Exh. SJK-17T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-240006

DOCKET NO. UG-240007

(consolidated)

REBUTTAL TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, employer, and business address.

A. My name is Scott J. Kinney. I am employed as the Vice President of Energy Resources at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

Q. Have you filed direct testimony in this proceeding?

A. Yes. I filed direct testimony[1] providing an overview of Avista's electric and natural gas resource planning and energy supply operations. This overview included summaries of the Company's current electric and natural gas resource plans, an update on the Company's participation in the Western Resource Adequacy Program and Western Energy Imbalance Market, resource needs to support compliance with the Climate Commitment Act (CCA), an overview of the Company's Energy Resources Risk Policy, the Company's new Energy Trade and Risk Management (ETRM) system, and an update on the use of the Company's demand response contract with Inland Empire Paper (IEP). I also provided an overview of the Company's natural gas supply and resource plan. Next, I addressed new resource acquisitions from Chelan Public Utilities District (Chelan PUD) and from the 2022 All-Source Request for Proposals (RFP). Finally, my testimony concluded with a request to move to a 95/5 split in the Energy Recovery Mechanism and removal of the current deadbands.

Q. What is the scope of your rebuttal testimony?

A. My testimony addresses the following key areas: (1) Derivation of Net Power Supply Expense (NPE); (2) Forecast Error Adjustment, (3) Further Revisions to the Energy

[1] Kinney, Exh. SJK-1T.

Recovery Mechanism (ERM); (4) Energy Imbalance Market (EIM) Benefits; (5) Transmission Utilization and Costs; and (6) Climate Commitment Act (CCA) Compliance. Throughout these areas I discuss the Company's response to the issues raised by the Parties[2] in this proceeding.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits that accompany your testimony?

A. Yes. I am sponsoring Exh. SJK-18 – Letter from the Department of Ecology.

Q. Can you discuss revisions the Company is making after receiving the testimony of other parties?

A. Yes. Avista is proposing the following changes to its power supply filing:

(1) Avista agrees to adopt Staff's ERM proposal identified in Witness Wilson's testimony (JDW-1TR) with a 90/10 sharing, but with slight modifications to the deadbands. In surcharge years, the Company would absorb <u>$2.5 million</u> before the

[2] I will refer to the non-Company parties in these Dockets whose issues I respond to as follows: the Staff of the Washington Utilities and Transportation Commission (Staff), the Public Counsel Unit of the Washington Office of Attorney General (Public Counsel), and the Alliance of Western Energy Consumers (AWEC).

90/10 sharing begins and in rebate years the Company retains $2.0 million before the 90/10 sharing begins. This proposal maintains the Commission's policy of keeping a deadband in place, keeps the asymmetry of the deadbands, simplifies the ERM, addresses Company concerns about bearing disproportional risk associated with conditions outside of its control, and better aligns Avista's cost sharing as a percent of NPE with its peer utilities.

(2) The Company has rerun the Power Supply Model, updating all the usual components such as wholesale natural gas and power prices, new and short-term incremental contracts, non-gas fuel prices, and adopting certain positions of the parties that were discussed in their testimonies. (See Company witness Mr. Kalich's testimony (Exh. CGK-7T) for a description of the specific changes.)

(3) The "forecast error adjustment" will remain but is reduced from $65.8 million to $29.7 million using an average of actual 2021-2023 ERM variances, to address concerns expressed by the parties.

(4) Colstrip is removed from the 2026 NPE based on its 2025 net value (i.e., market value less fuel). No further power supply updates to 2026 would then be necessary.

Q. What were the updates or modifications made to the Power Supply Model?

A. Several modifications and changes were made based on concerns expressed by parties to this case. The Company updated wholesale electricity and natural gas prices to reflect a 3-month average of forwards for the period ending July 15, 2024 and included short-term contracts as of July 15, 2024. Also, Avista has updated natural gas and electricity transportation contracts to reflect the latest tariffed rates. We also modified or corrected some items identified by Staff Witness Wilson, including adding startup fuel costs from Aurora as they were not being reported. Second, revenues associated with a long-term wholesale power contract absent in our initial filing were added to Aurora. Third, the marginal dispatch price of Colstrip was modified. Fourth, Rattlesnake Flat Wind generation levels were increased. Finally, we included updated costs for BPA transmission and natural gas transport based on new tariff rates. Additional details of these modifications are provided by Mr. Kalich (Exh. CGK-7T).

Q. What are the estimated impacts of these changes to the Power Supply Model?

A. The total of the changes equals a reduction in system NPE from $175.1 million in our filed case to $119.0 million. Table No. 1 below details the impact of each change.

Table No. 1: Impacts Made by the Adjustments to Power Supply Expense

Item	$000s
Original Power Supply Expense	**175,100**
Adjustments	
Updated BPA Transmission	215
Updated Gas Transporation	95
Thermal Startup Fuel	365
Power Sale Contract	(450)
Colstrip Fuel Cost	57
Rattlesnake Flat Generation	(2,549)
Forcast Error	(36,100)
Changes to Market Prices & Contracts	(17,686)
Total Adjustments	*(56,053)*
Rebuttal Power Supply Expense	**119,047**

These changes to Net Power Supply Expense are discussed in the testimony of Mr. Kalich.

Q. What will Mr. Kalich be addressing on behalf of the Company?

A. His rebuttal (Kalich, Exh. CGK-7T) will provide additional details on Net Power Supply Expense (NEP), "error adjusted" EIM benefits, ERM changes, and changes to NPE because of the re-run of power supply to address the testimony of the parties.

II. DERIVATION OF NET POWER SUPPLY EXPENSE (NPE)

Q. What facts will have an impact on determining Net Power Supply Expense (NPE)?

A. There were several facts underpinning the Company's inclusion of a forecast error adjustment in this case in response to changing market conditions, and the likelihood they will continue to persist. Avista asks that the Commission to make explicit findings of fact with respect to each of the following items:

(1) Market fundamentals have changed due to the reduction in the amount and availability of longer-term bilateral trades, an increasing number of wholesale transactions made in organized markets such as EIM, changing composition of the market favoring more clean resources, state emission policy, the region's resource mix transitioning to more variable resources, and a reduction in the resource adequacy of the Northwest as load growth increases and more extreme weather events occur.

(2) A large forward premium now exists in the implied market heat rate (IMHR) that can overstate the operating margin of our thermal fleet in Aurora, increasing NPE by tens of millions of dollars. The IMHR is defined as the relationship between electricity and natural gas prices.

(3) The value of our thermal fleet in reducing forecast NPE has risen ten-fold, from $15-$30 million historically, to projections in this case of over $300 million.

Along with an increased value is increased risk to the Company that these values won't materialize.

(4) The market liquidity necessary to lock in thermal fleet value has substantially diminished which prevents us from monetizing what ultimately becomes the forecast error.

(5) The cost and volatility of collateral has increased resulting in higher costs associated with power supply hedging and optimization of resources when we can hedge.

(6) The Company's annual ERM balance for the last three years (2021-2023) has resulted in large surcharges of $16.4 million, $48.8 million, and $23.9 million, respectively, illustrating that conditions have changed significantly and the ability for the Company to properly set NPE in general rate filings is more difficult based on the factors discussed above.

Importantly, no party has contested these facts. These facts attest to changes mostly outside of the control of the utility and serve to support the inclusion of a forecast error to more accurately set the NPE in this case. They also support a modification of the ERM to better match the relative size of Avista and the associated risk to achieve the NPE set in rates.

Q. Do you agree with the representation by Public Counsel Witness Dr. Earle that there is informational asymmetry working in favor of the Company?[3]

A. No. The Company works, day in and day out, with our system and knows it best through our familiarity and working knowledge of it. However, in a rate case we must provide detailed data for intervenors to evaluate. This includes providing all input and output

[3] Earle, Exh. RLE-1CT at 9:15.

files used in our power supply model. The data development and modeling process follows a methodology generated over many years by the intervening parties who are generally most concerned with NPE. Our data and methods were on full display for rigorous scrutiny outside and inside of a general rate case, addressing a complex set of issues including our cost calculations, hedging practices and resource dispatching down to the intra-hour level. We have provided more information to support our NPE, in large part based on the prior input and agreement amongst the power supply workshop participants. Witness Earle was not a participant in that workshop process.

III. FORECAST ERROR ADJUSTMENT

Q. What is the nature of the question before the Commission regarding forecast error?

A. As stated in my original testimony there are many forces that can create forecast error, but markets tend to be the greatest driver – and it is outside of our control.[4] These forces interact in complex ways and often "work at cross-purposes" with regard to Avista's power costs.[5] This is intensely "fact dependent" and requires explicit/actual recognition by the Commission in arriving at the decision. I have previously alluded to the significant instability in the market and differences between 2022 and 2023: the "doubling" of Avista's natural gas fuel expense, resulting in a significant increase in error relative to the forecast (almost <u>four times</u> the error seen in 2021). In 2023, the deterioration worsened: Avista's lowest hydro year since the energy crisis of 2000, magnified the difference between

[4] Kinney, Exh. SJK-1T at 68, ¶¶15-16.
[5] <u>Ibid</u>.

the forecast and actual results, resulting in the largest ever delta between portfolio forecasts and actual costs.[6]

Given these significant disruptions in the power supply market, and to better capture what the evidence suggests is necessary to more accurately reflect power costs during the rate-effective period, Avista developed in its direct filing a "Forward (Forecast) Value," valuing various components of the Company's portfolio for each year based on five years' worth of historical forward market prices.[7] It then developed an "Actual Value" which valued those same portfolio components for those same years using actual index prices and positions.[8] The difference between the forecast and actual values for any given year yielded what it termed its "forecast error".[9] It then averaged the annual forecast error for the five years from 2018 – 2022, to yield a forecast error of $65.8 million (system).[10]

In the interests of full transparency on this issue, Avista separated out this feature of the pro forma power supply adjustment (the "forecast error adjustment") rather than attempt to integrate it within the complex Aurora model. (That attempt to create additional focus and transparency may have only served to confuse the position more than if it had simply been embedded in the model itself.) It is well to recognize that this further modification ("forecast error adjustment) to power supply expense is all part of the same overall pro forma

[6] Kinney, Exh. SJK-1T at 69:2-14.
[7] Kinney, Exh. SJK-1T at 67:7-12.
[8] Id. at 67:8-17.
[9] Although characterized as a "forecast error," that may carry the wrong connotation. That "error" is really just the difference (or delta) between the forecast value and actual value.
[10] Id. at 68:7-12. Company Witness Kalich incorporates the "forecast error" into the ERM "baseline." (Kalich Exh. CGK-1T at 34:1-6). (See also Kalich Exh. CGK-3 for the calculation of pro forma power supply adjustment.) Finally, Company Witness Schultz incorporates the pro forma power supply adjustment into the determination of the Company's revenue requirement deficiency. Eliminating this adjustment would, in and of itself, reduce Avista's overall proposal revenue requirement from $77.067 million to $34.884 million.

examination of power supply expense that is, itself, a regular feature of rate case filings. It is not an adjustment outside of the overall power supply adjustment.

It is important to set the "baseline" correctly (a factual determination), for at least three reasons: (1) to assure proper and timely cost recovery; (2) to convey price signals regarding changes in power costs (especially important in a market with dramatic price changes); and (3) to assure that the "risk allocation" method still produces fair results that do not unduly benefit or penalize the Company, or its customers.

Q. Notwithstanding the testimony of Staff, Public Counsel and AWEC, does the Company still continue to support an adjustment for forecast error?

A. Yes, but at a much-reduced level of $ 29.7 million, versus $65.8 million. Staff and the intervening parties testifying on forecast error universally dismiss it, going so far as to claim it is not a real power supply expense. Witnesses Earle,[11] Wilson,[12] and Mullins[13] each mistakenly suggest that the ERM itself somehow captures forecast error. The ERM does not capture forecast error; it simply allocates it through sharing bands. This is important to understand, the ERM allocates the NPE delta to parties; it neither addresses nor reconciles forecast error nor identifies who through the ERM is disadvantaged by it. When NPE does not reflect all normalized costs, the Company unfairly absorbs a significant share of the forecast error through deadbands and a 90/10 sharing. When NPE overstates normalized costs, customers absorb a significant share of the forecast through deadbands and 90/10 sharing. Getting the expected level of NPE right is therefore essential to a balanced and fair outcome of a functioning ERM (no matter how structured).

[11] Public Counsel Witness Dr. Earle, Exh. RLE-1TC at 4:6.
[12] Staff Witness Wilson, Exh. JDW-1TCR at 8:4.
[13] AWEC Witness Mullins, Exh. BGM-1T at 44:6.

Staff Witness Gomez in Docket No. UE-170485, mirrored our concerns over not setting NPE correctly and stressed the importance of an ERM having a base level of NPE set correctly: "… for the ERM to function properly, the baseline must be set at a level that provides an equal likelihood of power costs coming in above or below the baseline."[14] Based on the recommendation of Witness Gomez in that case, the Commission directed very extensive power supply forecasting workshops occurring over the 2018-20 period. The express goal of those workshops was to get a more accurate baseline.

Forecast error reflects underlying value unrepresented in other aspects of power supply modeling. Markets have changed drastically in recent years in the makeup of resources, with an increasing amount of clean energy but with a lower contribution to reliability. Also transformational are regulations around carbon in the Clean Energy Transformation Act and the Climate Commitment Act, and the manner in which how power is traded in the forward and spot marketplaces. Aurora modeling, standing alone, simply cannot reflect all these changes without some additional changes to input assumptions – changes that weren't envisioned in the Workshops or in the final agreed-to modeling methodology. Significant to this case, the Company has shown how the assumed <u>relationship</u> between gas and electricity prices in the forward markets <u>relative</u> to the spot market has drastically changed since those workshops. This is especially true with how Aurora now greatly overvalues thermal assets.[15]

Q. Notwithstanding the above, has the Company considered the testimony of the parties and revised downward its forecast error adjustment?

[14] Witness Gomez, Exh. DCG-1T at 8:4-6 in Docket No. UE-170485.
[15] The impacts of these specific market changes also affect our non-thermal fleet, but to a much lesser extent.

A. Yes, it has. After reviewing party testimony and having more time to evaluate the determination of forecast error that has always been present in historical rate filings, the Company is proposing to modify the forecast error calculation using a simpler method, one that accounts for offsetting factors, is known and measurable, and is based on "evidence such as contracts, receipts, ledger entries, or other proof that specifically identifies the dollar amounts involved with the overestimate of the value of its fleet or the resulting underestimate of its power costs."[16] These were the concerns raised in the Commission's order denying Staff's motion to dismiss.[17] Instead of calculating the adjustment to NPE based on the average annual difference of the calculated Forward (Forecast) Value and Actual Value for the five-year period between 2018-2022,[18] the Company is proposing to use the annual average of actual ERM variances for the past three years from 2021-2023. The proposed forecast error adjustment provided by the Company on rebuttal is $29.7 million (versus $65.8 million).

Q. Does this new methodology address concerns raised by Witness Earle that "the PFE does not consist of costs that Avista can demonstrate it incurred in the past and not recovered"?[19]

A. Yes, it does. Using an average of <u>actual</u> ERM balances removes any dispute about using a calculation to determine forecast error. Annual ERM balances are simply determined based on <u>actual</u> power supply expenses incurred by the Company. ERM balances are reviewed by all intervening parties and approved by the Commission annually through an established ERM review process, thus ensuring the accuracy of costs incurred. The forecast

[16] Order 07 at Paragraph 83 of Dockets Nos. UE-240006 and UG-240007.
[17] Ibid.
[18] Kinney, Exh. SJK-1T at 68:7-12.
[19] Earle, Exh. RLE-1CT at 7:13.

error adjustment, based on actual demonstrated costs, will increase or decrease NPE depending on how well the power supply methodology assumptions included in Aurora reflect actual experience.

Q. Does this new approach to calculating forecast error address the concern that the 2022 forecast error of $202.7 million skewed the calculation provided in direct testimony?

A. Yes. The new proposed method of using actual ERM variances addresses the high calculated value of $202.7 million in 2022 that was previously used in the five-year data set to set the annual average under the original methodology. The actual ERM variance for 2022 was $48.8 million.

Q. Does the new forecast error methodology address AWEC Witness Mullins' issue with using back-casting techniques to make an after-the-fact change to NPE?

A. Using actual ERM variances that have been reviewed and approved by the Commission in ERM filings addresses concerns raised by Witness Mullins[20] that back-casting techniques are valuable for assessing and potentially changing modeling assumptions but should not be used as an after-the fact plug to calibrate the end results. The Company recognized that applying actual power supply variances that capture all of the variables that can impact errors in determining NPE and that have been vetted through a regulatory process was a better approach then using a back-cast methodology.

Q. Is the forecast error biased against customers to favor the Company?

[20] Mullins, Exh. BGM-1T at 43:15.

A. No. Where the pro forma NPE is lower than costs incurred by the Company, the forecast error adjustment will be positive to address the under-collection. But the forecast error adjustment is self-correcting. Where pro forma NPE is higher than costs incurred by the Company, the forecast error adjustment will be negative to address the over-collection.

Q. In Order 07 of this docket denying Staff's Motion for Partial Summary Determination, the Commission identifies three areas of concern with the forecast error adjustment. Does the Company's modified proposal address these Commission concerns?

A. Yes. In Order 07, the Commission agreed with Staff that:

(1) "… the Company must show that the [forecast error] adjustment is: (1) known, (2) measurable, and (3) not offset by other factors,"[21]

(2) "… [a forecast error adjustment requires] sufficient evidence such as contracts, receipts, ledger entries, or other proof that specifically identifies the dollar amounts involved with the overestimate of the value of its fleet or the resulting underestimate of its power costs,"[22] and

(3) "[testimony supporting a forecast error adjustment] should provide evidence that it considered any indirect offsetting factors."[23]

While the Company believes its original proposal met these concerns, our revised proposal should remove all doubt. The revised proposal is based on three years of known deltas between authorized and actual costs based on data audited by the Commission and parties through our annual ERM audits. Forecast error therefore is based only on known and

[21] Order 07 at paragraph 82 of Dockets Nos. UE-240006 and UG-240007.
[22] Order 07 at Paragraph 83 of Dockets Nos. UE-240006 and UG-240007.
[23] Order 07 at paragraph 84 of Dockets Nos. UE-240006 and UG-240007.

measurable power supply factors, including the impacts of contracts, receipts, ledger entries and other proof. Offsets are otherwise inherent to this data and audit exercise and are captured with certainty.

Q. As revised, and by way of summary, how does the forecast error adjustment address Staff's concerns that it is not known, measurable, and does not capture offsets?

A. The <u>forecast error adjustment is known.</u> Conceptually, NPE delta is driven by variations in those costs making up NPE. For example, the use of median hydro and forward market prices define NPE that will differ based on actual conditions experienced in the rate year. Under the Company's revised proposal, the variation of these two components is contained within the other tracked aspects of power supply in the ERM. This defines the forecast error.

The <u>forecast error adjustment is measurable</u> because cost deltas between pro forma and actual NPE are recorded and then reviewed in our annual ERM filings. Thinking again about the examples of hydro and prices, all other things equal, differences from their pro forma assumptions result in a measurable delta between authorized and actual NPE.

The <u>forecast error adjustment captures offsets</u>. By relying on historical differences between the entirety of authorized and actual NPE, as demonstrated in annual ERM filings, all power supply expenses are considered. Where one or more aspects of power supply perform worse than in the pro forma (e.g., poor hydro conditions) others performing better (e.g., higher wind generation) offset that worse performance, potentially resulting in a lower forecast error adjustment. And where offsets are large enough, forecast error will result in a negative forecast error value, resulting in a reduced NPE in the Company's next rate filing. Mr. Kalich discusses these points in greater detail in his rebuttal testimony.

Q. Should forecast error be rejected outright because it is somehow not a "known and measurable" cost?

A. No. Forecast error is neither more nor less known than the many other assumptions making up our calculated NPE value. Power Supply adjustments are a routine part of rate-setting over the years and involve reasonable pro forma assumptions. These adjustments are not dismissed out of hand because somehow, they are not "known and measurable." The forecast error adjustment to the NPE is no more or less known and measurable than is the NPE itself.

IV. <u>FURTHER REVISIONS TO THE ENERGY RECOVERY MECHANISM (ERM)</u>

Q. Please describe your understanding of the positions of the intervening parties on the ERM.

A. Staff offers an ERM alternative with a single deadband of $3 million; retaining 90/10 (customer/Company) sharing beyond the deadband. AWEC and Public Counsel object to modifying the ERM at all, arguing that power costs have always been volatile. Without refuting Company testimony with evidence of their own, AWEC and Public Counsel do not credibly challenge, however, Company positions that: (1) markets have and are changing rapidly, (2) markets are changing in a manner that detrimentally affects the Company, (3) market changes are almost exclusively outside utility control, and 4) tools to manage market exposure (e.g., hedging) are limited and rapidly diminishing. Finally, and without addressing the specifics and differences in the Company's situation, AWEC and Public Counsel point to the recent order by the Commission rejecting modification of PacifiCorp's similar cost adjustment mechanism.[24]

Q. Based on the testimony of Staff, Public Counsel and AWEC, does the Company have a revised recommendation for the structure of the Energy Recovery Mechanism (ERM)?

A. Yes. We have evaluated their testimony, prepared additional analysis of similar mechanisms applicable to our peers, and now suggest modifications to the existing ERM structure:

(1) Accept Staff's recommended 90/10 sharing (versus 95/5 Company proposal),

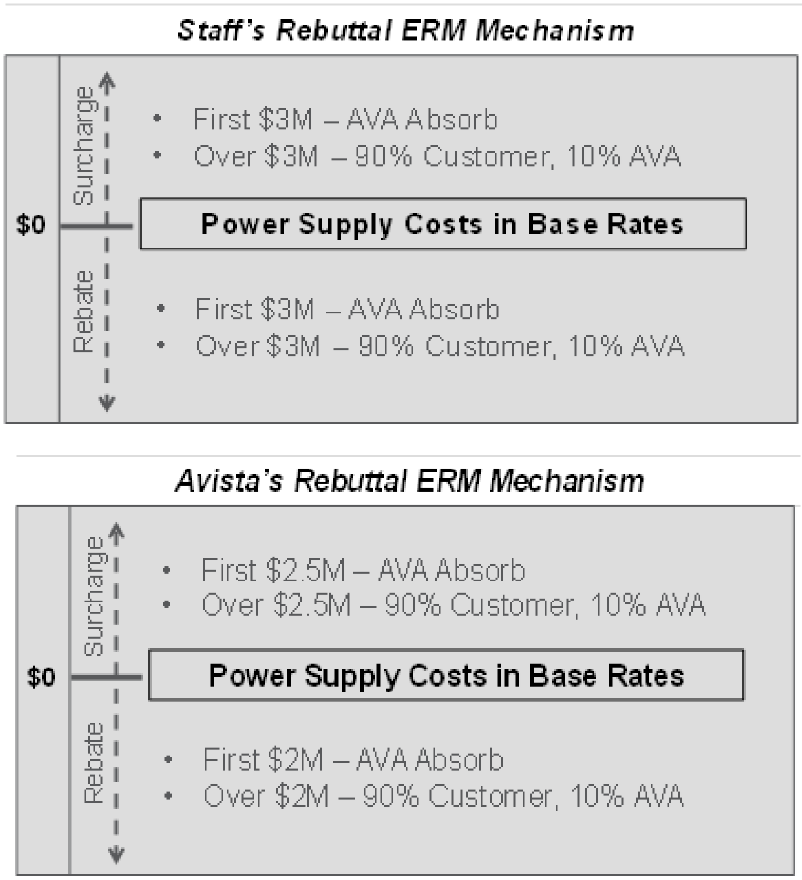
(2) Reduce the Staff proposed $3.0 million deadbands to $2.5 million when results are in the surcharge direction, and $2.0 million when in the rebate direction, and agree with Staff to eliminate the second asymmetrical sharing band that presently refunds 75 percent of surplus dollars to customers or splits equally surcharge dollars.

Q. Can you provide an illustration that compares the Company and Staff's proposal for the ERM mechanism?

A. Yes, a side-by-side comparison is set forth in Figure No. 1 below, for the sake of convenience:

[24] Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co., Dockets UE-230172 & UE-210852 (Consolidated), Order 08/06, ¶ 25 (Mar. 19, 2024).

<u>Figure No 1: Comparison of Staff and Avista's Rebuttal ERM Mechanism</u>



Q. How did you arrive at the new proposed deadband sharing levels?

A. The Company compared the relative size of our ERM deadbands to NPE with those of peer utilities and compared our market capitalization to reflect the relative risk to our business. Table No. 2 compares statistics between UTC-regulated electric utilities and their NPE.

<u>Table No. 2: NPE Comparison Among Washington UTC-Regulated Electric Utilities</u>

Utility	NPE ($mil)	Surcharge (Utility) Band ($mil)	Surcharge (Utility) NPE (%)	Rebate (Customer) Band ($mil)	Rebate (Customer) NPE (%)
PacifiCorp	190	7.0	3.7	8.5	4.5
Puget	950	28.5	3.0	32.0	3.4
Avista	107	7.0	6.5	8.5	7.9

Relative to NPE, the Company's sharing of deviations from authorized through the bands are about two times that of either PacifiCorp or Puget Sound Energy. This comparison demonstrates the fairness of moving to a lower sharing band for the Company.

Q. Is there another relevant comparison the Commission could consider?

A. Yes. A design using deadbands places higher risk on the Company for the first several million dollars of deviation from authorized, in theory offering a stronger incentive to manage costs. This means deadbands transfer much larger NPE variance risk to the Company relative to a 90/10 sharing band. It is therefore helpful to compare how strong, and therefore impactful, the deadband is to Company operations. As an example, PacifiCorp's business has a total capitalization of $24.3 billion, nearly 4.5 times the Company's $5.5 billion.[25] And yet, Avista's current $7 million sharing in deadbands, and the 90/10 split after the bands, is counter-intuitively, at the <u>same amount</u> as for PacifiCorp. This comparison demonstrates the fairness of a lower deadband for the Company. I discuss why Avista is fundamentally different than PacifiCorp later in my Rebuttal and why the Commission's recent decision for PacifiCorp should not be the end of the story.

Q. Does your proposal retain the present ERM asymmetry in favor of customers presently contained in Band 2 of the ERM?

[25] Source: 2023 MidAmerican Annual Report 10(k).

A. Yes. The Company's proposal on rebuttal retains the asymmetric design component of the ERM benefiting customers to a greater extent before 90/10 sharing occurs in years where actual power supply costs are higher than authorized. In surcharge years under the proposal, the Company absorbs $2.5 million before the 90/10 sharing begins; in rebate years the Company retains $2.0 million before the 90/10 sharing begins. This aspect of our modified proposal offers customers benefits beyond even Staff's proposal.

Q. Do you agree with AWEC and Public Counsel's contention that the PacifiCorp order prevents ERM modification for your Company?

A. No. Our circumstances differ materially from PacifiCorp. The risk inherent in our ERM deadbands is more impactful to us than to peers given our relative size. This alone should warrant modification of the ERM to provide more equal treatment of the utilities.

Beyond this, our modified proposal responds to the Commission's recent PacifiCorp Order:

> Without the guardrails of deadbands and sharing bands, the utility no longer has an economic stake in a major resource decision. As a result, the utility is more likely to ignore fossil fuel price volatility because it knows, regardless of price fluctuations, that it will be made whole by ratepayers. This approach creates a circumstance that one witness termed a "moral hazard" where one party is willing to engage in risky behavior or not act in good faith because it knows the other party, in this case the ratepayer, will bear the economic consequences.[26]

Our modified proposal retains the "guardrails" desired by the Commission, keeps the customer-focused intent of the asymmetry present in the second band of the existing ERM (in that it continues to provide more benefits to customers in surcharge years than we receive

[26] Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co., Dockets UE-230172 & UE-210852 (Consolidated), Order 08/06, ¶ 390 (Mar. 19, 2024).

back in rebate years), and the deadband size is adjusted to a risk level more in line with our regulated peers. See Table No. 3 below for a comparison of the ERM to Staff's proposals now in testimony. The Company's ERM proposal benefits customers more than Staff's proposal due to the retention of asymmetry in its structure.

<u>Table No. 3: Actual versus Proposed ERMs</u>

Actual vs Authorized Power Supply Expense ($millions)

		Tracked Power Supply Costs			Staff Proposal			Company Revised		
	Year	Actual	Auth.	Delta	Cust	AVA	Delta	Cust	AVA	Delta
	2011	101.7	120.9	(19.2)	(14.6)	(4.6)	1.8	(15.5)	(3.7)	2.7
	2012	114.2	128.9	(14.7)	(10.5)	(4.2)	1.8	(11.4)	(3.3)	2.7
	2013	123.3	118.2	5.0	1.8	3.2	(1.3)	2.3	2.8	(1.8)
	2014	108.7	118.2	(9.5)	(5.9)	(3.7)	1.7	(6.8)	(2.8)	2.6
	2015	96.2	113.8	(17.6)	(13.1)	(4.5)	1.8	(14.0)	(3.6)	2.7
	2016	81.3	89.8	(8.4)	(4.9)	(3.5)	1.6	(5.8)	(2.6)	2.5
	2017	82.3	88.5	(6.2)	(2.9)	(3.3)	1.2	(3.8)	(2.4)	2.1
	2018	82.0	97.6	(15.5)	(11.3)	(4.3)	1.8	(12.2)	(3.4)	2.7
	2019	97.0	102.5	(5.5)	(2.2)	(3.2)	1.1	(3.1)	(2.3)	2.0
	2020	85.0	102.5	(17.5)	(13.0)	(4.4)	1.8	(13.9)	(3.5)	2.7
	2021	112.3	96.0	16.4	12.0	4.3	(3.3)	12.5	3.9	(3.7)
	2022	121.1	72.3	48.8	41.3	7.6	(3.3)	41.7	7.1	(3.7)
	2023	131.8	107.8	23.9	18.8	5.1	(3.3)	19.3	4.6	(3.7)
All Yrs	11-23	1,337.0	1,357.0	(20.0)	(4.5)	(15.5)	3.4	(10.8)	(9.2)	9.7
Last 10	14-23	997.8	988.9	8.9	18.8	(9.9)	1.1	13.8	(5.0)	6.1
Last 5	19-23	547.2	481.0	66.2	56.8	9.3	(7.0)	56.4	9.8	(6.5)

Q. Witness Mullins quotes from a prior Commission Order where the Commission said, "deadbands and sharing bands are cost sharing tools that prevent the utility customer from absorbing the risk from fuel adjustment mechanisms, like the PCAM, that benefit utilities," and "that without the guardrails of deadbands and

sharing bands, the utility no longer has an economic stake in a major resource decision."[27] Does the Company's modified ERM proposal address this concern?

A. Yes. By retaining both deadbands and the 90/10 sharing, there is the potential for customers over time to benefit more than under the present ERM structure. By retaining customer-favored asymmetry in the deadband, the Company believes our modified ERM proposal addresses the concerns voiced by Witness Mullins.

Q. AWEC recommends that the Commission make no changes to the ERM and that it is functioning as expected.[28] Did Witness Mullins offer evidence to support his recommendation?

A. No. Witness Mullins offers <u>no</u> evidence contrary to the Company's case. Witness Wilson points out that in its recent PacifiCorp Order, the Commission, "encouraged parties to discuss when adjustments to the deadband/sharing band thresholds should be made."[29] This essentially is what the Company is now proposing in this case.

Q. Witness Mullins offers the following observation "…none of the issues Avista raises have any relevance to the ERM…power costs have always been volatile."[30] Do you agree?

A. No. Regarding the issues raised, Witness Mullins references docket numbers UE-230172 & UE-210852 as they pertain to organized markets and notes that the Commission was concerned by findings in those PacifiCorp cases. There was <u>no</u> evidence submitted by Witness Mullins of Commission determinations or conclusions based on the significant

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[27] Mullins, Exh. BGM-1T at 61:20 to 62:4 quoting Docket Nos. UE-230172 & UE-210852, Order Nos. 08 & 06 ¶¶ 330-404 (Mar. 19, 2024).
[28] Mullins, Exh. BGM-1T at 4:14-17.
[29] Wilson, Exh. JDW-1TR at 36:16.
[30] Mullins, Exh. BGM-1T at 60:17.

evidence presented by the Company in <u>this</u> case. We do agree that power costs are volatile. The magnitude of this volatility, changing aspects of our business, and the relative size of the sharing bands, for this case, however, support the proposed ERM modification in this case.

Q. Do you agree with Witness Mullins' suggestion that CCA compliance obligations are speculative and that "deviating from Commission policy and precedent to the detriment of ratepayers based on speculation is unreasonable"?[31]

A. No. While there is significant uncertainty around the absolute level of CCA compliance costs given today's market conditions and uncertainties, the aspects of the CCA rulemaking (such as the true-up mechanism), and the possible linkage with other markets, the CCA may actually increase Company costs.[32] While it is not possible to address CCA fully in this proceeding, because so many unknowns still exist with CCA, it is prudent, however, to recognize the risk that may be borne by the Company for these costs in the pro forma period, and to address them as much as reasonably possible in this proceeding with tools available to us – namely, by recognizing recent under-collection of costs by including a forecast error adjustment and modifying the ERM.

Q. Should the Commission adopt Staff's recommendation over Avista's modified ERM proposal?

A. No. While Staff's proposal is much improved from the current ERM, for reasons described in this rebuttal testimony, the Company's proposal is fair to the parties, demonstrates more value to customers, and still retains what the Company believes is the

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[31] Mullins, Exh. BGM-1T at 62:7.
[32] Under the CCA, the Company is permitted to mitigate CCA costs through the granting of no-cost allowances; however, it still is not clear exactly how many allowances will be granted or if they will equate to the entirety of Company emissions.

Commission's preference to credit customers more value through the deadband when authorized recovery is surplus to experienced costs.

Q. What did The Energy Project say about the ERM modification and how does the Company respond?

A. The Energy Project, in Witness Stokes' testimony (Exh. SNS-1T), stated that the ERM modification should be rejected because it places all costs on customers and they are not able to impact the market. It argues that through "…SB 5295, the Legislature directed the Commission to establish and maintain regulatory processes that measure and incent utility performance."[33] With its revised ERM proposal, Avista is recommending a modification of the ERM keeping an asymmetric deadband where the Company gets the first $2 million of rebate and absorbs the first $2.5 million of surcharges and maintaining the 90/10 sharing beyond those deadbands. As discussed earlier, this would bring the relative size of the ERM more into line with how the recovery mechanisms of the other regulated utilities and over time customers <u>could pay lower costs</u> than under Staff's proposal or the current ERM structure.[34]

Regarding Performance Based Ratemaking in SB 5295, the ERM has not been separately identified by the Commission as an area to apply performance measures which are geared towards evaluating how a utility performs. The incentive to perform is already part of the sharing mechanism.

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[33] Stokes, Exh. SNS-1T at 40:6-16.
[34] See Table No. 3: Actual versus Proposed ERMs.

V. ENERGY IMBALANCE MARKET (EIM) BENEFITS

Q. Please summarize your understanding of the parties' positions on EIM benefits in this proceeding.

A. Witness Earle states, "Avista's forecast methodology is fundamentally flawed and as a result systematically underestimates the value of EIM participation."[35] He recommends the Commission adopt an annual value equal to twelve (12) times the average of sixteen (16) monthly CAISO-calculated reported EIM benefit values falling within a 95th percentile band of those same historical values, or $20.7 million. AWEC Witness Mullins requests a downward adjustment to NPE of $3.0 million to reflect the value of GHG payments, as well as certain CAISO cost code revenues and costs he believes are not in Aurora.[36] Witness Wilson, through revised testimony, recommends a downward adjustment to NPE of $1.4 million.[37]

Q. What are the benefits of EIM to the Company as they pertain to NPE?

A. EIM benefits are created from 15-minute unit commitments (start-ups) and 5-minute resource dispatches based on market economics. Aurora modeling performed for more than 20 years to support ratemaking, has been based on <u>hourly</u> dispatch. EIM <u>intra-hour</u> prices afford the Company, on behalf of customers, an opportunity to vary generation modestly within the hour against a new market, accruing additional value from resources and thereby lowering overall NPE. In this case, the Company incorporated the same Aurora modeling methodology as Puget Sound Energy did to account for the ability to dispatch resources on a sub-hourly basis. The Company estimates an EIM benefit of <u>$6.6 million</u>, up from $5.6

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[35] Earle, Exh. RLE-1CT at 3:15.
[36] Mullins, Exh, BGM-1T at 54:12-15.
[37] Wilson, Exh. JDW-1TCR at 38:21.

million in our initial filing.[38]

Q. Is the Company adopting the EIM adjustments proposed by Witnesses Mullins and Wilson to the Aurora-defined estimate?

A. No. The Company is not adopting these adjustments.

Q. Will Mr. Kalich further elaborate in his rebuttal on the EIM benefit calculation and corresponding Aurora methodology?

A. Yes.

VI. <u>TRANSMISSION UTILIZATION AND COSTS</u>

Q. Does Avista still plan to use its Montana and BPA point-to-point transmission rights after transitioning out of Colstrip ownership?

A. Yes. Avista's last three Integrated Resource Plans (IRP) show acquisitions of wind in Montana to meet load growth and compliance requirements under the Clean Energy Transformation Act (CETA). Montana wind has a higher load factor than other wind regions and provides diversity with our existing Palouse Wind and Rattle Snake Flat facilities in Washington. Avista recently signed a power purchase agreement with NextEra for 97.5 MW of nameplate generation from the Clearwater Wind facility in Montana through a competitive bid process, which illustrates the value of Montana wind facilities. In the Company's current draft 2025 IRP, Montana wind is again included in the Preferred Resource Strategy within the next five years. <u>To facilitate the delivery of renewable resources in Montana to Avista customer load, the Company must retain its current Montana Intertie and point-to-point</u>

[38] The EIM benefit is inherent in 5-minute modeling. The EIM benefit was estimated by running Aurora in a manner that prevents redispatch within the 5-minute modeling periods. The EIM benefit will vary based on market prices input to the model.

<u>transmission contract rights with BPA.</u>

If the Company did not retain its current transmission rights, then that capacity would become available to resource developers or other utilities that are currently in Avista's interconnection queue and several other Colstrip transmission owners interconnection queues. There is strong demand for transmission capacity to move resources from Montana to West coast load centers. It is unlikely that Avista will be able to acquire new BPA transmission rights to deliver future resources, if it gives up its current capacity since new transmission facilities will need to be built. Avista would be at the end of the existing transmission service requests and there is no guarantee when new transmission capacity will be built and at what cost.

Holding this capacity also provides benefits to Avista customers through participation in the EIM and future Day Ahead (DA) markets. The lack of transmission capacity to other EIM and DA market participants will limit Avista's opportunities to transact in these organized markets, which significantly reduces participation benefits.

Finally, there are other regional transmission expansion projects being considered that would match up well with Avista's current Montana transmission capacity such as the planned Grid United Northern Plains Connector line that would provide transmission capacity from Colstrip to North Dakota. Avista is evaluating ownership in this regional project to leverage its existing Colstrip transmission capacity and gain access to Midwest wind projects and the Southwest Power Pool and Midcontinent Independent System Operator organized market footprints.

Q. Will current Montana Intertie and BPA point-to-point transmission rights provide value to Avista customers in the future?

A. Yes. Contrary to AWEC Witness Mullins testimony,[39] the value of maintaining existing transmission capacity, and even pursuing additional capacity, is growing as available regional transmission capacity gets closer to being fully subscribed, the regional power supply in the West tightens, load growth increases, and Western organized markets expand from hourly to day-ahead operations.[40] Actual transmission utilization does not always match full ownership or capacity rights but that does not mean there isn't value in maintaining or securing sufficient capacity to meet current and projected needs, both for economic transmission as well as reliable utility service. Transmission acquisition and development is lumpy and often must occur well in advance of actual need to ensure that adequate capacity is available to access markets, facilitate bi-lateral transactions with adjacent counter parties and integrate new resources. With long lead times to plan, permit and construct new transmission, it is important for Avista to maintain its current BPA transmission rights on the Montana Intertie and point-to-point capacity from Garrison to the Avista system.

Avista is able to redirect its BPA point-to-point transmission capacity from Garrison to other BPA delivery points to facilitate the delivery of energy from Avista resources, other market transactions and Western EIM transfers through the reallocation of this transmission to Energy Transfer System Resources (ETSR's) on the Bonneville Power Transmission Network. Avista will maintain the ability to redirect this point-to-point transmission after transferring Colstrip generation ownership which will provide tremendous flexibility and value to customers. BPA is also proposing to roll up the Montana Intertie transmission service with its network point-to-point transmission, giving the BPA Colstrip transmission contract

[39] Mullins, Exh. BGM-1T at 57-58.
[40] Mullins, Exh. BGM-1T at 57:17-19.

holders the same redirect ability on the BPA network.

Q. Does it make sense for Avista to maintain its current BPA transmission rights associated with Colstrip generation even after Avista no longer has an ownership share of the plant?

A. Yes. As discussed above, transmission ownership and contract rights are extremely valuable and necessary to ensure current and future load service. The exact location of new resources is not known until a competitive request for proposal process is conducted. However, having available transmission capacity to multiple adjacent utilities and regions will allow Avista to select the best available renewable projects in the region and eliminate the long lead time required to construct and build new transmission facilities. If Avista were to eliminate its BPA transmission rights associated with current Colstrip deliveries, then it is highly likely that none of the proposed renewable projects in Montana would be able to bid into future RFPs until additional transmission capacity is built at a much higher cost than maintaining the current contract rights. Also, the lead time to build transmission could be at least a decade based on other regional transmission projects that are currently going through the permitting and siting processes.

If Avista is not using all of its BPA transmission associated with current Colstrip generation to deliver energy to load, then the Company can resell unused capacity to other entities on a short-term basis and recover some of the contract costs. Revenue created from transmission resell will be returned to customers through the ERM. However, Avista will maintain the long-term capacity rights on these important regional transmission assets to ensure delivery of energy to customers well into the future.

Q. Why does the Company plan to continue investing in Colstrip

transmission assets?

A. As a Colstrip transmission owner, Avista must pay its share of system upgrades and annual maintenance costs per the Colstrip Transmission Agreement, and failing to pay would put Avista in contract breach. The Company identifies a tremendous value to customers in continuing to invest in the Colstrip transmission system based on the same reasons discussed above associated with maintaining BPA transmission rights on the Montana Intertie and point-to-point to Avista's system. Avista needs to have access to different regions to diversify its future renewable portfolio to meet CETA requirements, provide adequate system capacity and energy, maintain access to adjacent counter parties for bilateral trading, provide geographical diversity to wind resources, and have sufficient transmission access to maximize benefits in the EIM and future DA markets.

Q. Will Avista's Colstrip transmission assets be used and useful after the Colstrip generation is removed from its resource mix?

A. Yes. Avista strongly disagrees with the claim made by Witness Mullins that Avista has not provided evidence that it will continue to use its Colstrip transmission assets for Washington customers and therefore the assets will not be used and useful.[41] As previously stated, Avista's 2020, 2021 and 2023 IRPs showed Montana wind as a preferred renewable resource to meet future load growth and Washington State clean energy and emissions policy requirements because Montana wind sites provide higher load and capacity factors than other regional wind locations and provides diversity with our existing wind fleet in Washington. If Avista does not maintain its Colstrip transmission ownership, then it will significantly limit future renewable resource selection and trading opportunities resulting in higher future costs

[41] Mullins, Exh. BGM-1T at 58:9-21.

to customers. The cost, availability, and timing of new Montana transmission capacity is unknown. The risk to provide reliable, affordable, clean energy to serve Washington customers increases if Avista does not maintain sufficient and diverse transmission access within its service territory, with adjacent utilities and across the West. As discussed above with the Company's BPA transmission rights, Avista can resell any unused Colstrip transmission on a short-term basis and recover some of its ownership investment costs.

Q. Is there any other transmission-related testimony from intervenors you wish to address here?

A. Yes. Mr. Mullin recommends an NPE reduction of $206,000 to reflect the value of 100 MW of Company transmission rights to the California-Oregon Border (COB).

Q. Do you agree with this adjustment?

A. No. An adjustment for COB transmission was not included in previous cases and is not included in the agreed power supply modeling methodology. One primary goal of the Workshops on power supply modeling was to simplify inputs. The parties agreed to a balanced modeling approach that included a single wholesale electric market and a single wholesale natural gas market, instead of representing all markets used by the Company. The parties agreed this simplification was fair and no further adder for COB transmission was included in the power supply methodology.

VII. CLIMATE COMMITMENT ACT COMPLIANCE

Q. Does the Company agree with Witness Wilson's recommendation that Avista include CCA allowances costs in thermal plants dispatch?[42]

[42] Wilson, Exh. JDW-1TCR at 31:19-22.

A. No, we do not. Witness Wilson bases his recommendation on his "understanding" of the Department of Ecology's "intent" that is speculative, at best, entirely. The Company complies with the legislative requirements and intent of the CCA. It is not within the Department of Ecology's authority to establish a different "intent". Simply put, there is no requirement for Avista to include carbon prices and emission allowance obligation in all unit dispatch and power supply decisions. That rules do not prescribe operational decision-making is not by accident. Carbon price inclusion was deliberately limited to the planning and forecasting provisions of the CCA to affect resource acquisition decisions, not actual facility operations. Further, while Avista is obligated to follow the rules adopted by the Department of Ecology, only the Commission has the authority to prescribe how Avista makes decisions related to its generation facilities.

Q. Has this Commission indicated, through any policy or precedent for, how CCA allowance costs should be included in dispatch decisions?

A. No, it has not. Avista has participated in several workshop proceedings and provided multiple rounds of analysis which outline the impact of including carbon costs in dispatch decisions. In those workshops, Avista explained it did not include CCA allowance costs in its dispatch decisions.

To help illustrate how large the impact of including CCA allowance costs in thermal plant dispatch is, the Company ran a scenario based on its original filing. The result was a $73.3 million (system) increase (42%) in NPE,[43] caused by lower surplus sales and additional market purchases to serve load in cases where the "phantom" carbon cost prevents dispatching lower-cost generation.

[43] See Company's response to Staff DR 227 in Kalich, Exh. CGK-8.

Q. Does the Company agree with Witness Wilson's assertions that PacifiCorp's inclusion of CCA costs in dispatch decisions is a "more reasonable" manner of managing emissions?[44]

A. No. Witness Wilson's reference to PacifiCorp's inclusion of CCA costs in dispatch appears to only apply to the Chehalis natural gas-fired plant which is located in Washington and has a direct CCA emission compliance obligation. Similarly, Avista in this case included a carbon price in dispatch (as a phantom cost limiting dispatch, not as an actual cost raising NPE) for all Washington plants subject to CCA regulation. It did not include dispatch premiums in modeling for plants outside of Washington.

Q. Does the Company believe it is prudent to add the price of carbon to its resource dispatch?

A. No. Including CCA costs in dispatch would require base rates requested in this proceeding to be substantially increased. There are several arguments against including CCA allowance costs in dispatch:

(1) The CCA does not require carbon to be added to dispatch, which is an operational decision,

(2) The Commission has not provided any policy and direction to include carbon in dispatch decisions,

(3) As illustrated in the modeled scenario, adding the price of carbon could add $73.3 million (system) to the annual NPE,

(4) The Department of Ecology has not finalized the true-up mechanism, and Avista expects it could be granted no-cost allowances covering wholesale transactions

[44] Wilson, Exh. JDW-1CTR at 28:24 to 29:13.

made on behalf of customers, and

(5) Even if Avista is not given no-cost allowances for wholesale transactions, the Company has multiple ways to mitigate allowance requirements associated with these sales.

Where wholesale transactions occur in Washington but do not serve load in the State, then they are considered a "wheel through" and do not incur an allowance obligation. Avista estimates that 16% of its non-EIM wholesale transactions in 2023 were "wheel through" transactions. Avista can and has made wholesale sales associated with generation plants outside of Washington at the generator busbar or other locations outside of Washington State which excludes them from CCA obligations. Additionally, the Department of Ecology in a letter received in May 2023, acknowledged the "lesser-of-methodology" which allows wholesale system sales made by the Company to be associated with excess renewable energy at the Mid-Columbia trading hub, minimizing allowances obligations for these transactions.[45] With the granting of no-cost allowances to serve Washington retail load and the multiple opportunities to reduce allowance obligations associated with wholesale sales if not considered in the true up process, it would be imprudent to add the cost of carbon in Avista's resource dispatch resulting in $73.3 million (system) of additional cost to customers.

Q. Are there other considerations that factor into not adding the cost of carbon in Avista's dispatch?

A. Yes. Avista is a multi-jurisdictional utility with approximately one third of its

[45] See Kinney, Exh. SJK-18.

electric load in the State of Idaho. Adding a carbon price to thermal resource dispatch reduces wholesale revenue to Idaho customers not obligated to meet CCA compliance and who do not receive no-cost allowance grants from the Department of Ecology. Idaho customers pay a load-ratioed share of costs and should therefore receive a commensurate revenue share from wholesale transactions. Adding the cost of carbon to dispatch will significantly increase Idaho customer rates because the resources they pay for will be dispatched less often, creating lower surplus sales revenue to offset their rates. Including carbon costs in dispatch will incorrectly "export" Washington carbon regulations to the Idaho jurisdiction, in many or most cases, from generation neither located in Washington nor delivered to Washington.

Q. Does the Company agree with Witness Wilson's claim that it should actively buy and trade allowances?[46]

A. No. There is too much uncertainty in CCA rules, such as the true-up mechanism, and the law does not require the Company to optimize CCA allowances on behalf of customers in this way. Until CCA rules are complete, including guidance from the Department of Ecology in areas where the rules are vague, and the Company can assess the benefits and risks of actively trading allowances, it isn't prudent to speculate, as Witness Wilson suggests.

Q. Witness Wilson's comments seem based mainly on an "interview" with the Department of Ecology, focusing on the true-up mechanism and CCA's contribution towards carbon reduction. What instructions has the Department of Ecology offered Avista?

A. Despite numerous requests for clarification by Avista and other utilities

[46] Wilson, Exh. JDW-1TCR, at 21-22, 28.

through various channels, the Department of Ecology has not provided resolution on many standards by which electric utilities will be accountable under CCA. It is unclear whether it will be based on the forecast standard of WAC 173-446 or the compliance standard of WAC 173-441. (If the Department of Ecology gave guidance to Witness Wilson about the true-up mechanism's operation without otherwise sharing this information publicly, it would present an entirely different set of concerns about the Department of Ecology's processes.)

Absent publicly available guidance, it remains unclear if the Department of Ecology will essentially "claw back" or withhold a commensurate number of allowances in future distribution allocations as part of the true-up process. As such, it is just as plausible for Avista to assume the true up mechanism will apply to wholesale market transactions (in effect a "one-for-one" application) as it is to assume it will not.

According to Witness Wilson, "Ecology staff appears to view the active participation of the electric utilities in Washington's carbon allowance markets for it to function smoothly."[47] On a foundational level, the "appearance" is not an actionable directive. This statement infers the primary reason for electric utility participation is market liquidity – not carbon reduction. Carbon reduction for electric utilities is regulated by the Clean Energy Transformation Act and its Clean Energy Implementation Plan (CEIP). This is supported by the fact that only those utilities who are subject to CETA are granted no cost allowances to mitigate the cost burden associated with compliance with the program. Contrary to the statement by Witness Wilson, Avista's view of allowance costs is correct – namely, that the CCA is not intended to be the primary means of carbon reduction for electric customers.[48]

[47] Wilson, Exh. JDW-1TCR at 21:18 to 22:5.
[48] Wilson, Exh. JDW-1T at 22:6.

Q. Has Witness Wilson made any additional statements concerning the use of the CCA for dispatch in other cases?

A. Yes. In his testimony in the Puget Sound Energy general rate case filing, Witness Wilson explains his understanding of the position of the Department of Ecology based on their 2022 Publication 22-02-046, Concise Explanatory Statement Chapter 173-446 WAC Climate Commitment Act Program[49] versus his 2024 interview with the Department of Ecology.[50] Witness Wilson ultimately concludes that "…I cannot advise the Commission that Ecology's position is clear or that the recent federal court decision constrains Ecology from expecting allowance costs to be considered in dispatch decisions."[51] If Witness Wilson "cannot advise the Commission" for Puget Sound Energy to include CCA in its dispatch position, the Company cannot think of any reason why he should do so for Avista.

Q. Witness Wilson, as well as Staff Witness Erdahl, reference carbon emission reductions throughout their testimony as a primary support for the inclusion of carbon allowance costs in dispatch decisions. Is this consistent with Washington's <u>comprehensive</u> climate change policies?

A. No, it is not. As mentioned earlier, CETA is the primary climate change measure governing electric utilities. The intent of CETA is to reduce GHG emissions in the utility sector and the CCA brings the remaining sectors of the economy under a GHG emissions reduction program. Implying that the "intent" of CCA somehow supersedes CETA is inaccurate. Therefore, the recommendation of including carbon allowance costs in dispatch, leading to $73.3 million higher ($47 million Washington share) customer rates, is wide of the

[49] Wilson, Exh. JDW-1T at 18:17 to 19:8 in Dockets UE-24004 & UG-240005 (Consolidated).
[50] Wilson, Exh. JDW-1T at 16:11 to 17:7 in Dockets UE-24004 & UG-240005 (Consolidated).
[51] Wilson, Exh. JDW-1T at 25:9-11 in Dockets UE-24004 & UG-240005 (Consolidated).

mark.

CETA imposes a cost-cap calculation of a cumulative 2% burden annually. If Avista incorporates carbon allowances in its dispatch price, potentially resulting in up to $47 million in increased costs, this clearly exceeds the 2% CETA cost cap and does not align with CCA rules which seek to mitigate costs for customers. A $73.3 million (system) power supply cost increase is significant and is certainly not in line with the State's over-arching climate objectives and policies for electric utilities.

Witness Wilson suggests, engaging in auctions or bilateral markets to counter the impacts of reduced sales.[52] Not only are there no statutory or regulatory requirements for utilities to sell their no-cost allowances in at least the initial two compliance periods, to do so may be premature for the reasons described above.

In addition, the benefits associated with sales must first be prioritized to low-income customers per RCW 70a.65.120(4), which is not consistent with how the ERM is passed back/or charged to customers.[53] The ERM is distributed uniformly or "equally" across rate schedules, which does not meet the requirement to prioritize low-income customers. Given that equity is a priority for the Commission and is embedded within both CCA and CETA, this oversight is troubling.

Staff witness Mrs. Erdahl further emphasizes this limited focus in her "equity testimony," solely limiting her discussion to health impacts, yet making no mention of affordability. This limited view does not consider the impacts to vulnerable or highly impacted

[52] Wilson, Exh. JDW-1TCR at 16:14 to 17:2.
[53] The benefits of all allowances consigned to auction under this section must be used by consumer-owned and investor-owned electric utilities for the benefit of ratepayers, with the <u>first priority the mitigation of any rate impacts to low-income customers</u>.

communities regarding not only energy burden, but also energy security and energy vulnerability. Vulnerable populations are impacted to a higher degree by material bill changes resulting from policy changes as compared to those with a greater ability to respond to such changes. Recent Company surveys have shown that although reducing greenhouse gas emissions is important to Avista's customers, affordability is still the top concern by a large margin.[54] Beyond this, adverse health effects on our Washington customers are very small. – not only due to regulatory compliance with all air and other emissions standards, but by the fact that nearly all of Avista's thermal generation is located outside of Washington, tens to hundreds of miles away from Avista customers.

Q. Witness Wilson goes on to address prudency review in his comments.[55] Does the Company agree with his recommendation on prudency of allowance costs to be reviewed in each utility's respective NPE true up-proceeding?

A. Yes, we do agree in terms of allowance expense and revenue. There appears to be fundamental misunderstanding as to how allowance costs flow through the NPE. Operational decisions which result in expenses (fuel, purchases, etc.) requiring an outlay of funds and sales resulting from wholesale market transactions are separately tracked from CCA allowance costs. In accordance with the matching principle, expenses must be tracked in the same period revenue is generated. As part of an accrual accounting method, the matching principle requires that companies record expenses in the same period as the revenues they are related to, ensuring that each period's financial statements accurately reflect the true cost associated with revenue generated during that time. This principle is crucial for the accrual

[54] See TAC 4 presentation in Appendix A of the 2023 Electric IRP (Kinney, Exh. SJK-2a at 438-472).
[55] Wilson, Exh. JDW-1TCR at 24:14 to 27:7.

basis of accounting to provide an accurate picture of the Company's financial health by recognizing economic events regardless of when the cash transactions occur.[56]

Q. The question remains as to how the Commission expects Avista to record costs (or benefit) of its allowances such that it shows full CCA compliance on a calendar basis. How has Avista planned for this uncertainty?

A. The Commission has yet to provide formal guidance on this matter and has even questioned the appropriate manner to determine prudency in its CCA workshop series. In the absence of such guidance and considering the uncertainties surrounding the true-up mechanism, Avista has taken an understandingly cautious approach to ensure compliance and reduce price risk by managing compliance on a yearly basis. Avista's approach is conservative based on two factors: first, by using no-cost allowances to cover retail load, second, through offsetting the obligation associated with wholesale sales through wheel-through transactions, selling at the busbar and netting clean energy (lesser-than-methodology), specifically at the Mid-Columbia trading hub. Deloitte & Touche has audited Avista's quarterly accounting statements and has not raised any concerns.

Witness Wilson's speculation as to how the Department of Ecology may or may not allocate additional allowances and true ups aside,[57] the Company's strategy is prudent management of CCA allowance risk. It is well documented that variation of hydro is one of the primary purposes of the "true-up" and such differences are assumed and prudently

[56] The purchase (at auction or otherwise), or management of, carbon allowances is a balance sheet entry and does not impact customers rates until there is an actual allowance obligation or sale transaction. For the electric side of the business, expenses are recorded to account 509 (allowances) and flow through actual NPE and the ERM in that period. Each year in the annual ERM filing, the prudence of the previous years' expenses is evaluated. As such, evaluation for CCA is already part of the annual prudence determination.

[57] Wilson, Exh. JDW-T1CR at 21:5-10.

managed. In addition, recall that no-cost allowances are intended to "mitigate cost burden" and not only cover emissions.

Q Does Avista agree with Witness Wilson's contention about a CCA allowance prudence review being something that the Commission should anticipate?

A. No. Witness Wilson indicates that the Commission should anticipate a prudence review of CCA allowances because of the opportunity to increase Washington customer costs and the potential size of CCA costs possible in a future NPE true-up.[58] Staff assumes the Company will sell its no cost allowances even though that may not be the case, meaning there may not be any revenues from consigned CCA allowance sales to review for prudence.

Witness Wilson indicated that efficient prudency review of Avista's CCA allowance transactions could occur in an annual NPE proceeding or defer some or all CCA allowance transactions to the end of the four-year compliance period.[59] If the Company incurs any costs associated with the purchase of CCA allowances to cover the emissions associated with wholesale transactions, those costs will flow through Account 509 in the ERM. FERC accounting requires that all costs and benefits associated with a single transaction must be recorded during the same period and should be recovered (or passed back to customers) at the same time. This necessitates the need to evaluate the prudency of certain costs and benefits associated with the CCA in the annual ERM filing, <u>but only when we have incurred CCA allowance costs</u>.

Regarding the 4-year prudence review, electric and natural gas are not similar. It

[58] Wilson, Exh. JDW-1TCR at 24:7-12.
[59] Wilson, Exh. JDW-1TCR at 26.

makes sense for prudence of procuring allowances for natural gas LDC-related emissions to occur at the end of the compliance period because of the requirements to consign no-cost allowances, the requirement to turn in 30% of current year vintage allowances annually, and because natural gas companies must procure significant allowances to cover emissions. The electric situation concerning CCA allowances is very different in that we receive no-cost allowances to cover retail load but may still need to procure allowances to cover wholesale transactions, depending on how these transactions are actually executed and how the Department of Ecology implements the true-up. Because of the differences between electric and natural gas, prudence on the electric side likely will need to be reviewed both annually and then in totality after the 4-year compliance period due to the lag between forecasted and actual emissions.

Q. Does this conclude your rebuttal testimony in this case?

A. Yes, it does.