to Washington customers of adding new renewable resources into the system, the Company may have been required to procure additional dispatchable resources to regulate for these resources which would have come at an additional cost to Washington customers.

Q. Why are the prices for the counterfactual resources possibly less than the price at which the Company would have been able to contract them?

A. These resources were priced identically to resources that actually connected with and produced energy for the system. Since these resources would have been in addition to the resources actually acquired, they would have most likely come at a higher cost which is not used in this counterfactual analysis.

Q. Please explain the trends identified in Figure 2.

A. While the counterfactual resources added in 2019 represent a relatively small portion of the overall resources used to supply Washington, they would have resulted in a significant increase to overall rates in 2019 and 2020 and would have had only a moderate impact as market prices spiked in 2021 through 2023. Counterfactual resources added in 2024 had lower costs than those added in 2019 reflecting downward trends for technology costs. The lowest cost NPC overall for Washington during the past ten years would have remained a system allocation of resources on the same allocation protocol as PacifiCorp's other five states.

Q. Can you draw any conclusions about Washington's exposure to market prices from Figure 2?

A. Yes, the large spike in market prices that began in 2021 was significantly greater on a dollar per megawatt-hour basis when compared to the WCA/WIJAM cost allocation methodology. This indicates the WCA/WIJAM methodology has already reduced Washington's exposure to market prices.

IV. 10-YEAR FORECAST ANALYSIS

Q. Please describe the forecasted portion of the counterfactual analysis.

A. At the time this analysis was prepared, PacifiCorp's Draft 2025 IRP preferred portfolio was the most up-to-date long-term forecast of system dispatch.[4] While the IRP uses inputs focused on long-term planning rather than ratemaking, it can be used to assess the impact of resource allocations on market position under the WIJAM net position balancing methodology. The analysis presented here evaluates how the counterfactual resources identified in Table 5 would impact Washington's forecasted market position and market costs under the WIJAM methodology.

Q. Please describe the model used to develop the IRP.

A. Starting with the 2021 IRP, PacifiCorp has used the PLEXOS model for IRP forecasting and resource procurement decisions.[5] PLEXOS includes two key modeling configurations: long-term (LT) portfolio expansion and short-term (ST) hourly dispatch.

Q. Please describe the PLEXOS LT model.

A. The LT model evaluates the entire study horizon, and identifies optimal combinations of resource additions, which together with existing owned and contracted resources, allow load to be served reliably and cost-effectively. It is important to add resources that are the best over time, not just in the current year, so the LT model evaluates the entire horizon of 20 years or more. To make this problem manageable, the LT model has limited granularity, and only assesses a few load and resource conditions for each

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[4] PacifiCorp's 2025 Draft Integrated Resource Plan, filed 12/31/2024 in Docket No. UE-230812. Available online at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=12&year=2023&docketNumber=230812.

[5] PLEXOS is a product of Energy Exemplar. See https://www.energyexemplar.com/plexos.

month. The primary output of the LT model is a portfolio composed of the cost-effective resource builds (or retirements) by technology, location, and year. This resulting portfolio is dependent on modeling inputs, including load, market prices, and the availability, cost, and operating parameters for different technologies.

Q. Please describe the PLEXOS ST model.

A. While the creation of a coherent, multi-decadal plan is a necessary step, the PLEXOS LT model produces a portfolio that performs best when load and resource conditions match the selected conditions used in the analysis. In reality, PacifiCorp experiences a much wider range of conditions in the many hours of each month, including wide variations in load, wind and solar output, and market prices. To get a better understanding of the real-world performance of a portfolio of resources determined by the LT model, the ST model evaluates every hour of each year so as to capture these varying conditions. To make this analysis more manageable, the ST model optimizes in one week steps (168 hours at a time), balancing load and resources in every hour while optimizing startups and shutdown of thermal resources and charging and discharging of energy storage, all subject to the operating limits of each resource. Costs are the primary output of the ST model, with a particular focus on variable costs like fuel and production tax credits, along with the costs or revenue associated with market transactions. The ST model also reports energy volumes and can be used to assess loss of load risk.

Q. Are the PLEXOS ST model results from the IRP generally comparable to results in AURORA used for regulatory net power costs?

A. Yes. There are many analogous, though not necessarily identical, modeling inputs between the IRP and regulatory net power costs, each of these inputs are discussed in more detail below:

- Load
- Transmission
- Signed contracts
- Electricity markets, including:
    - Market purchase limits
    - Market sales limits
    - Market price scenarios
    - Market price variation
    - Market Hedging

Q. How does the load forecast in the IRP compare to that used for regulatory net power costs?

A. The IRP uses a load forecast that excludes expected energy efficiency measure savings, so that it can select the optimal level of energy efficiency relative to other possible long-term resource options. Expected energy efficiency savings are already netted out of the load forecast used in regulatory net power costs.

Q. How does the representation of the transmission system in the IRP compare to that used for regulatory net power costs?

A. At the start the study horizon, the IRP uses a representation of PacifiCorp's existing transmission rights among the transmission areas or "bubbles" in which its loads and resources are located, much like regulatory net power costs. In the IRP, the PLEXOS LT model can also select from potential transmission upgrades that could be brought online in future years, enabling increased transfer capability between specific transmission areas and/or additional interconnection of resources within a given transmission area. The regulatory net power cost model also includes short-term transmission capability that PacifiCorp can use to flexibly respond to actual conditions. There is no certainty that such capacity will remain available over the IRP horizon. There is also the potential that long-term transfer capability increases identified through the IRP could be realized through future transmission reservations with other transmission providers, so there is some overlap in these concepts.

Q. How does the overall representation of markets in the IRP compare to that used for regulatory net power costs?

A. The IRP includes hourly optimization of purchases and sales at market points at specified prices, much like regulatory net power costs, but some of the inputs and limits for different aspects of market optimization are different to align with the intent of the long-term portfolio expansion.

Q. How do market purchase limits in the IRP compare to those used for regulatory net power costs?

A. Producing reliable portfolios is a key requirement of the IRP, and reliance upon market purchases could put reliability at risk, as the availability of willing sellers cannot be guaranteed. While past IRPs placed limits on the maximum allowable market purchases in the summer and winter peak seasons, the Western Resource Adequacy Program (WRAP) is expected to require capacity to be associated with specific physical assets, which is more restrictive than the types of market products available today. At the same time, PacifiCorp is working to join the California

Independent System Operator's Enhanced Day-Ahead Market (EDAM) in 2026, which should enhance the economic optimization of PacifiCorp's resource portfolio beyond the benefits already achieved through the Western Energy Imbalance Market (WEIM). Given the need for WRAP-compliant capacity, PacifiCorp's 2025 IRP does not allow market purchases during key hours on PacifiCorp's five highest load days in each month of the summer and winter peak seasons. To represent the benefits of economic market optimization in EDAM and WEIM, market purchases are only restricted based on transmission limits outside of the key hours on the top five days, and in all hours on other days. Because regulatory net power costs focus on balancing under normalized conditions over a near-term study horizon and cannot choose from among long-term supply options, short-term market purchases are the most likely outcome for any supply needs and are only restricted based on available transmission.

Q. How do market sales limits in the IRP compare to those used for regulatory net power costs?

A. PacifiCorp's 2025 IRP includes market sales limits that are comparable to those used by regulatory net power costs, with monthly heavy load hour and light load hour granularity. Because data for the 2025 IRP was locked down earlier in the process, the refinements identified in Company witness Ramon J. Mitchell's testimony were not incorporated. In a long-term planning context, market sales limits help ensure that resource selections are primarily providing value for serving load, rather than supporting wholesale sales, so the relatively small change resulting from the refined methodology would be expected to have minimal impact on long-term portfolio selection.

Q. How do market price scenarios in the IRP compare to that used for regulatory net power costs?

A. When PacifiCorp is preparing its IRP or identifying cost-effective long-term resource options for its Washington customers, it uses a price-policy scenario that includes the social cost of greenhouse gas emissions, in accordance with RCW 19.280.030. The IRP also includes analysis under several other price-policy scenarios that represent different natural gas market conditions and/or greenhouse gas emission costs or requirements. One of the other price-policy scenarios evaluated is PacifiCorp's quarterly official forward price curve (OFPC), with medium natural gas prices and no potential federal greenhouse gas emissions compliance costs. The Draft 2025 IRP preferred portfolio includes resource selections for Washington under a scenario that includes the social cost of greenhouse gas emissions, but because the present exercise relates to ratemaking impacts, the resulting portfolio is dispatched under the September 2024 OFPC, and do not include the social cost of greenhouse gas emissions. The December 2024 OFPC is used by regulatory net power costs for this proceeding. While the vintage of the two OFPCs is slightly different, they are fundamentally similar.

Q. How does market price variation in the IRP compare to that used for regulatory net power costs?

A. The 2025 IRP includes updates to several inputs intended to better capture the day-to-day relationship between supply and demand (via variation in load, wind and solar output, and thermal outage events) and market prices, which are a measure of the marginal cost of supply at a forecasted level of demand. For many years, PacifiCorp has used a chaotic normal load forecast that represents the full range of load conditions that would be expected to occur in a given month. The load forecast is based on the pattern of load conditions in a specific historical period, adapted to meet changing peaks and average energy expectations over the forecast period. The specific mapping of days also varies to align weekdays and weekends as they shift from year to year. The daily market price variation, wind and solar output, and thermal outage events in the 2025 IRP are all drawn from the same historical days used to develop the chaotic normal load forecast, ensuring that the range of outcomes and relationship between these variables reflect patterns experienced previously. The regulatory net power cost model includes a day-ahead/real-time pricing adjustment that helps account for the relationship between prices and PacifiCorp's supply and demand as evidenced in differences in average actual purchase prices and average actual sales prices.

Q. How does market hedging in the IRP compare to that used for regulatory net power costs?

A. Modeling for the 2025 IRP does not differentiate between different types of market products and does not have a representation of the time-to-delivery aspects of PacifiCorp's hedging policy. In past IRP's, front office transactions (FOTs) were identified that represented expected short term firm purchases to needed to meet capacity and reliability requirements. This is reasonably aligned with PacifiCorp's existing hedging policy. However, with the expected start of WRAP compliance by November 2027, market purchases intended to cover resource adequacy requirements will generally need to be for specified resources, and the unspecified-source market purchases that make up most of PacifiCorp's short term firm purchases will not qualify. In the absence of more certainty around the availability of short-term capacity products for WRAP compliance, the 2025 IRP targets WRAP compliance using its existing portfolio and long-term resource options, and has not included an option for short-term products as part of portfolio development. In the near term view represented in regulatory net power cost results before WRAP compliance begins, PacifiCorp's hedging programs will continue much as they have in the past unless more restrictive market purchase requirements are necessary.

Q. How are signed contracts represented in the IRP relative to modeling for regulatory net power costs?

A. The IRP includes the output of all signed contracts in PacifiCorp's portfolio, including those situs-assigned to other jurisdictions. This is comparable to the treatment in actual net power costs, where the output from those resources is present, even though it is not allocated to Washington customers. The IRP is focused on balancing load and resources, and the cost of future resource options, so for existing resources and signed contracts it only includes those attributes related to generation output and dispatch flexibility. For example, power purchase agreements for solar resources (those that are not qualifying facilities) generally include a compensable curtailment clause, allowing PacifiCorp to direct the facility to curtail its generation when market prices fall below zero. When curtailment due to low market prices occurs, PacifiCorp still pays the seller the contract price for what its output would have been in the absence of the curtailment. As a result, the marginal cost of the contracted solar resource in this example would be zero, as the contract price would be paid for either generation or curtailed output. With this in mind, the IRP models marginal dispatch costs for existing contracts rather than contract prices, and does not report comprehensive cost detail for existing contracts like that produced for regulatory net power costs, as costs that can't be influenced by portfolio changes do not impact portfolio outcomes. Regulatory net power costs, as a ratemaking exercise, has to include accounting-level detail for all costs classified as part of net power costs, in addition to accurately accounting for cost impacts related to dispatch.

Q. Does the IRP include other costs that are not part of regulatory net power costs?

A. Yes. IRP modeling produces optimized portfolios of resource and transmission based on all of the cost associated with potential resource additions, and all of the ongoing costs (i.e. not including embedded rate base) for existing resource options that are considered for possible retirement. These costs upfront build costs that would be incorporated in rate base, retirement or decommissioning costs, as well as ongoing fixed and variable operations and maintenance expense (some of which would be rate-based), none of which is part of regulatory net power costs. In addition, IRP modeling accounts for the revenue requirement value of production tax credits. While this is not part of the customary definition of net power cost, it is often modified based on the results of the net power cost forecast, since the value is tied to the expected generation from eligible assets that is part of the net power cost results.

Q. With all of the differences between IRP modeling and regulatory net power costs, can IRP modeling results provide meaningful information about the impacts of generation resources relative to market positions?

A. Yes. While not a comprehensive net power cost forecast, IRP modeling results can report details on the key inputs to the WIJAM methodology:

- Monthly net position:
    - Washington load
    - Washington resource allocation
- Monthly balancing transactions:
    - System wholesale sales volume and average sales price
    - System market purchase volume and average purchase price

The requested comparison of incremental generation resources to an open market position is ultimately a comparison of portfolios, not unlike the IRP itself, and the cost differential between these portfolios can be reported for the incremental generation resources and market balancing costs in question. The rest of the components of net power costs under the WIJAM methodology are not impacted by changes in the allocation of resources to Washington, so their costs cancel out for this analysis and do not need to be considered.

Q. Please describe the portfolio and allocations used to represent the current forecast of the WIJAM net balancing position.

A. This analysis reflects PacifiCorp's existing portfolio of resources, and their allocation under the current WIJAM methodology. The forecast for these resources is derived from PacifiCorp's 2025 IRP Draft preferred portfolio results. For the purpose of this existing portfolio analysis, no future resource additions are included, other than energy efficiency selections which are presented as subtractions from the forecasted pre-energy efficiency load used in IRP modeling. These allocations include:

- Natural gas resources using Control Area West factors (approximate 19% energy factor in 2026): Chehalis, Hermiston, Jim Bridger 1&2 (natural gas converted). These resources have been modeled as distinct "Oregon" and "non-Oregon" versions for the 2025 IRP so that dispatch impacts related to Oregon emissions compliance requirements can be isolated. As a result, Washington's 19 percent share is equivalent to 26 percent of the non-Oregon portion of these resources.

- System clean resources using system factors (approximate 7 percent generation factor in 2026).
- Coal-fired resources: no allocation to Washington in 2026 and beyond.
- Qualifying facilities (QFs): situs to each jurisdiction (Washington receives 100 percent of its own QFs and zero percent of QFs in other states).

Q. Please describe the portfolio and allocations used to represent the counterfactual forecast of the WIJAM net balancing position.

A. This analysis reflects PacifiCorp's the current portfolio, as described above, except the allocation of the counterfactual resource additions identified as part of the historical analysis is increased.

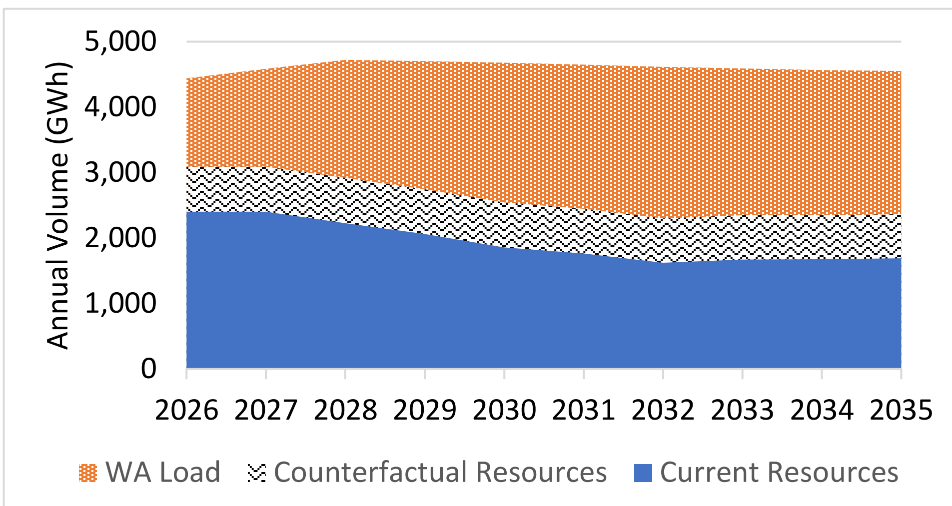
Q. Are the counterfactual resource additions represented within the modeling results?

A. No. The WIJAM methodology is based on the total system load and resource dispatch results. For this counterfactual analysis, only the allocation of resources to Washington is adjusted, to align with the 240 megawatts of resource additions by 2024, as identified in Table 5 in the 10 Year Historical Analysis section of this testimony.

Q. What is Washington's forecasted annual load and resource balance with its current resources and with the addition of the counterfactual resources?

A. Figure 3 shows Washington's load as well as the current level of resources and the incremental volume associated with the counterfactual resources under the existing WIJAM methodology. As shown, Washington's load significantly exceeds its resource allocations in both instances. The capacity factor of Washington's natural gas resources is projected to fall through time and provide over 500 GWh less energy in 2035, relative to 2026. Expiring long-term contracts and Washington's declining system allocation factor also play a role in the declining resource position. The counterfactual resource volume adds approximately 687 GWh in 2026, falling slightly to 672 GWh in 2035, due to solar degradation. Both current resources and counterfactual resources leave a significant annual energy balancing position to be addressed through the WIJAM methodology.

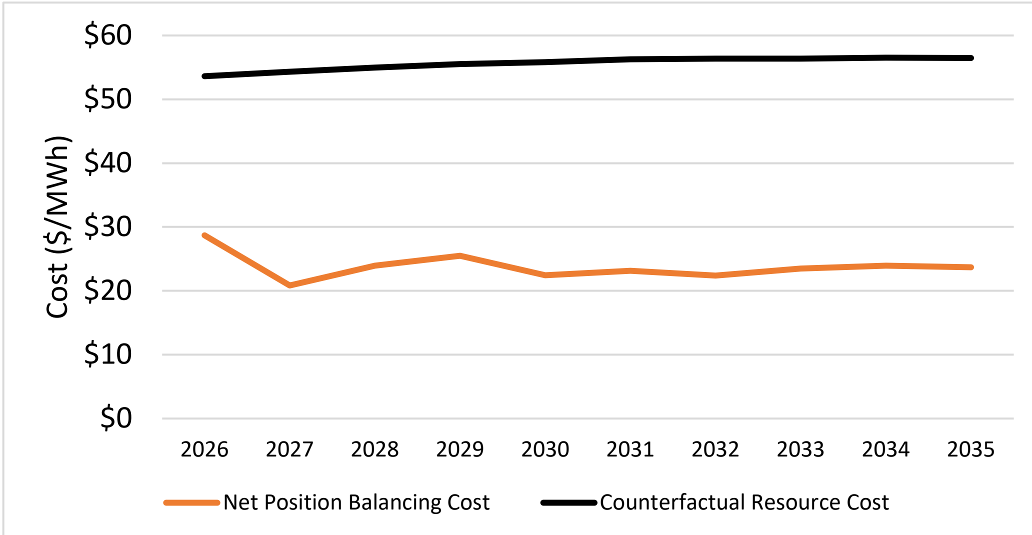
Figure 3: Forecasted Load and Resource Balance



Q. How does the cost of the counterfactual resources compare to the forecasted monthly market balancing costs they displace?

A. Figure 4 shows the average annual cost of the counterfactual resources, as well as the average annual cost of the market balancing transactions they would displace under the WIJAM. The cost of the counterfactual resources is well above that of the forecasted market balancing transactions Washington would be allocated to fill its short position under the WIJAM.

Figure 4: Counterfactual Resource Cost versus Market Balancing



Q. How would the counterfactual resources have impacted Washington-allocated net power costs under WIJAM?

A. Based on the IRP modeling results, the cost differential between the counterfactual resources and the forecasted balancing transactions that they would displace would increase Washington-allocated net power costs by an average of $21.7 million per year from 2026-2035. Relative to the Washington-allocated net power costs currently in rates for 2025 of approximately $190 million,[6] the $17.1 million counterfactual resource cost impact in 2026 represents an increase of roughly 9 percent.

V. CONCLUSION

Q. Please summarize your testimony.

A. Any counterfactual analysis is heavily dependent on assumptions and significant uncertainty about future conditions. It necessitates the use of information that would not have been available at the time that these decisions were made. Despite these

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[6] *WUTC v. PacifiCorp.,* Docket Nos. UE-230172 and UE-210852 (Consolidated), Compliance Filing (Mar. 26, 2024).

concerns in preparing this counterfactual, the analysis shows that Washington customers would have faced higher costs prior to 2021 and only slightly lower costs from 2021-2024. Additionally, this counterfactual analysis indicates that the counterfactual resources that would have been acquired would increase Washington-allocated net power costs by an average of $21.7 million per year from 2026-2035.

Q. Does this conclude your direct testimony?

A. Yes.