WUTC DOCKET: UE-230172 & UE-210852
EXHIBIT: JP-1T
ADMIT ☑ W/D ☐ REJECT ☐

Exh. JP-1T
Docket UE-230172
Witness: Jack Painter

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-230172

PACIFICORP

DIRECT TESTIMONY OF JACK PAINTER

March 2023 (REFILED April 19, 2023)

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company).

A. My name is Jack Painter and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Specialist.

Q. Briefly describe your education and professional experience.

A. I received a Bachelor of Arts degree in Business Administration with a Finance major from Washington State University in 2007. I have been employed by PacifiCorp since 2008 and have held positions in the regulation and jurisdictional loads departments. I joined the regulatory net power costs group in 2019 and assumed my current role as a Net Power Cost Specialist in 2020.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the public utility commissions in Washington, Oregon, California, Utah, Wyoming, and Idaho.

II. PURPOSE OF TESTIMONY

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

A. My testimony focuses on providing an overview of the current power cost adjustment mechanism (PCAM) structure and presents the Company's proposal to eliminate the deadband and asymmetrical sharing bands from the PCAM due to the difficulty in accurately forecasting net power costs (NPC) and the Company's pending participation in an independent system operator type organized market.

III. CURRENT PCAM STRUCTURE

Q. Please explain the current PCAM structure and its components.

A. The PCAM accounts for differences between Forecast NPC and Actual NPC incurred by the Company.[1] Forecast NPC establishes both the level of power costs embedded in electric rates and the level of power costs from which the deadband and asymmetrical sharing bands operate in the PCAM. The variances between Actual NPC and Forecast NPC first flows through the deadband and asymmetrical sharing bands, and then get booked into a deferral account and reflected in the PCAM cumulative balance. If the cumulative balance exceeds $17 million, either a credit or surcharge may be assessed during the PCAM annual review, which is filed with the Commission on June 15 of each year.

Q. How does the Company forecast NPC?

A. Forecast NPC is established in a general rate case or a power cost only rate case filing. The Company forecasts its system-wide NPC using the Aurora model, which simulates the operations of the Company's system for its entire fleet across all its state jurisdictions, along with contracted generation, market purchases, and sales. NPC is calculated as the sum of fuel costs, purchase power costs, wheeling expenses, net of wholesale sales revenue. The model results are adjusted to reflect incremental Energy Imbalance Market (EIM) benefits. Total Company-wide NPC are allocated to Washington using the Washington Inter-Jurisdictional Allocation Methodology. Any deviation from Forecast NPC and Actual NPC multiplied by actual retail sales

[1] The PCAM was adopted in a settlement during the 2014 general rate case. *See WUTC v. PacifiCorp,* Docket Nos. UE-140762 et al., Order 09 (May 26, 2015).

volumes becomes the variance that is subject to partial refund or recovery through the PCAM.

Q. Please explain the PCAM deadband in more detail.

A. The variance between Actual NPC and Forecast NPC will first flow through a $4 million deadband. Accordingly, any variance between actual and forecast costs below $4 million (in either the surcharge or credit direction) is not reflected in the cumulative deferral balance. This component essentially deducts $4 million from any potential credit to customers or surcharge by the Company.

Q. Please explain the PCAM asymmetrical sharing bands in more detail.

A. After application of the deadband, the remaining variance between Forecast NPC and Actual NPC that exceeds $4 million is subject to a set of asymmetrical sharing bands, which further reduces any potential credit to customers or surcharge by the Company. If the variance is a credit to customers, the first sharing band is a 75/25 percent split between customers and the Company for amounts between $4 million (deadband) and $10 million. After $10 million, the sharing band changes to a 90/10 percent split between customers and the Company. If the variance is a surcharge to customers, the first sharing band is a 50/50 percent split between the Company and customers for amounts between $4 million (deadband) and $10 million. After $10 million, the sharing band changes to a 90/10 percent split between the Company and customers. After the variances flow through the deadband and asymmetrical sharing bands, the amounts are booked in the PCAM deferral account and reflected in the PCAM cumulative balance.

Q. Please explain the credit or surcharge threshold.

A. The PCAM has a credit and surcharge threshold of $17 million. During the annual PCAM review, filed on June 15, the Commission determines if the cumulative balance exceeds the $17 million threshold for a surcharge or a credit, given the operation of the PCAM mechanism just discussed. A cumulative $17 million balance, in either the credit or surcharge direction, can be met in a single annual PCAM filing or multiple annual filings. Rate changes are not implemented until a cumulative credit or surcharge balance of $17 million has been reached in the deferred balancing account.

Q. What is your understanding of the purpose and intent of the components that are in place for the PCAM?

A. It is my understanding that the components of the PCAM have two main objectives:

- To equitably share risk between the customers and the Company for power cost variability;[2] and
- To incentivize the utility to effectively manage or reduce power costs.[3]

[2] *See e.g., In the Matter of the Petition of Avista Corp. for Continuation of the Company's Energy Recovery Mechanism, with Certain Modifications*, Docket No. UE-060181, Order 03, ¶ 23, Finding of Fact 3 (June 16, 2006); *See also WUTC v. PSE*, Docket Nos. UE-011570 & UG-011571, Twelfth Supplemental Order, ¶ 22 (June 20, 2002); *WUTC v. Puget Sound Energy,* Docket Nos. UE-220066 et al., Exh. HEN-1T at 9 (July 28, 2022) ("The goals of the PCA mechanism and its respective sharing bands are to: (1) equitably share risk between the shareholder and the ratepayer of power cost variability in the rate years; and (2) incentivize the utility to effectively manage or even reduce power costs.")
[3] *Id.*

Q. Do the current PCAM deadband and asymmetrical sharing bands accomplish the goal of equitably sharing risk between the customer and the Company for power cost variability?

A. No. As provided in more detail in my testimony, and illustrated in Table 1 below, the modeling of Forecast NPC has become less accurate, and will likely continue a trend of substantial deterioration due to regional forward power market price forecasts in the western interconnection becoming less accurate and renewable resources being added to the Company's system, which are needed to comply with Washington laws, including the Clean Energy Transformation Act (CETA). This is concerning because an inaccurate forecast of NPC can result in an unbalanced outcome for customers, given the existence of the deadband and asymmetrical sharing bands.[4] Because the modeling of the underlying Forecast NPC will likely continue to be less accurate, removing the deadband and asymmetrical sharing bands from the PCAM will ensure that the Company only recovers prudently incurred power costs and customers only pay prudently incurred power costs, no more and no less.

Q. Do the current PCAM deadband and asymmetrical sharing bands accomplish the goal of incentivizing the utility to effectively manage or reduce power costs?

A. No. As provided in more detail in my testimony, the Company has announced its intention to join the Extended Day Ahead Market (EDAM), which will create efficiencies that reduce NPC.[5] Once the EDAM is operational in 2025, the Company

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[4] *WUTC v. Avista Corp.* Docket No. UE-171221, Order 07 (April 26, 2018) ("What is clear in the record is that Avista's power cost forecasts have been *consistently unbalanced in the Company's favor over recent years*. Avista has not supplied a backcast or other analysis to isolate the effect of lower natural gas prices and power prices on the *directionally biased results* observed over the last six years. The modeling concerns Mr. Gomez and Ms. Wilson raise are a first effort to remedy the repeated, *unbalanced outcomes* and may offer some explanation as to the cause of the observed inaccuracies.") (emphasis added).

[5] https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html.

will no longer control the economic dispatch of its resources, which means a majority of NPC will no longer be under the Company's direct control. Given that the Company will no longer have economic dispatch of its resources, the deadband and asymmetrical sharing bands are no longer effective or necessary to incentivize the Company to effectively manage or reduce power costs.

IV. FORECAST NPC INACCURACY

Q. In a power cost adjustment mechanism that contains a deadband and asymmetrical sharing bands, can an inaccurate NPC forecast result in an unbalanced outcome for customers?

A. Yes, if Forecast NPC is over-forecasted it can result in unbalanced outcomes for customers. For example, in dockets UE-170485 and UG-170486, Commission Staff (Staff) argued that Avista Corporation's (Avista) proposed increase to its Forecast NPC should be denied because Avista had a "recent history of consistently over-forecasting its power costs."[6] Staff further explained "because of the way dead bands and sharing bands are structured . . . if the authorized baseline [NPC] is consistently set too high, the Company will receive a windfall at customers' expense"[7] and that Avista was "generating excess revenue that the Company [could] keep through the dead and sharing bands and padding the ERM deferral account . . .".[8] Accordingly, Staff provided that "Avista [had] over-collected its power costs by $64.6 million and,

[6] *WUTC v. Avista Corp.* Docket No. UE-171221, Order 07 ¶ 122 (April 26, 2018).
[7] *Id.; see also id.* ¶ 123 ("Mr. Gomez briefly recounts the history and purpose of Avista's ERM, which uses dead bands and sharing bands to: (1) equitably allocate between Avista and its Washington customers the risk of ordinary power cost variability, and (2) incentivize Avista to effectively manage or even reduce its power costs.") (citing Order 03 in Docket No. UE-060181).
[8] *Id.* ¶ 125.

because of the dead and sharing bands, has kept $24.1 million—an average of $4.1 million a year."[9]

Although the Commission granted Avista's increase to Forecast NPC, the Commission made a finding that "[w]hat is clear in the record is that Avista's power cost forecasts have been consistently *unbalanced in the Company's favor* over recent years."[10] The Company disagrees with Staff that the remedy for the unbalanced sharing of power costs in a company's favor is to prohibit an increase to Forecast NPC. Rather, the appropriate remedy should be removing the deadband and asymmetrical sharing bands, which would provide for a full return to customers for the variance and not allow for such an unbalanced outcome.

Q. What is the historical impact of the deadband and asymmetrical sharing bands in the PCAM?

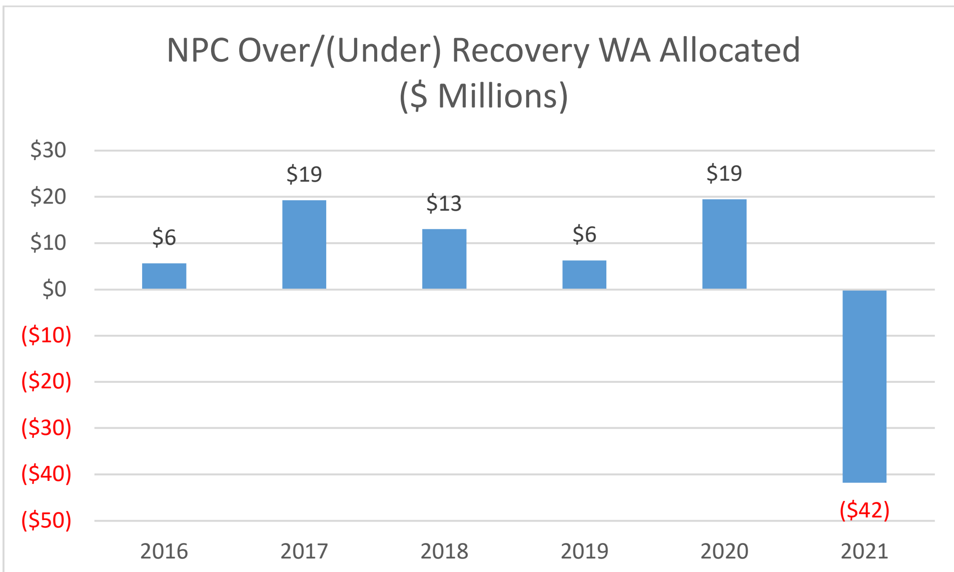
A. Please refer to Table 1 and Figure 1 below. Since 2016, the first full calendar year in the PCAM, and the most recent PCAM filing for 2021, the total loss to Washington customers due to the deadband and asymmetrical sharing bands is $27.6 million, while the loss to the Company is $10.2 million. Washington customers would have significantly benefited with a PCAM that did not contain a deadband or sharing bands.

[9] *Id.*
[10] *Id.* ¶ 156 (emphasis added).

Table 1

Historical PCAM Variances	2016	2017	2018	2019	2020	2021
Total Company Actual NPC $	1,465,887,270	1,529,959,607	1,592,124,916	1,660,495,378	1,511,314,189	1,714,607,879
WA Allocated Actual NPC $	120,853,501	114,820,703	112,392,441	125,364,469	109,613,104	164,765,848
Actual WA Retail Sales MWh	3,981,654	4,221,298	3,949,116	4,144,590	4,065,151	4,198,961
Actual PCAM Costs $/MWh	$30.35	$27.20	$28.46	$30.25	$26.96	$39.24
WA Allocated Base NPC in Rates $	127,364,595	127,364,595	127,364,595	127,364,595	127,364,595	119,524,079
Base WA Retail Sales MWh	4,010,161	4,010,161	4,010,161	4,010,161	4,010,161	4,081,607
Base PCAM Costs $/MWh	$31.76	$31.76	$31.76	$31.76	$31.76	$29.28
Variance $/MWh	$1.41	$4.56	$3.30	$1.51	$4.80	($9.96)
Refund/(Recovery)	$5,605,682	$19,249,685	$13,033,308	$6,269,634	$19,497,996	($41,805,222)
Deadband/Sharing Bands Loss	($4,401,421)	($6,424,969)	($5,803,331)	($4,567,409)	($6,449,800)	$10,180,522
Net Refund/Recovery	$1,204,262	$12,824,717	$7,229,977	$1,702,226	$13,048,196	($31,624,700)

Figure 1



Q. **Do you believe that Forecast NPC will continue to be inaccurate as compared to Actual NPC?**

A. Yes. Although several factors can contribute to the modeling of the underlying Forecast NPC being inaccurate as compared to Actual NPC, I believe that: (1) regional forward power market price forecasts in the western interconnection becoming less accurate; and (2) renewable resources being added to the Company's system will primarily contribute to the continued inaccuracy of Forecast NPC. Accordingly, I recommend that the deadband and asymmetrical sharing bands be removed from the PCAM to allow the Company to fully refund to customers or only recover its prudently incurred power costs, and not allow for any possible unbalanced outcomes in power costs.

A. <u>Regional Market Prices</u>

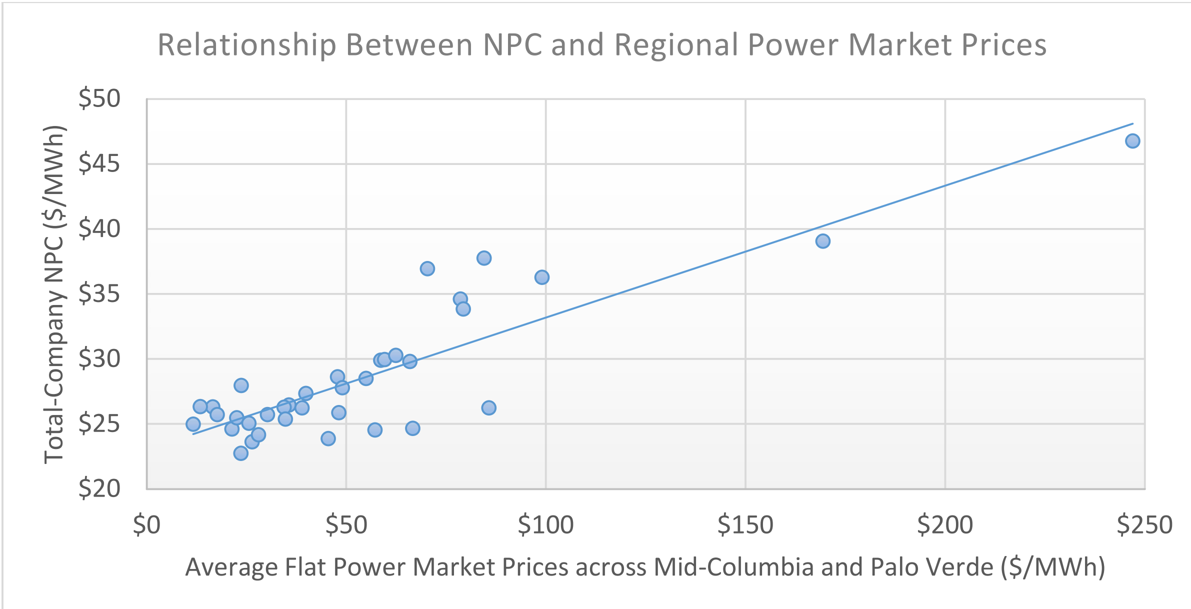
Q. Can you please summarize this sub-section?

A. Yes. The modeling of Forecast NPC has become less accurate, in part, because regional forward power market price forecasts in the western interconnection have become less accurate, which is particularly problematic given that NPC forecasts rely on regional market price forecasts that are often developed more than one year before rates are effective. In prior decades, these forecasts were *relatively* stable, but, in recent years these forecasts have become less accurate, as indicated in Figure 1 above. Given that the modeling of the underlying Forecast NPC has become less accurate, due to regional forward prices, removing the deadband and asymmetrical sharing bands will eliminate the possibility of inequitable sharing of power cost variances and allow the Company to either fully refund to customers or only recover its prudently incurred NPC.

Q. What is the relationship between NPC and regional power market prices?

A. NPC are driven by and are proportionate to regional power market prices as illustrated below in Figure 2.

Figure 2



Q. How are regional power market price forecasts developed?

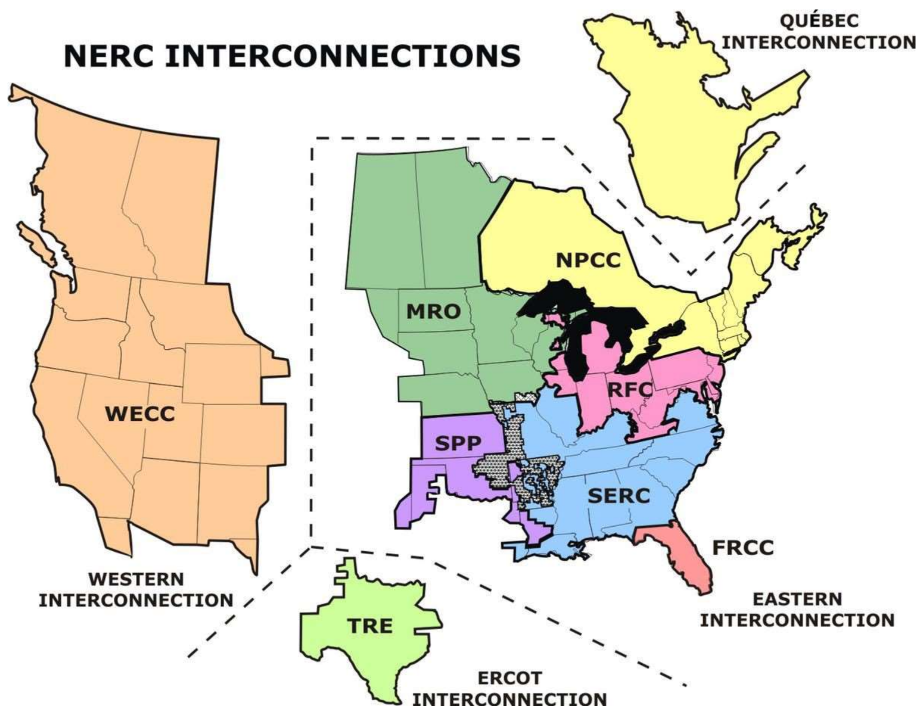
A. Regional power market prices for forecasts one to three years out (the prices used in the official forward price curve) are actual market prices in the actual forward power markets within the western interconnection. These prices are not created by the Company but are determined by the aggregate trading activity of all regional market participants.

Q. What is the western interconnection?

A. Please refer to Figure 3 below. The western interconnection is the geographic area containing the synchronously operated electric grid in the western part of North America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming, and Mexico plus all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington, and the Canadian provinces of British Columbia and Alberta.[11]

Regional power market prices are based on the supply and demand across the entirety of the western interconnection, subject to transmission limitations. Other interconnections play a limited to negligible role in regional power market prices given the limited transmission connectivity between interconnections.

Figure 3



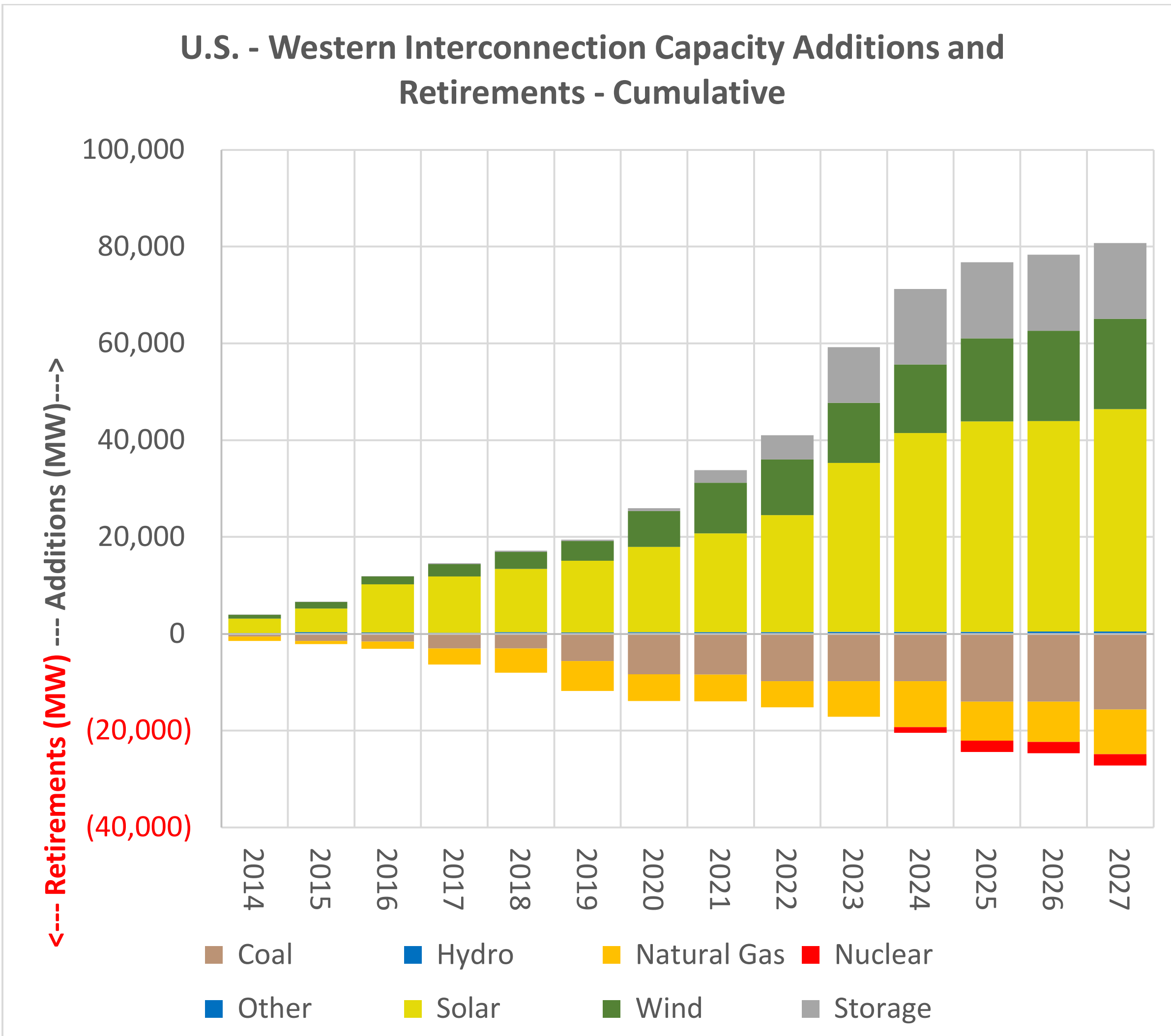
Q. Why have regional power market price forecasts in the western interconnection become less accurate in recent years?

A. The resource mix across the western interconnection has evolved from one dominated by controllable thermal generation to one dominated by intermittent weather-

[11] *The Western US Power System*, TRANSMISSION AGENCY OF NORTHERN CALIFORNIA (accessed Feb. 23, 2023), https://www.tanc.us/understanding-transmission/the-western-us-power-system/.

dependent generation. Specifically, coal and gas generation facilities are being retired and replaced with wind and solar generation facilities. Figure 4 below illustrates this year-over-year change in the western interconnection's resource mix.

Figure 4



Q. Are these resource mix changes in the western interconnection a consequence of, or driven by, the Company's decisions?

A. No. The Company's portfolio of wind and solar resources is only approximately four percent of the total wind and solar capacity across the western interconnection. Had the Company not installed a single megawatt (MW) of wind or solar generation, the

NPC forecast would still be driven by market prices and, therefore, still suffer from difficulties in forecast accuracy resulting from the region-wide adoption of these weather dependent resources.

Q. Why has the change in resource mix within the western interconnection decreased NPC forecast accuracy?

A. Current forecasting techniques are incapable of accurately predicting the weather one-to-two years out into the future. For example, the wind speeds across the western interconnection during the month of February in 2024 are impossible to predict with any reasonable degree of accuracy on the day that this testimony was filed in March of 2023.[12] Using the Pacific Northwest as an example, wind generation changes are correlated with regional power market price changes, and consequently, any material variance in wind generation from forecast to actual corresponds to a material variance in regional power market prices, from forecast to actual.

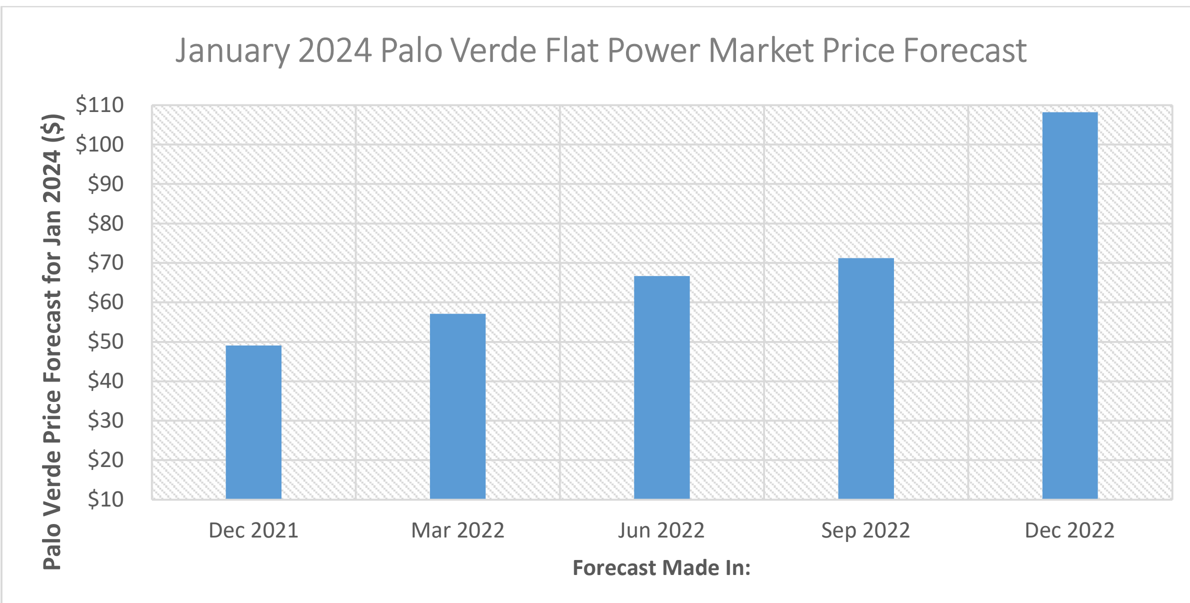
As the resource mix in the western interconnection becomes more dominated by generation that is dependent on wind speed and solar irradiance (sunshine), the regional power market price expectations for one-to-two years out become less accurate. As previously illustrated in Figure 2 above, any material change in the regional market prices corresponds to a proportionate and material change in NPC and the associated NPC forecast accuracy (variance).

[12] Across an annual period, average wind speed forecasts are borderline reasonably accurate. At more detailed levels of granularity, example monthly or hourly, these forecasts do not exhibit reasonable levels of accuracy.

Q. How has the uncertainty (unreliability) of regional power market price forecasts manifested?

A. Using January 2024 as an example, regional power market price forecasts demonstrate unreliability through an examination of the quarter-over-quarter forecasts of average power market prices at Palo Verde for the month of January 2024. The illustration in Figure 5 below starts with the prices taken from real broker quotes on December 31, 2021, and ends with the quotes taken on December 30, 2022.

Figure 5



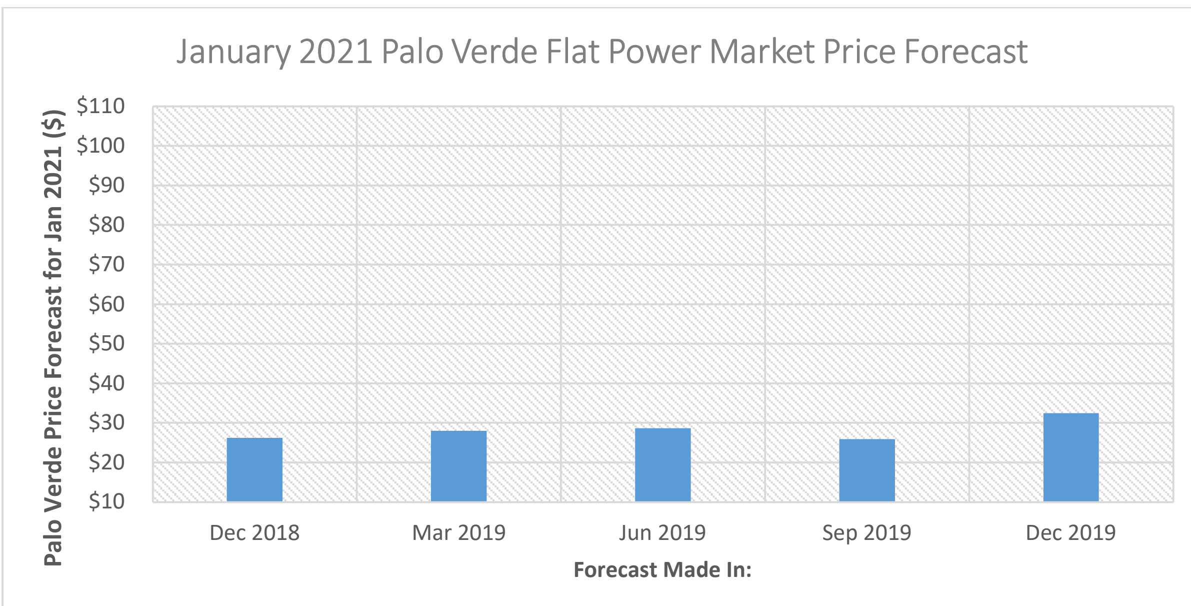
Q. What does Figure 4 show?

A. Figure 4 above makes clear the fact that the price expectations for January 2024 increased every quarter by a substantial amount. Were this NPC forecast created before December 31, 2022, the NPC would look markedly different, and substantially lower than the current forecast. This scenario of under-forecast exacerbates as one goes backward in time. It is near impossible to determine with any reasonable degree of accuracy what the January 2024 price will actually be in January of 2024.

Q. How does this price forecast of January 2024 compare to January 2021?

A. Figure 6 below illustrates similar quarter-over-quarter forecasts for the month of January 2021. It starts with the prices taken from real broker quotes on December 31, 2018, and ends with the quotes taken on December 30, 2019. Figure 6 below is scaled identically to Figure 4 above and illustrates that during calendar year 2019, the price expectations for January 2021 were relatively stable. Comparing Figure 4 against Figure 6 demonstrates the factual increase in the unreliability of regional market price forecasts between the last general rate case[13] and this filing.

Figure 6



Q. How have extreme weather events impacted regional power market prices?

A. Calendar years 2020, 2021, and 2022 have seen an increase in abnormal/extreme weather events that have resulted in higher-than-expected load during stressed system conditions, and this trend has set expectations amongst market participants for similar

[13] *See* Docket No. UE-191024.

conditions in 2024. For example, the 2021 PCAM imbalance, illustrated in Table 1, reflects power cost variances resulting from two extraordinary weather events: a mid-February polar vortex and June through July heatwave.[14] Although market participants hold expectations that unpredictable weather events will continue, these events are by definition uncertain and may or may not materialize on time, or at all. Consequently, the actual 2024 power market prices are equally uncertain. These extreme events and corresponding rise in energy prices are not forecastable and are completely outside the Company's control.

Q. Can you please give another example of how this short-term variability impacts NPC?

A. If the western PacifiCorp service territory experiences an unexpected heat wave during a summer month, demand for electricity will increase and spike upwards, not only for the Company, but also other utilities. To meet this unplanned load increase, the Company would have to rely on either its more expensive generating resources that were not operating for forecast load levels or purchase from the market. To the extent that neighboring utility systems are experiencing similar conditions, market spot prices will be significantly higher than normal. The supply shortfall may be further worsened if other renewable resources are generating less than expected as sometimes happen with wind turbines in heat waves or hydro resources in drought conditions. Consequently, the Company would have to secure even more power than just the load increase at a much higher price which in turn compounds and drives up NPC.

[14] *See* Docket No. UE-210447.

In another example, if the Company's renewable resources are generating more than forecasted due to favorable weather conditions, then the Company would be able to either increase its sales to the wholesale market or back down its more expensive generating resources. Either of these scenarios will create unforecastable net power costs variances, which ultimately should be passed back to customers or recovered by the Company without a deadband or asymmetrical sharing bands.

Q. How has the conflict in Ukraine impacted regional natural gas fuel prices?

A. The conflict in Ukraine has decreased European availability of natural gas, previously sourced from Russian imports. With decreased European supply, the associated European demand has turned to U.S. domestic supply to fill the gap and the increased competition over domestic supply has driven regional natural gas fuel prices upwards with increases in domestic production unable to keep pace with the increased demand. This increase in natural gas fuel prices correspondingly increases regional natural gas market prices and regional power market prices, in that order. It is difficult to predict (or forecast) how long, and in what direction, these factors will continue to impact regional prices.

Q. Are rapidly changing environmental compliance requirements creating more uncertainty in forecasting NPC?

A. Yes. For example, as provided in the testimony of Company witness Ramon J. Mitchell there is uncertainty as to the Environmental Protection Agency's Ozone Transport Rule depending on whether Wyoming is subject to those rules. That uncertainty has an impact on Forecast NPC that is outside the Company's control. It would be inequitable for either the customer or the Company to bear the risk of any

NPC variances resulting from such uncertainty related to environmental compliance requirements.

B. Renewable Resources

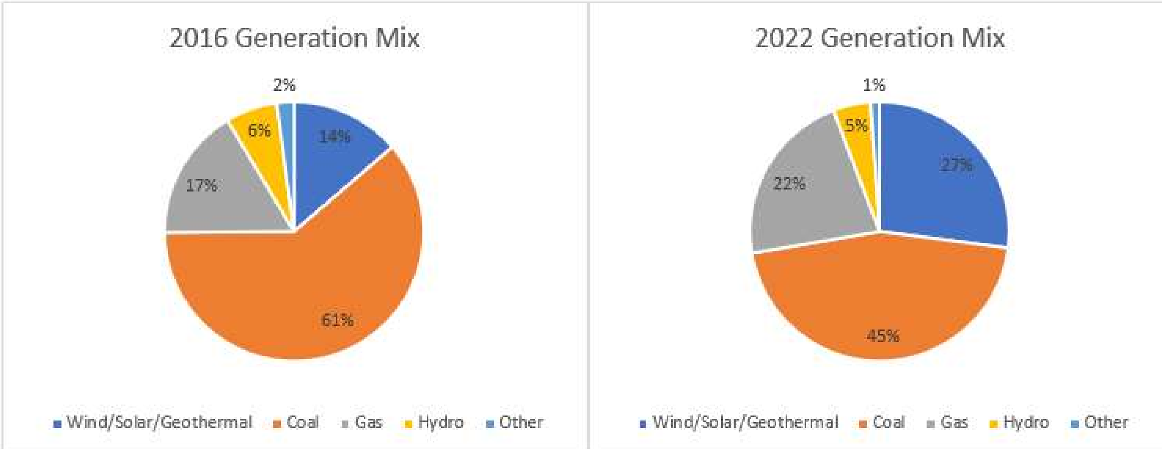
Q. Can you please summarize this sub-section?

A. As weather dependent generation continues to increase throughout the Company's system and region, the one to two years out regional generation forecasts and the associated regional market price forecasts will become less accurate. This, in turn, will substantially increase the difficulty of creating accurate Forecast NPC forecasts. Given that the modeling of the underlying Forecast NPC has become less accurate due to the increase in weather dependent generation, removing the deadband and asymmetrical sharing bands will eliminate the possibility of inequitable sharing of power cost variances and allow the Company to fully refund to customers or only recover its prudently incurred NPC.

Q. How have renewable resources changed since the PCAM was established?

A. From 2016 through 2022, megawatt hours produced by wind, solar, and geothermal resources have almost doubled from 14 percent of the Company's system generation to 27 percent of the system generation. At the same time, coal and gas generating base load resources have decreased by 11 percent of system generation over the period. Please refer to Figure 7 below, which illustrates the generation output by resource type in 2016 and 2022.

Figure 7



Q. Have Washington laws and regulations influenced the Company's decision to procure more renewable generation?

A. Yes. The Company has procured additional renewable generation to comply with Washington law, including CETA.

Q. Please summarize why the shift to more renewable resources is likely to intensify NPC variances.

A. There are two different impacts on NPC from the increase of renewable resources on the Company's system. The first lowers the average cost of fuel in NPC by virtue of the zero-cost energy of the renewable resource output replacing fossil fuel generating resources output. This will lower the base rates component forecast by the model. However, the second impact is more complex, and occurs because it is more difficult to forecast renewable generation on a short-term basis. When, inevitably, the renewable generation deviates in actual operations from the forecast, the Company has to re-dispatch with more expensive resources or market purchases. There will be additional correlation across the entire power system resources in output, as PacifiCorp and much of the western interconnection increase their renewable resources because all are responding to the same shared conditions from the sun or wind. While it is true that there is geographic diversity across large regions for when and where the renewable resources will be generating, it is also true that huge areas can and will experience similar weather conditions. Unlike fossil fuel generating facilities, whose outage characteristics are relatively independent, renewable resources tend to face this risk jointly, thus causing much bigger and more sudden variances in NPC.

Q. Can you further explain how the increase in renewable resources impact NPC variability?

A. Yes. As more renewable resources are introduced to the Company's system, their availability on an hourly or even seasonal basis due to weather conditions are nearly impossible to forecast. When all other resources are optimized and the Company is unable to meet customer demand, the only option is to purchase energy through the market at prices that the Company has little to no control over. Over the long term, the Company may be able to forecast how much output a given resource is able to produce, but in the short term, market purchase volumes, and the prices at which they occur are quite sensitive. These prices could be lower or higher than initially forecasted, but because they are outside of the scope of control for a utility, the customer should receive both the benefits of an over forecast, and the costs of an under forecast. Even with annual average performance of renewable resources well known, and possibly even hedged, there is a great deal of volatility and complexity to this component of NPC over short time frames.

Q. How does expected wind output enter into the forecasts that the Company uses to set base NPC rates?

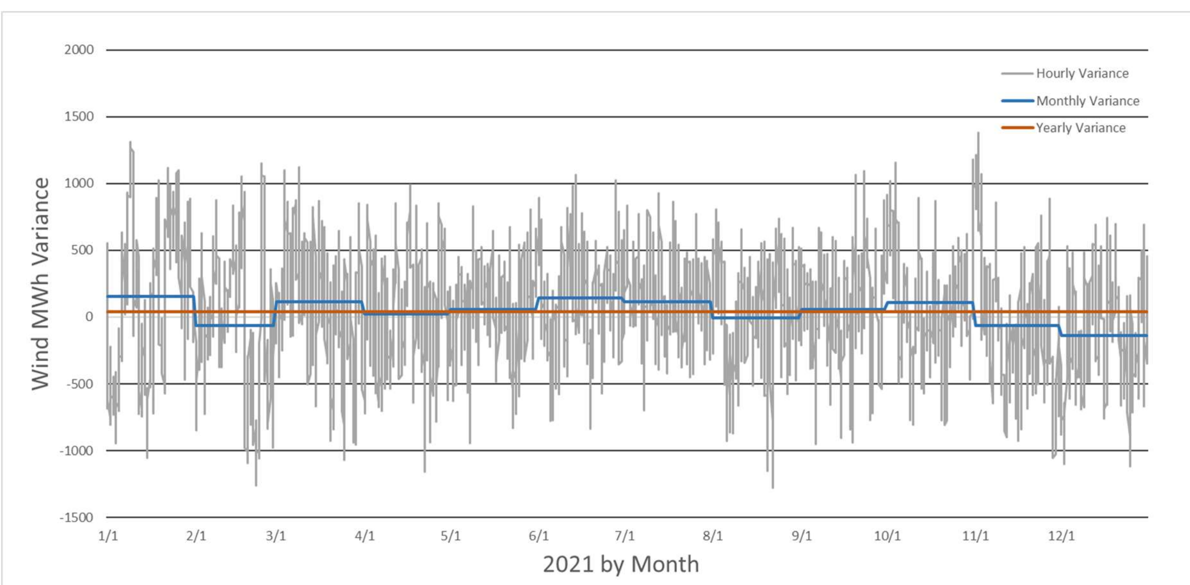
A. It is very difficult, if not impossible, to forecast when and how much wind will occur within a forecast test period. As a result, PacifiCorp uses a flat average of historical annual wind conditions at each site for total output, shaped by the time pattern in the most recent past year of actual output to project generation from its wind plants or it uses the developer's projections if the plant has less than four years of history. This is a reasonable way of projecting those patterns, capturing both the steadiness of the long-term wind patterns and the need to recognize that it typically has a complex, but unstable seasonal and daily shape. This projection will not match actual realized generation output, sometimes over-estimating and sometimes under. How that affects NPC depends on whether it occurs for a wind plant owned by PacifiCorp versus under contract for the output at a fixed price per MWh. Positive variances from owned plants will tend to displace fuel costs or market purchases, reducing NPC, while such overproduction from a third-party wind resource under a power purchase agreement (PPA) could cause a NPC increase from paying the contract price, if that price is above PacifiCorp's marginal cost.

Note that even if there is exactly the predicted amount of wind over a moderate time-frame, a year or even a day, there can and will be NPC variances arising from what times within that hour, day, or month, etc. the wind blows and where because the time-of-day market prices avoided or incurred are fairly volatile. This problem is extremely common on a daily basis, as shown below in Figure 8. Thus, wind-based output, or any intermittent weather-sensitive renewable resource creates an inherent NPC variance issue even when it is forecast accurately on average. This may contribute to more NPC variances in the future as more wind and other renewable resources are added to the PacifiCorp system and more, older fossil fuel generating resources are retired.

Q. Does the unpredictable short-term variance of renewable generation impact NPC?

A. Yes. For example, Figure 8 shows that in 2021 actual hourly wind generation from PacifiCorp's owned wind resources deviated from forecast on average by 80 percent, using the absolute hourly deviations, even though on an annual basis, the actual wind generation deviated from forecast by only 7 percent. When this hourly variation occurs, the Company must either change its dispatch of other generating resources and/or adjust its market purchases and sales to meet customer demand. This shift in Company operations creates variances in NPC that are not able to be captured in a forecast model.

Figure 8



Q. Please describe how and why the Aurora NPC forecasting model is limited in its ability to work around the problems discussed throughout this section?

A. The Aurora model simulates the Company's system by optimizing mathematical projections of efficient operations and market transactions under perfect foresight of system conditions and prices, without considering the effects of market uncertainties that create additional unit commitment and dispatch costs and reduce the market participants' ability to find and execute the most profitable transactions. That is not to say that the perfect foresight includes what will actually happen, but as far as the model is concerned, the conditions you project are the only and exact ones that will occur, and then it finds the best way to optimize them. The model could be run for different conditions, like higher loads, but even the alternative scenarios will be perfectly optimized to the parameters of the scenario.

To be most reasonable and useful as an expected cost projection, simulations typically assume "normal" weather, load, and generation, without considering the impact of deviations from these average conditions. Simulations do not reflect non-standard, challenging, and erratic system conditions, such as unplanned outages, generation variances, or extreme weather conditions, such as heat waves, extended droughts, or polar vortexes that can drastically impact power costs and prices. Additionally, simulations do not capture inefficiency of fixed-size bilateral trading blocks. Most of the Company's monthly and day-ahead transactions are executed in blocks, as an example 16-hour blocks at 25 megawatt increments and are far less flexible and less profitable than the hourly transactions made available in the model.

Long-term wind and solar forecasts are unable to predict hourly, daily, and monthly variation, but must be simulated as being like average all the time, even though, after the fact, they are never like average in most time frames for the whole year. Forecasting NPC accurately within the Aurora model will become more problematic as more renewable resources are added to the PacifiCorp system along with other utilities in the region.

Lastly, actual loads depend on circumstances well beyond what a utility can forecast, especially commercial and industrial loads that can vary with tariffs, industry competition, and the price of non-electric commodity inputs to their production.

All of this simply reflects that there is never going to be a forecasting model or tool for projecting market balancing operations, that will not have NPC variances. Models are intrinsically smoother than real world conditions, and smoothness typically results in NPC variations. This exposure to variances will persist and will likely grow under the direction the industry is headed with an increase in variable renewable resources and the reduction of traditional base load fossil fuel generating facilities.

Q. Even though NPC has become more difficult to accurately forecast, is there still value in updating the NPC model?

A. Yes. Consistent with the final order in the Company's last power cost only rate case, updating the inputs in the model with the most up-to-date information, prior to rates going into effect, is good modeling practice and consistent with past Commission precedent.[15] Company witness Mitchell explains why updating the NPC forecast is necessary to include new resources in rates, and match the benefits of these resources that will be included in rates as part of the multi-year rate plan.

V. EDAM

Q. What is the EDAM?

A. The EDAM is an initiative by the California Independent System Operator (CAISO) to extend participation of a developed organized day-ahead, hour ahead and intra-hour market to the region. The EDAM will provide economically optimal and least-cost, resource schedules, startup/shutdown instructions, and other core functions integral to organized markets across the footprints of ISOs and regional transmission organizations.

Q. What are the benefits to customers of EDAM Participation?

A. As of 2025, the Company will begin participation into the EDAM as announced by the Company on December 8, 2022. Customers will see lower actual NPC resulting from EDAM participation with preliminary analysis suggesting that annual NPC across the EDAM footprint may decrease by approximately $543 million.[16] Through the EDAM, the Company's generation units will be optimally scheduled and dispatched using the CAISO's state of the art unit commitment and economic dispatch models. Additionally, the EDAM's automated, expanded footprint and optimized dispatch will replace the Company's isolated dispatch within its two balancing authority areas. Participation in the EDAM will benefit customers by

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[15] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.,* Docket No. UE-210402, Order 06 ¶123-138 (Mar. 29, 2022).

[16] CAISO EDAM Benefits Study, CALIFORNIA ISO (Nov. 4, 2022), *available at* http://www.caiso.com/Documents/Presentation-CAISO-Extended-Day-Ahead-Market-Benefits-Study.pdf.

reducing NPC through more efficient and economic dispatch, inter-regional transfers (i.e., exports and imports between EDAM participants), GHG revenue, and reduced reserve requirements, with relatively low ongoing operation costs, very similar to the benefits of the Energy Imbalance Market (EIM) but larger in scope.

Q. How is the EDAM related to the EIM?

A. Whereas the EIM is the extension of an organized, intra-hour market to the region by the CAISO, the EDAM is similar in concept but larger in scope and applies to the day-ahead, hour ahead and intra-hour timeframes (*i.e.*, EIM participation is required for EDAM participation and therefore the EDAM replaces the EIM). The combination of the EDAM and the EIM create a complete organized market.

Q. How, specifically, is the EDAM larger in scope than the EIM?

A. The EIM is an intra-hour market that dispatches a portion of the Company's total generation and executes market transactions to maintain intra-hour supply-demand balance.

The EDAM is a day-ahead, hour-ahead, and intra-hour market (a complete organized market) that will dispatch the entirety of the Company's total generation on a day-ahead basis, and again on an hour-ahead basis, and again intra-hour, while executing market transactions to maintain supply-demand balance across all three timeframes (day-ahead, hour-ahead, and intra-hour).

Q. How have customers benefited from the EIM since the Company's participation in 2014?

A. Since the inception of the EIM, the Company's customers have enjoyed savings of and reduction to NPC of $591 million.[17] Initial estimates show that participation in the EDAM will provide even greater benefits. However, participating in the EDAM also allows the CAISO to economically control and optimize a larger portion of the system.

Q. How does operation in the EIM currently affect the Company's economic control of NPC?

A. Without consideration of hedging transactions or long-term power/fuel contracts, through participation in the EIM, the Company still retains economic control over a majority of NPC. Although the EIM provides more economically efficient intra-hour dispatch, only a portion of the Company's total generation output and market transactions are optimized by the EIM. This is because intra-hour dispatch responds only to intra-hour changes in the net load (load less wind less solar) profile and these intra-hour changes in the net load profile are only an increment to the day ahead and hour ahead timeframes which, absent the EDAM, are economically controlled and optimized by the Company.

Q. Once the EDAM is operational, how will EDAM operation affect the Company's economic control over NPC?

A. The EDAM will economically control and optimize most of the day ahead, hour ahead and intra-hour Company generation and market transactions. This is a majority

[17] *Western Energy Imbalance Market Benefits as of 1/1/2023,* CALIFORNIA ISO, *available at* https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

of NPC (without consideration of hedging transactions or long-term power/fuel contracts) because transactions before the day-ahead timeframe are mostly hedging transactions along with resource sufficiency transactions[18] and reliability related activities.[19]

Q. Why are hedges or long-term contracts not considered in assessing the scope of the EDAM?

A. Hedging transactions and associated costs are designed to limit the risks and variability associated with market exposure and provide rate stability; they are not economic optimization transactions. Long-term contracts are typically either qualifying facilities and their associated generation (which the Company must purchase), purchased power agreements or coal supply agreements (which are few in number and easily accessible for prudency review).

Q. Given the Company's decision to participate in the EDAM, what does this mean for the Company's ability and incentivization to lower NPC?

A. As a result of the decision to participate in the EDAM, the economic operations of the Company's system on a day-ahead, hour ahead, and intra-hour basis will be managed by an ISO whose mandate is to leverage state of the art optimization software to minimize power costs for all market participants. Under this paradigm, the majority of the Company's NPC will be driven as low as the EDAM can achieve and, simultaneously, out of the Company's control.

[18] Bilateral transactions required to demonstrate resource adequacy in the day-ahead timeframe.
[19] An example would be responding to unplanned outages/derates and scheduling planned outages/derates.

Q. One of the stated objectives for the PCAM is to incentivize the utility to effectively manage or reduce power costs. With participation in the EDAM, do you believe the Company would meet this objective without the deadband and asymmetrical sharing bands?

A. Yes. When the Commission rendered its decision in the original PCAM and established a deadband and asymmetrical sharing bands, the Company did not participate in an organized market. With participation in the EDAM, the majority of NPC will no longer be under the Company's direct economic control but will instead be optimized by the CAISO using state of the art optimization software to minimize NPC. Accordingly, the Company will control costs by participating in the EDAM, not by minimizing costs through the day-ahead, hour-ahead, and intra-hour transactions that the Company controlled when the PCAM was created. In other words, when the economic control of NPC is simultaneously taken out of the Company's hands and guaranteed, by an independent third-party, to be as low as modern optimization techniques can achieve, there are very few cost controls left for the PCAM deadband and asymmetrical sharing band to incentivize.

Q. What are the PCAM related implications to cost recovery from the Company's participation in a complete organized market?

A. It is often argued the PCAM deadband and sharing bands are needed to incentivize the Company to lower actual net power costs through improved cost controls. In and of itself, participation in a complete organized market, overseen by an independent third-party operator and monitored for efficiency by an independent market monitoring agency, merits the elimination of the deadband and asymmetrical sharing bands because the market structure itself guarantees lower actual NPC through independent, automated, least-cost commitment and dispatch of the Company's system in the day-ahead, hour ahead, and intra-hour timeframes. Simply, when the control of NPC is simultaneously taken out of the Company's hands and guaranteed by an independent third party to be as low as modern optimization techniques can achieve, there are no cost controls left for the PCAM to incentivize.

Q. How are utilities in organized markets treated in terms of NPC variances in their cost recovery mechanisms?

A. Across the 35 states that have regulated electricity power supply, 20 operate in organized market regions. In those 20 states, across all the utilities that participate in these organized markets, all but 3 states have cost recovery mechanisms without deadbands or sharing bands and flow through 100 percent of net power cost variances. Missouri, Montana, and Vermont are the only states that do not have full flow through of NPC. Missouri has a 95/5 sharing mechanism, Montana has a 90/10 sharing mechanism, and Vermont has a 90/10 sharing mechanism.

VI. LACK OF CONTROL OVER KEY NPC DRIVERS

Q. What is the implication of the key drivers of NPC variations for the appropriate mechanism to allocate NPC risks between customers and the Company?

A. The key drivers of NPC variances, like deviations in load, renewable resource generation, and market spot power prices are outside PacifiCorp's control. Because no such mechanism or ad hoc adjustment exists to have a perfectly matched forecast to actual results, the difficulties are fundamental to the fact that this component of NPC arises on the margin in relation to both unforeseen conditions and how those affect the marginal positions of every other power market participant in the western interconnection that is able to trade with PacifiCorp.

Due to the fact that these drivers are so uncontrollable, and past variances have not been attributed to imprudent or inefficient practices by the Company, there is no improvement or benefit that can be expected or incentivized by not allowing NPC variances should be fully returned to customers or recovered by the Company.

Q. If all of these problems are inherent to forecasting and actual events in the industry, doesn't that just make them a part of normal business risk that should be incurred for customers or the Company?

A. No. While they are certainly normal to experience, it is not normal for them to be systematically disregarded by virtue of asymmetric risk-sharing and broad exclusions of NPC variances through a deadband and asymmetrical sharing bands. They reflect prudently incurred costs that are simply difficult to forecast. Thus, it is neither productive, equitable, or incentivizing to treat these variances as just a normal risk that should be absorbed by either the customers or PacifiCorp.

Q. Is there any incentive to customers or the Company by putting NPC variances at risk via the deadband and asymmetric sharing bands?

A. No. As noted below these costs cannot be mitigated by forecasting or hedging, and they are not the result of imprudent operational decisions. These are prudently incurred costs that are fundamentally uncontrollable, and therefore should be fully recoverable by customers or the Company for any variances between Forecast NPC and Actual NPC. Making either customers or the Company bear the variance costs when they cannot do anything material to reduce or improve them is simply punitive.

The sharing of NPC variances currently in place for the PCAM can unintentionally punish either customers or the Company for pursuing the benefits of renewable resources, where any NPC variance is simply a byproduct of being in the market with those resources.

Q. Would the Company's Actual NPC still be subject to a prudence review if the PCAM deadband and asymmetrical sharing bands were eliminated?

A. Yes. Actual NPC will still be reviewed for prudence during the annual PCAM filing, which is filed on June 15 each year. However, with participation in an organized market, the quantity of transactions to review would likely be less numerous because the majority of NPC transactions and decisions will be automated and optimized under the purview of an independent system operator. The remaining NPC transactions relevant for prudency reviews may become smaller by magnitudes and therefore more manageable in future annual PCAM filings.

Q. Can PacifiCorp mitigate NPC variances with better forecasting or hedging?

A. No. First, the forecasting methods that the Company uses for NPC are consistent with industry wide standards and are carefully applied and reviewed. Second, power cost production models are not capable of capturing the wide variety of unforeseen and random influences that will affect NPC. Even if such a model were available, it would not be possible to forecast with any confidence or accuracy the parameters for the randomness of uncontrollable factors that should be overlaid on it to improve accuracy. You could perhaps calculate a premium for an assumed level of variance based on history, but you would not get a better forecast of what will actually occur.

Likewise, hedging will not help much, if at all, for the purchased power part of the problem because the main difficulty is knowing the relevant volumes. Most commercially available hedges are for price protection of a given volume, allowing a utility or producer to hedge specific volumes for specific times. Thus, annual average output can be hedged, but not so much the costs of deviating from that average. The times when there will be an unplanned outage of a generating unit, or there will be more or less wind than in the past from a wind farm, or similar changes on other systems with which PacifiCorp trades, are fundamentally unknowable. Even options, which can be used conditionally, have fixed volumes and periods of allowable exercise. Hedges mostly help the volumes that you can reliably expect. Most of the NPC problem comes from the volumes you cannot plan for, except to know in general that they will happen.

VII. CONCLUSION

Q. Please summarize your conclusions.

A. As constructed, the PCAM does not accommodate the fact that due to more reliance on renewable resources, increased market participation, and the formation of the EDAM, there are irreducible variances between Forecast NPC and Actual NPC. PacifiCorp's increasing use of renewable resources and broader participation in regional power markets is a good thing, reducing NPC on average, but doing so comes with a side-effect of more exposure to short-term transactions that create large variances in NPC. Renewable generation is difficult to forecast, especially far in advance for rate setting and are also quite variable in the short term. These variances across the region tend to do so congruently rather than independently, creating shared conditions of overall shortfall or excess supply when they vary from expectations and pushing replacement power market prices far off of their prior expectations as well. It is also likely that utilities in the western interconnection move to a greater reliance on market-mediated coordination as more renewables are utilized in order to take advantage of geographic diversity and to share access to balancing resources which means more of the balancing costs in NPC will depend on actions of other utilities that are not part of the control or forecasts of the Company.

Q. Please summarize your proposal to the Commission.

A. I recommend the Commission approve a better solution for both customers and the Company through the elimination of the PCAM deadband and asymmetrical sharing bands, which would ensure that all prudently incurred net power costs are appropriately refunded to or charged to customers. Additionally, to preserve rate stability for Washington customers, I propose retaining the $17 million credit or surcharge threshold in the PCAM.

Q. Does this conclude your direct testimony?

A. Yes.