Exh. CGK-7T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-240006

DOCKET NO. UG-240007

(consolidated)

REBUTTAL TESTIMONY OF

CLINT G. KALICH

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Clint G. Kalich. I am employed as the Senior Manager of Resource Planning & Power Supply Analyses in the Energy Resources Department of Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

Q. Have you filed direct testimony in this proceeding?

A. Yes. My direct testimony[1] listed key components of the Power Supply methodology developed collaboratively in Power Supply Methodology Workshops (Workshops) completed as part of Order No. 07 in Dockets UE-170485 et. al. My testimony then described key inputs and assumptions driving power supply costs through the resultant methodology—including loads, outages, natural gas, and electricity prices—and provided a comparison to the current level of authorized net power supply expense (NPE). I detailed our methodology to reflect value from participation in the EIM intra-hour market. I also supported an adder to adjust for, among other aspects of NPE, the unprecedented overstatement of our electric generation fleet's value in the pro forma.

My direct testimony provided necessary context and further evidence supporting Company witness Mr. Kinney's testimony describing the importance of, and need for, eliminating Energy Recovery Mechanism (ERM) deadbands in favor of a single 95% pass-through of cost variances from authorized levels to customers. Finally, my testimony identified and explained the specific values proposed as pro forma adjustments to the 12-month ended June 30, 2023, test period power supply revenues and expenses, including the Retail Revenue Credit used in ERM deferral calculations.

[1] Kalich, Exh. CGK-1T.

Q. What is the scope of your rebuttal testimony?

A. My testimony addresses four key areas that tie to the testimony of Mr. Kinney: (1) Derivation of Net Power Supply Expense (NPE), on rebuttal; (2) Energy Recovery Mechanism (ERM) modifications, on rebuttal, (3) an updated Forecast Error Adjustment; and (4) Energy Imbalance Market (EIM) Benefits. 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:

The key points for the Derivation of Net Power Supply Expense include the following:

1. The Company's NPE on rebuttal is now $$119.0 million (system), down a total of $56.1 million from our initial filing of $175.1 million.
2. We updated Aurora assumptions to reflect more current forward markets and BPA transmission and natural gas transportation contracts ($17.4 million reduction); various errors identified by the Company and parties were reflected in the update ($2.6 million reduction), and a modified forecast error adjustment ($36.1 million reduction) was included.

[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).

3. With this update, no further power supply updates in this case.
4. The Company proposes a power supply workshop series after conclusion of this case, to include consideration of options other than Aurora as a modeling tool.

The key points concerning the proposed <u>ERM</u> modification are as follows:

1. Avista supports Staff's 90/10 ERM modification, but with asymmetrical deadbands of $2.5 million when in a rebate position and $2.0 million when in a surcharge position.
2. Reduced deadbands reflect levels more in line with PacifiCorp and Puget Sound Energy relative to their larger company sizes.
3. The parties did not materially provide evidence or refute facts presented by Avista that warrant ERM modification, including a 10 times increase in forecasted thermal fleet value unlikely to fully materialize due to collapsing values between forwards and spot market prices, the loss of forward hedging opportunities to be able to lock in future value, the impacts of CCA on costs, and that, by the Company being a price taker, it has no significant control over these outcomes.

The main points on the <u>Forecast Error</u> adjustment include:

1. The Company has modified its forecast error proposal to be based on 3 years of historical delta between authorized and actual NPE, reducing its value in this case from $65.8 million to $29.7 million.
2. Forecast error is an increase or a decrease to NPE, depending on the recent deltas between authorized and actual costs.

3. Forecast Error is an actual power supply cost and is no less known and measurable than the many other aspects defining NPE such as assuming median hydro, using 5-year historical averages for outages, and forward market prices. The Commission has long recognized its need to use assumptions and projections in deciding the power supply adjustment (as discussed below). The Forecast Error adjustment is simply one element of the overall NPE.

Finally, the main points about EIM benefits are the following:

1. Aurora modeling is performed using the approach of Puget Sound Energy and already embeds within it EIM benefits.
2. By running a "non-EIM" Aurora model, as Puget Sound Energy did, estimated incremental EIM value (i.e., above values we would otherwise achieve in bilateral markets were EIM to not exist) is $6.6 million (system.,
3. Further adjustments using data from CAISO EIM "counterfactual" and/or "cost codes/cost groups," as suggested by parties, are not appropriate for ratemaking.[3]

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

A. I am sponsoring the exhibits shown below:

- Exh. CGK-8 Staff Data Request 227
- Confidential Exh. CGK-9C Updated Dispatch Model Results
- Exh. CGK-10 Updated Pro Forma Adjustment Summary
- Exh. CGK-11 Updated Pro Forma Line Descriptions

[3] A review of cost codes indicates the potential for increasing NPE by $0.3 million; the Company is not proposing to adjust NPE upward to reflect this new finding.

- Exh. CGK-12 Updated Market Purchases and Sales, Plant Generation and Fuel Cost
- Exh. CGK-13, Updated Proposed Power Supply Base for ERM (p. 1)
- Exh. CGK-13 RY2 Updated Proposed Power Supply Base ERM without Colstrip (p. 2)
- Exh. CGK-14 Staff Data Request 192
- Exh. CGK-15 Public Counsel Data Request 307

Information contained in these exhibits was prepared by me or under my direction.

II. DERIVATION OF NET POWER SUPPLY EXPENSE (NPE)

Q. Has the Company revisited its NPE estimate, and if so, why?

A. Avista has revisited its NPE estimate to reflect intervenor positions that the Company supports, to reflect updated market prices and contracts, and to show the impact of a modified forecast error adjustment. The Company believes these changes offer an NPE more closely aligned with what should be included in final rates based on updated information and the concerns of the parties. With the update the Company is not proposing we further update values during the rate plan.[4]

Q. What updates were made to NPE?

A. The Company updated wholesale electricity and natural gas prices to a 3-month average of forwards for the period ending July 15, 2024. We updated short-term

[4] With the exception of removing Colstrip NPE values on or before January 1, 2026, as required by law. The removal of Colstrip in rate year 2 increases Washington NPE $51.6 million, ($54.2 million on a revenue requirement basis) on rebuttal, versus $59.5 million (revenue requirement) previously noted per Avista's direct case.

contracts as of July 15, 2024. Market prices now included in rebuttal are in Table No. 1 below.

Table No. 1: Rebuttal Market Prices

Period	AECO ($/dth)	Malin ($/dth)	Mid-C LLH ($/MWh)	Mid-C HLH ($/MWh)
Jan-25	2.28	6.76	88.23	102.73
Feb-25	2.29	5.67	79.58	86.74
Mar-25	2.15	3.58	48.76	47.93
Apr-25	1.97	2.71	43.71	38.67
May-25	1.90	2.56	31.09	27.43
Jun-25	1.93	2.82	27.78	28.36
Jul-25	2.00	3.56	44.38	79.88
Aug-25	2.02	3.64	63.92	112.29
Sep-25	2.05	3.57	62.71	93.33
Oct-25	2.21	3.20	75.20	78.58
Nov-25	2.55	4.84	84.49	86.33
Dec-25	2.85	6.90	99.90	108.94
Average	2.18	4.15	62.48	74.27

Q. Were other changes or modifications made?

A. Yes. In response to intervenor testimony, Avista modified or corrected for certain items identified by Staff Witness Wilson in response to Staff Data Request 227.[5] This request is included as Exhibit CGK-8. These items include: (1) startup fuel costs from Aurora not reported in our original filing; (2) corrected revenues associated with a long-term wholesale power contract not correctly input to Aurora in our initial case; (3) updated marginal dispatch pricing for Colstrip; (4) an increase to expected Rattlesnake Flat Wind generation levels; and (4) adjustments for new tariff rates associated with BPA transmission and natural gas transport contracts.

Q. What are the estimated impacts of these changes to NPE?

A. The total impact of the changes equals an NPE system reduction of $56.0

[5] Items d through g, i, j, and l.

million, from $175.1 million to $119.0 million. Table No. 2 details the impact of each change.

Table No. 2: Changes to Rebuttal Power Supply Expense (System)

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**

Q. Given the market changes described in testimony, does the Company believe the parties would benefit from another workshop series, after the conclusion of this case, to revisit the power supply modeling methodology? And if so, what aspects should be its focus?

A. Yes. While the 2018-2020 workshops were helpful in defining a methodology reducing much of the conflict over assumptions in Aurora, they didn't consider EIM and were unable to address or remediate drivers of forecast error. The Company would like to explore power supply modeling tools besides Aurora. The software is showing its age, and we have concerns over its adequacy to reflect dispatch complexities associated with CCA. There may be better software solutions to emulate markets (including intra-hour EIM) and resource operations. Finally, representations of each party have changed since those workshops, and the experts for Staff and Public Counsel in this case were not involved in the previous efforts. It would be productive to gather the parties and attempt to achieve consensus around a new modeling methodology to be used in our next filing before the Commission.

III. ENERGY RECOVERY MECHANISM (ERM)

Q. Mr. Kinney, on rebuttal, discussed various aspects of the ERM and testimony related to it. Do you have further observations?

A. Yes. I would like to specifically address some issues Public Counsel Witness Dr. Earle raised on behalf of Public Counsel.

Q. What is your response to how Witness Earle identifies and interprets the justifications used by the Company to support its original 95/5 ERM proposal?[6]

A. In attempting to discredit the Company's originally proposed 95/5 ERM modification, Witness Earle misunderstands the forecast error adjustment itself to include only market variability associated with generation assets. Much of his argument targets a forecast error adjustment the Company did not ever propose. Our forecast error adjustment proposal was a portfolio analysis considering the impacts of load, fuel prices, hydro output, variable energy resource output, and the performance of long-term PURPA and other contracts. Our proposed forecast error represents components of actual costs. His broader argument, that over the life of the ERM the average forecast error was small, is gravely mistaken. The 20-year *average* error Witness Earle cites to support the rejections of the ERM modification incorrectly masks very large forecast errors occurring year-to-year and over contiguous years.

Witness Earle also begins with a false premise by assuming that, in the Company's testimony, rates are set up to 35 months ahead of actual delivery and this somehow invalidates it. While the Company does note in testimony that rates are being set up to 35 months in advance, the forecast error analysis, and adjustment proposed in originally-filed testimony, is based on market conditions that evaluate exactly the timeframe Witness Earle implies. In

[6] Earle, Exh. RLE-1T at 10:7.

testimony he points out that the Company's forecast, "… go[es] out at most 14 months for the last month of RY1 (not 35 months)."[7] Our forecast error analysis included three months of forecast error for the first month of RY1, four months of forecast error for the second month of RY1, five months of forecast error for the third month of RY1, and so on. In developing our forecast error adjustment, we did not look at RY2 prices. Had we done so, almost certainly the forecast error would have been much larger.

Q. Do you agree with Witness Earle's second reason, regarding resource adequacy, to reject ERM modification?

A. No. Witness Earle acknowledges in his testimony that the Company's concerns about regional resource adequacy "may be true;"[8] but then goes on to cite the Company's IRP process, its Western Resource Adequacy Program (WRAP) participation expenses, and current portfolio length, as reasons to discredit our position. It is unreasonable to cite IRP processes, where future resource decisions are evaluated and scrutinized, and at the same time ignore the real and growing variability driven by market changes outside Company's control. While the IRP supports longer-term resource decisions, an IRP in no manner addresses the short-term nature of power supply cost variability in this case. Further, resource acquisition no longer is defined by Company preferences for limiting forecast error or reducing market exposure. Our resource choices are narrow, dictated by various state-level clean energy requirements, carbon reduction laws and other policies and regulations preferring variable energy resources. At the same time, the push for carbon reduction is disadvantaging prudently

[7] Earle, Exh. RLE-1T at 11:3.
[8] Earle, Exh. RLE-1T at 11:11.

acquired legacy resources already in rate base. This statement is not meant to disparage state carbon policy, but to point out its impacts for Avista and its customers.

WRAP will offer industry, and the Company, a potential opportunity to reduce operational concerns and manage growing market challenges before us, while spreading resource risks among a wider geographic area and implementing region-wide planning standards. It will begin no earlier than 2028, and therefore is irrelevant to this proceeding as this case pertains to Company evidence supporting the need for ERM modification <u>at this time</u>. Further, WRAP is not a market mechanism the Company will be able to leverage to reduce the impacts of market dynamics. WRAP's purpose is to minimize risk of load loss in the region by using common planning methodologies and resource capacity calculations, ensure the region has enough supply to meet forward critical season demand, and to provide a backstop mechanism for participants to access capacity and energy when operating conditions occur beyond what was planned for.[9]

Finally, Witness Earle's argument fails to recognize a utility's obligation to serve, where it must build or acquire sufficient resources to meet customer peak demand. Meeting this obligation with resources deemed prudent in previous cases before this Commission creates a natural length in our portfolio under most conditions. We have excess energy to sell when average customer demand is lower than peak demand. The Company included a forecast error in this case to address the difficulty of modeling the value of this excess energy in the current market conditions. It might seem counter-intuitive but were the

[9] The Western Power Pool states, "the WRAP is the first regional reliability planning and compliance program in the history of the West. It will deliver a region-wide approach for assessing and addressing resource adequacy and provide an important step forward for reliability in the region."
See: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

Company in a short position instead of its current long position supported by significant natural gas-fired assets, the urgency of an ERM modification might be less of an issue.

The rising variability of this surplus position's value in determining NPE is a major component in our request for the ERM modification, as NPE forecasting methods presently overstate value. Without such an ERM modification as proposed here, the Company would be unduly burdened with costs that it will have to absorb.

Q. Witness Earle concludes that "Avista's complaint about market liquidity is unreasonable."[10] Did Witness Earle offer any actual evidence to disprove the Company's position that market illiquidity supports ERM modification?

A. No. Witness Earle, prior to that observation, stated that "this [not making forward purchases] is concerning and surprising given the ability of other utilities to buy electric power forward."[11] Without evidence, Witness Earle's statement is simply conjecture from someone who has never run an electric system. One can only speculate, but maybe he is confusing long-term purchases, or acquisitions made by others that do not meet the more complex needs of an organization with large hydro variability and surplus in its natural gas-fired portfolio. The Company would gladly operate in a market where it can readily make forward electricity purchases and provide beneficial sale transactions on behalf of customers and the Company as in the past. However, <u>that market for electricity has fundamentally changed</u> and those opportunities do not exist today, a fact seemingly not recognized by Witness Earle.

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[10] Earle, Exh. RLE-1T at 13:2.
[11] Earle, Exh. RLE-1T at 13:1-3.

Q. Do you agree with Witness Earle that the CCA is not a reason to modify the ERM?

A. No. Witness Earle offers no specific solutions to counter the underlying facts of this case that:

1) the CCA law is new,
2) key aspects of the CCA law are still not fully decided (e.g., allowances true up, allowance consideration in dispatch),
3) the CCA provides that utilities and customers should not bear additional cost burdens from the law, as utility decarbonization in Washington is already being regulated through the CETA, and
4) the current market for CCA has a great deal of uncertainty with a citizen's initiative to repeal the law, as well as Ecology greatly accelerating its plans for injecting allowance hold-backs originally intended for the entire 3-year compliance period into the first few auctions in an attempt to stabilize prices.

<u>The Company has no means to lower NPE through actions under the CCA</u>. It is only a matter of what the unknown costs will be. CCA costs presently are defined as NPE and flow through the ERM. As CCA wasn't intended to increase utility costs because CETA develops a clean supply of electricity, the Company should not be responsible for a large share of them. As CCA almost certainly will increase NPE, modification will help mitigate the issue by reducing Company's unreasonable exposure to CCA costs through the ERM.

Q. Does Witness Earle's argument against ERM modification—i.e., weather not being a new phenomenon—support the continuation of the present ERM structure?

A. No. Weather clearly is outside of the Company's control, and variability has always existed. However, the variability in NPE we are experiencing today is not caused primarily by weather changes. Instead, it is caused by the many other new and changing aspects of the business outside of our control, such as how the value of our gas fleet collapses (relative to its valued modeled in Aurora) as we approach real-time operations.

Q. Do you agree with Witness Earle's suggestion that before altering the ERM the Company should provide a comprehensive report on its hedging policies and practices?

A. No. Avista already provides this information to the Commission and has done so for some time and Witness Earle has not previously participated in that review. Those policies are largely guided by Commission policy. Further, issues presented in this case will not be solved by modifying hedging policies and practices. Already it has been shown that Witness Earle presents no evidence to refute the primary reason hedging has become less relevant in today's marketplace—the market liquidity for forward hedging has diminished, preventing the hedges traditionally relied upon to mitigate some risk of costs varying from forecast.

Q. Witness Earle suggests that there are many ways in addition to hedging to control NPE such as maintenance outage scheduling, minimizing forced outages and improving heat rates.[12] Does the Company manage these aspects, and are they material to the growing variability and risk the Company cites in this case?

A. The Company already has a mature generation asset management plan, with staff specifically dedicated to maintenance outage scheduling, and we always seek further

[12] Earle, Exh. RLE-1T at 14:1.

refinements in these areas. We regularly evaluate existing and new technologies to upgrade heat rate and other performance capabilities of our thermal fleet when the opportunities arise, and when they make economic sense to implement. While these areas provide means to lower NPE for customers, they really do not affect in a material way the aspects of growing risks beyond Company control. If our practices became imprudent, and plants went out of service for extended periods of time, NPE would grow significantly. But they have not, and outages aren't the driver of the risks we've been discussing here. Beyond stating the obvious that better plant performance will lead to better outcomes, Witness Earle offers no actual evidence that the Company does not prudently manage its plant at this time or his suggestion will materially impact risks presented in this case. In fact, they won't.

IV. FORECAST ERROR ADJUSTMENT

Q. Can you summarize your understanding of the witness positions against the forecast error adjustment?

A. Yes. AWEC Witness Mullins explains that the Company is highlighting with forecast error a modeling bias.[13] Yet he disagrees with using backcast models to validate performance. He goes on to state that backcasting is useful to identify potential modifications to a model to make it more accurate, but using the resultant values can lead to more inaccurate forecasts. No evidence is presented by Witness Mullins to illustrate his beliefs or that otherwise conflicts with Company's own analyses.

[13] Mullins, Exh. BGM-1T at 43.

Staff Witness Wilson[14] views our forecast error adjustment as a "pre-payment" based on historical trends which he believes is a recovery of a revenue requirement that does not yet exist.[15] He goes on to express an opinion that hedging would reduce this variability, that many of the drivers of NPE are not new, and that our position as a net seller in the market is an enviable position to be in. He provides no alternative to refute Company calculations or address how hedging has become less available to us. Extending Witness Wilson's logic to our current situation, it follows that the loss of hedging opportunities demonstrated by the Company only serves to increase volatility.

Public Counsel, for its part, through Witness Earle, rejects the forecast error adjustment in its entirety. He argues that forecast error is not a separate cost and since it is a modeling change, that disqualifies it from consideration. To support his position, Witness Earle presents a misleading 20-year aggregate error rate, discussed below.

Q. Do you wish to correct any misunderstandings you see in the parties' descriptions of your forecast error proposal?

A. Yes. It is important to ensure that parties to this case, and the Commission, understand the breadth of the forecast error adjustment and its supporting analysis, to understand <u>what it is</u> and <u>what it is not</u>. Witnesses Earle and Mullins describe the work as being only a mark-to-market valuation of our generation portfolio. Yet the analysis goes well beyond the generation portfolio. While some of the statistics presented highlight the value of our thermal assets in this case, and how their net value to customers has increased by ten-fold or more relative to past filings, the forecast error adjustment proposed is a <u>portfolio-wide</u>

[14] Wilson, Exh. JDW-1TCR at 9:10.
[15] In fact, and as is described later in testimony, the forecast error adjustment can be a discount to NPE based on historically-experienced conditions.

evaluation. This includes our generation assets, the variability of our power purchase agreements inclusive of our wind and solar resources, variation in our hydro assets, market conditions, and load. In other words, we capture the entire portfolio, not just generation. This means the analysis reflects the diversity of our portfolio to the extent it exists. For example, when prices fall from the base value projection, generation assets are worth less and load costs less to serve. When prices rise, load service costs rise, but so does our generation value, offsetting costs. If the hydro fleet generates less than the median water included in power supply modeling, but wholesale prices rise to reflect the high correlation across the Northwest of hydro outcomes, the higher value of our thermal assets can help "buy down" the higher costs of replacement power.

If the Company had only modeled the generation portfolio, it would be easier to agree with some of the concerns presented by Witnesses Earle and Mullins. But this is not what we did.

Q. Do you have any additional specific concerns with the basis by which Witnesses reject the forecast error adjustment?

A. Yes. I have several concerns with the conclusions reached by AWEC, Public Counsel and Staff, and will address each Witness in turn.

Q. What are your observations and concerns with the statement made by Witness Mullins that the market value of a generator changing with market conditions "does not necessarily equate to an increase or reduction to power supply expense"?[16]

A. First, I agree with his general statement that one cannot use a single variable to define forecast error. However, Avista did not base its forecast error estimate on the single

[16] Mullins, Exh. BGM-1T at 42:5.

factor of generator value, as discussed above. As Witness Mullins explains in testimony, there are offsetting impacts in a portfolio analysis like that performed by the Company in this case: impacts that Avista's NPE explicitly includes are the benefits of lower prices on serving load, higher hydro generation reducing purchased power need, and freeing up thermal generation for surplus sales.

Second, it is important to consider the multi-faceted interactions between the following:

- load and absolute electricity and natural gas market prices,
- the relationship between electricity and natural gas prices (the IMHR) due to our large on-the-margin natural gas fleet and natural surplus position,
- the amount of water available for generation in our hydro system,
- the level of variable energy resource performance,
- the levels of forced and planned outages, and
- the performance and market-relative purchase and sale contracts.

<u>Even with all these interactions, this case is dominated by one new factor entirely outside the control of Avista</u>: the implied market heat rate (IMHR). While Witness Mullins incorrectly represents our forecast error adjustment as including <u>only</u> generation fleet performance, he does correctly identify the primary driver of forecast error in these market conditions as our forecasted value of surplus sale net revenues (i.e., sale price less fuel costs) from natural gas-fired facilities.

In summary, Avista's broad consideration of portfolio variability drivers demonstrate significantly increased Company risk in today's market conditions, conditions almost entirely outside control of the Company. Though driven considerably by generation portfolio variation, Avista's forecast error considers broader portfolio diversity in defining it.

Q. Witness Earle states that through 2022, "Avista has only had a 3.3 percent aggregate error rate"[17] of $57.4 million on NPE of $1.751 billion. Do you agree that this historical comparison represents accurate forecasting of net power supply expenses?

A. No. While Witness Earle considers a twenty-plus year period over which to compare forecast results, companies like Avista cannot operate their businesses like that. Investors require stable performance year to year, even quarter to quarter. It is unreasonable that the Company should wait 5 or 10 years to be made "whole" through the ERM when the primary driver is real costs that can be reflected through a forecast error adjustment. The forecast error adjustment can be a positive (raising NPE) when market conditions demonstrate that the modeling methodology is under-reporting costs and negative (lowers NPE) when market conditions demonstrate that the modeling methodology is over-reporting costs. It works both ways.

Q. Do you agree with Witness Earle's claims, that his Figure 1 disproves the Company's contention that power supply costs cannot be forecast accurately?[18]

A. No. Historical errors of the authorized NPE are shown in Illustration No. 1 below. Shockingly, Witness Earle is implying that successful forecasting would carry the following caveats from an analyst presenting their results: "this is my annual forecast, I will benefit from being able to review and update it every year or two (i.e., at each rate filing), it will be incorrect by an average of over 20% each year and by as much as 75% in a given year,

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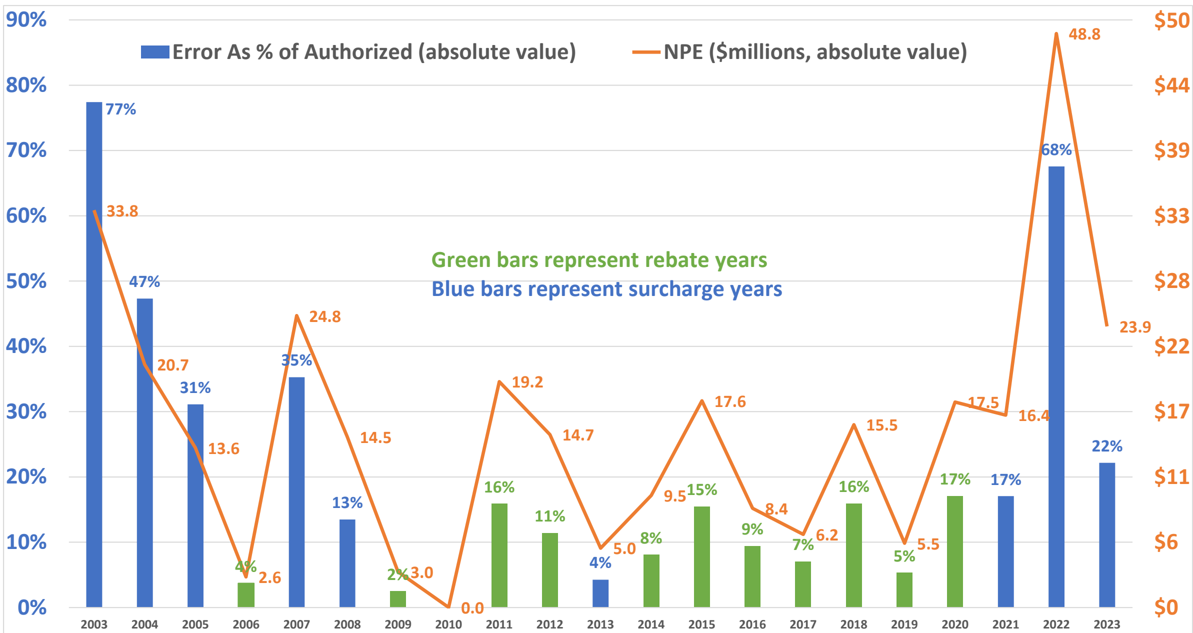
[17] Earle, Exh. RLE-1T at 5:8.
[18] Earle, Exh. RLE-1CT at 6:5 to 7:2.

but over 20 years the cumulative error will net out to be around 3% or 4%." Those caveats would make such a forecast unacceptable to management. They also should make the forecast unacceptable to the Commission.

<u>Illustration No. 1: ERM Historical Forecast Error as Share of NPE</u>



Further, by suggesting the history of forecast NPE is accurate, Witness Earle is going against a long record of acknowledged challenges in forecasting Avista's NPE. The Commission found Staff-sponsored testimony in 2017 on the challenges of forecasting NPE compelling enough to accept its recommendation for a multi-party workshop on better forecasting NPE for Avista. That effort lasted almost three years and subjected the Company's forecasting methods to a deep level of scrutiny and resulted in suggested changes that were implemented and used in this case. (Unfortunately, while Public Counsel did participate in these workshops, Witness Earle was not in attendance.) The parties did <u>not</u> identify items within control of the Company that would yield better results beyond some modification of the modeling methodology. Yet the evidence shows that even with the extensive workshop efforts, which included active participation by Public Counsel throughout and a new forecasting methodology intended to improve forecast accuracy, the forecast error continued at similar or even greater levels. Aurora modeling does not adequately capture the effects of the new market dynamics discussed herein.

This shows that even with an extensive multi-party workshop review of Avista's forecasting methods, which also included a review by consulting firm E3, the error exists and continues to be outside Company control. Conditions exist well beyond the ability of even the multi-party workshop participants to address.

Q. Do you agree with Witness Earle's argument using an example from your workpapers of 2022 NPE being calculated as $202.7 million, and that "such absurd results should be rejected and demonstrate, conclusively, that the PFE *(FE)* is not an actual cost and should not be recovered as if it were actually incurred?"[19]

A. No. Company testimony clearly explains how the NPE covers major aspects of power supply, not just the thermal plant performance that Witness Earle focuses on. The calculation does illustrate how market price variability, the implied market heat rate (IMHR), hydro variability, wind and solar variability, other contract (e.g., PURPA contract) variability, and load variability affect costs.

Q. Does the magnitude of the individual year pointed out by Witness Earle disprove the importance or benefit of a forecast error adjustment?

A. Not at all. When our case was prepared in the fall of 2023, we were reacting to a significant increase in forecast error, with 2022 being almost 50% higher than any other year in history and triple the forecast error of 2021. Our power supply modeling indicated we would

[19] Earle, RLE-1CT at 4:20 to 5:2.

be building even greater error into this case due to growing IMHR in the forward markets, meaning our exposure would grow. If market condition effects aren't reflected in NPE in some way, the result would be a gross underestimation of costs and a biased result. The Company would absorb $10 million through the two deadbands and then 10% of anything beyond that amount. In retrospect, a simpler approach, such as averaging historical errors in NPE (which the Company is proposing on rebuttal) might have been more appropriate. I will discuss this approach in more detail below as being our preferred approach on rebuttal.

Q. Do you agree with the contention made by Witness Earle that the forecast error concept proposed by the Company contradicts previous statements by Avista that modeling changes are adopted only after significant vetting and Commission approval?[20]

A. No. Avista did not introduce the forecast error by changing modeling. The workshop defined methods of defining data and processes for running the Aurora dispatch model only. It did not address many other items pro formed into every general rate case. Mr. Kinney explained why we made the adjustment explicit outside of the model and highlighted it for the parties to this case:

> **"Q. Could the Company address this discrepancy in Aurora?**
>
> A. Yes. We could adjust the relative margins between Forward (Forecast) value and expected Actual value price deltas. Aurora would then reduce our NPE to account for the difference. This approach was not part of our methodology agreed to in the power supply cost modeling workshops. The Company decided it was better to show the value in testimony as a single adjustment rather than translate the results of the analysis into a price dataset that would bury the impacts within Aurora." (Kinney, Exh. SJK-1T at 71:8-14)

[20] Earle, Exh. RLE-1CT at 5:3.

By explicitly calling out this adjustment separate and apart from Aurora, Avista hoped to provide additional transparency on this important issue.

Q. Do you agree with Witness Wilson's assessment that forecast error is not the difference between actual revenues and costs because if it were there would be no need for the ERM?[21]

A. No. A forecast error adjustment is only included to get the expected level of NPE correct under normalized conditions. NPE forecasting, especially the aspect of identifying the appropriate prices upon which to base the forecast on, always has been a challenge. In the Company's 2018-20 Workshop, the parties discussed this issue and potential solutions at length. Even with agreement on a methodology there wasn't an expectation that forecast error would disappear. No actions available to the Company were identified at the time. Since then, the problem of incorporating additional market dynamics has made the situation untenable without some sort of further adjustment.

Q. Didn't the Workshop consider all major factors the Company faces today in forecasting NPE?

A. No. The Workshop did not benefit from an understanding of the past few years' divergence of forward market prices from spot prices, so the agreed-upon methodology didn't address a major and expanding risk we face today. Up to that point in time (2020), the projected annual value of our natural gas plants to NPE had varied around $30 million, with some years closer to $15 million and two modestly above $50 million.[22] No one in the

[21] Wilson, JDW-1TCR at 8:6-8.

[22] The 2010-21 average estimated forward market value, as demonstrated in Kalich's confidential workpaper "Confidential 2020 to 2023 Forward and Actual Price Operations Forecasts for Thermals New v12-7 (thru Oct 2023).xlsx." On the tab labeled "Gas MTM Summary", cells D7-D18, is $27 million, with a maximum annual value of $61 million and a minimum annual value of $14 million.

workshop anticipated the risks associated with forward markets projecting natural gas plant values exceeding $300 million a year, <u>a value nearly three times the totality of current authorized NPE.</u> It is plausible that a forecast error adjustment would be unnecessary if the Company was only managing a 10% share of $30 million through the ERM and its deadbands. But managing a 10% share of more than $300 million simply is not tenable. Accordingly, some level of forecast error adjustment for the relative magnitude of the issue is essential and reflects a better estimation of NPE.

Q. What will the impact be if the Commission does not provide a forecast error adjustment?

A. Absent recognition of forecast error, in today's market, and under the current ERM, the Company almost certainly will continue to absorb unaccounted for additional normalized costs through the ERM during the pro forma period, as we must accept the first $4 million where costs exceed NPE with no sharing with customers. We then must accept half of the next $6 million and 10% of any additional costs over $10 million. In each of the past reported years, 2021-2023, NPE has exceeded the $10 million level of both deadbands. Accordingly, without an adjustment, the impact on the Company could easily exceed $7 million.

One should expect costs to be higher or lower each year as market conditions change and values shift from the median projection. It is essential then that customers get lower rates in the cases where NPE is low relative to the forecast, and the Company has protection where NPE is high relative to the forecast. It is not apparent that the parties understood from the Company's original testimony that the forecast error adjustment could be <u>either</u> a positive (increases NPE) or negative (lowers NPE) value. Presently, market conditions highlight the need for a forecast error adder, but in past filings with NPE falling due to decreasing natural gas prices, the forecast error adjustment almost certainly would have been a negative adjustment lowering customer base rates. It works both ways.

Q. Do you agree with Witness Wilson claims that the forecast error difference is not an expense?[23]

A. No. Forecast error is, by definition, a cost, as it is driven by the differences between authorized and actual expenses. As explained above, forecast error <u>can be an increase or a reduction</u> to NPE depending on market conditions. Forecast error better reflects trends in NPE and makes the ERM fairer by ensuring there is not a continued bias by which one party or the other inevitably begins in a negative ERM position. Absent a forecast error adder in this case, Avista is destined to have NPE greatly above what is forecast and will therefore be inevitably forced to cover the deadbands and 10% of the remaining costs. This is not equitable or what was intended by the sharing mechanism. It is not reasonable that the only means to recover all legitimately incurred costs occurs <u>in the rare case</u> where the portfolio experiences significantly better than median conditions, such as a high-water year with sustained high market prices, and those factors are not in the Company's control.

Q. Witness Wilson, explains that forecast error in certain years is positive and in other years negative, but that Avista in a data response highlights a new risk beyond our control that causes chronic under-collection of costs.[24] In this data response, was the Company suggesting that forecast error will be a cost to customers over time?

[23] Wilson, Exh. JDW-1TCR at 8:10.
[24] Wilson, Exh. JDW-1TCR at 8:17 to 9:8.

A. No. He is referring to Avista's response to DR 192 (Exh. CGK-14) where it highlighted the impact of collapsing (from the time of rate setting to when costs are actually incurred) value of our thermal assets, and that forecast error can be both positive and negative. The positive forecast error presented in this case reflects conditions present in today's wholesale markets. Forecast error calculated in previous periods, such as during the long downward slide of natural gas prices between 2009 and 2020, would be a forecast error adjustment resulting in lower NPEs. The forecast error is proposed to reflect market conditions not otherwise modeled in Aurora based on market trends. Only with such a forecast error adjustment, or some similar mechanism, can an ERM operate fairly with equal opportunities for the ERM to have a net positive or negative effect. In short, for the ERM to operate fairly and as intended, where the NPE base does not reflect all significant costs and benefits, including ones that Aurora cannot effectively model, one party (evidence in this case indicates the loser will be the Company) is destined, in all but the most favorable conditions, to absorb much or all the costs not modeled in Aurora.

Q. Do you agree with Witness Wilson's statement that including the forecast error adjustment would be unprecedented?[25]

A. I do not view recovering known and measurable costs as unprecedented. We pro form many assumptions to estimate future costs. Forecast error is simply one additional factor to address aspects that were not recognized in the past but that were less significant. With a $30 million annual gas fleet contribution to reducing NPE, a 10% variance previously may have been acceptable. Today, with the fleet's value approximating $300 million annually,

[25] Wilson, Exh. JDW-1TCR at 9:12-14.

a 10% variation simply cannot be ignored. Analysis and testimony provided in the case shows that deltas can greatly exceed 10%.[26]

Q. Witness Wilson identifies drivers of NPE variability in his testimony.[27] Does he cover the primary drivers of NPE variability in your view?

A. While a good start, it is important to highlight that it is not simply power and natural gas price volatility presenting risk to the Company. I will detail in later testimony that the current trend of forward market IMHR collapsing between the time of ratemaking and actual operations has created a large new risk to our business that must be quantified as a large part of the forecast error.

Q. Do you agree with Witness Wilson's categorization of risk being outside or within Avista's control?

A. Table 1 of Witness Wilson's revised testimony[28] illustrates the large number of risks Avista faces in its business as they relate to NPE. His short-term versus long-term categories are helpful. Yet categorizing them as he has done, into outside and inside Company control, is misleading and some aspects are incorrectly categorized or should at least be broken into sub-components of controllable or uncontrollable. I do not agree with Witness Wilson's summary assessment of his revised direct testimony where he states, "For the most part, I believe that the classifications in Table 1 are fairly straightforward and illustrate the division of responsibility."[29] While the items identified are a list of most risks we face (the relationship between natural gas and electricity prices of recent times means this item should be added to

[26] See Kalich workpaper "Confidential 2020 to 2023 Forward and Actual Price Operations Forecasts for Thermals New v12-7 (thru Oct 2023).xlsx".
[27] Wilson, JDW-1TCR at 9:18.
[28] Wilson, JDW-1TCR at 11:1.
[29] Wilson, JDW-1TCR at 11:6.

the outside of control list), overall, most items placed in all categories by Witness Wilson are outside of utility control. Looking back in time, we have significantly less control now than in the past when forward, spot, and bilateral markets were more liquid, electricity prices generally were lower, the IMHR in the forward markets more closely resembled IMHR in the spot market, and forward market premiums generally were more muted.

Q. Do you agree with the drivers listed in Witness Wilson's testimony as "within Avista's control subject to short-term variation"?[30]

A. Not all of them. In the past there was more utility control in these areas, but not today. I will address each specifically.

Q. Do you agree that plant operating practices are substantially within utility control?

A. Yes. Of the items included as "within utility control", plant operating practices have the largest component of being within utility control.

Q. Do you agree that O&M costs are "within utility control"?

A. Generally, yes, but many Operations and Maintenance (O&M) cost drivers are not completely within utility control. Among other items, O&M cost variation is driven by facility age, contractor costs, and materials costs. The Company does not control the physical depreciation that naturally occurs on its facilities, even when appropriate regular and preventive maintenance is performed as our various hydro and thermal maintenance programs are designed to do. All Company-owned facilities in our portfolio are decades old; that some are over 100 years old and are still operating is a testament to the time and effort we put into maintaining facilities. O&M costs for plants well into or beyond their design life are subject

[30] Wilson, Exh. JDW-1TCR at 11:1.

to additional cost risks that the Company has limited ability to affect. Recent years have Witnessed large levels of inflation in material and contractor costs, both affecting our O&M costs. Finally, O&M costs in our case, for the most part, are based on a single test year, meaning there is not an historical trend or average used that would smooth out aberrations or recognize cost trends generally.[31]

Q. Do you agree that hedging costs are within utility control?

A. No. Overall, actual hedging is <u>not</u> within utility control. We have a hedging plan containing direction and preferences, but <u>our ability to hedge is driven by market conditions dictating our actions</u>. As explained in the Company's direct case, and in this rebuttal, <u>liquidity</u> in the marketplace is so greatly reduced and price premiums are so high, that <u>much of the historical hedging we've done either cannot be executed at all or cannot be done with any level of affordability</u>.[32] As such, this hedging "level" is not at our disposal. Second, while the small number of hedges we manage to execute prior to the rate filing do affect NPE, there is no guarantee, and in fact it can be unlikely, that significant levels of hedging will be available, due to liquidity or disadvantageous pricing, to protect against most of the NPE risks facing the Company. Hedging is oftentimes misrepresented by parties as a "cure-all" to protect against NPE cost variance. In practice, hedging has a very limited contribution. While Witness Wilson implies hedging can lessen NPE variability, he acknowledges the Company's position by stating "there is evidence that Avista's hedging for

[31] Colstrip relies on a separate tariff and major maintenance at Coyote Springs 2 is capitalized rather than expensed.

[32] The Company does not believe that placing hedges at prices significantly higher than expected spot market levels is in the customer interest. Our risk management and hedging plans prevent such activity when prices are not favorable for customers. The Commission generally has not supported recovering option premiums from customers, essentially removing this option from consideration. Witness Wilson (JDW-1TCR at p. 12, ln. 11-12), on behalf of Staff, specifically states in testimony that he does "not wish to suggest that Avista should include hedging costs and benefits in its forecast of NPE."

physical power has decreased over the past five years."[33] Exh. CGK-15, a data response to Public Counsel, illustrates this decrease clearly, with <u>no</u> electric power forward purchases having occurred since 2021.

Q. Why has hedging decreased?

A. Hedging has decreased for various reasons. Some are that we are unable to find counterparties for the electricity transactions we need to hedge the value of our portfolio, and specifically our thermal fleet. Premiums in the marketplace for these forward contracts are high, meaning we cannot transact under favorable terms even when forward market prices show an opportunity. With increased market volatility, taking a position in the market with a forward contract subjects the Company, and any other party in the market, to very high margin calls relative to history. Finally, with tightening requirements for reliability, such as WRAP, and falling regional capacity surplus, parties appear less interested and/or able to transact in the forward markets.

Q. How do collateral and margin calls come into play with hedging?

A. In rising and/or volatile markets, collateral costs associated with buying and selling electricity and natural gas increase greatly. When forward markets are elevated relative to where they clear in the spot market, there is a natural bias toward large collateral calls as we approach real time, and the value of the electricity or natural gas falls relative to its purchase price. Illustration No. 2 shows the rising cost of our hedging programs.

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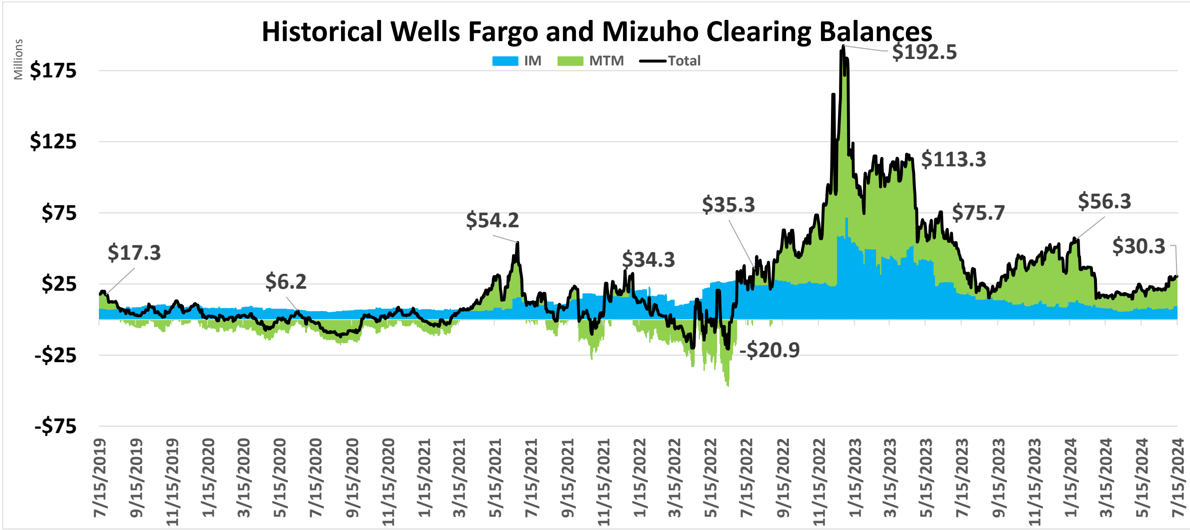
[33] Wilson, JDW-1TCR at 13:17.

<u>Illustration No. 2: Wells Fargo and Mizuho Clearing Balances July 2015 – July 2024</u>



There have been several significant market events over the past three years that have caused extreme spikes in power and natural gas prices. The price volatility in power and natural gas is also much greater as the market has changed. It is not uncommon for Avista to experience collateral calls of over $3 million per day now, and that was a rare occurrence several years ago. The rising cost of collateral is an unfortunate reflection of today's markets relative to those we experienced just a few years ago.

Q. Witness Wilson states that the Company is not minimizing cost variability by including CCA allowance cost hedging.[34] Does this argument support his contention that forecast error be removed from NPE?

A. No. Avista is not including CCA costs in this case; it therefore is not appropriate to include CCA hedging in forecast error calculations. Further, the CCA marketplace is still immature, meaning there are many risks and unknowns associated with modeling hedging for CCA allowances.

[34] Wilson, JDW-1TCR at 12:6.

Q. Do you agree that fuel procurement practices are within utility control?

A. While the practices themselves are within utility control, the market dictates whether our practices are effective in making NPE more predictable. Like hedging, we are at the whims of the marketplace to identify opportunities to benefit NPE, and those opportunities are much less than in the past. Much fuel procurement (i.e., natural gas) is directly tied to our ability to transact in the electricity marketplace to either sell off surplus generation made possible by a fuel purchase or the ability to sell natural gas to un-fuel resources when forward electricity prices are lower than the cost of running our generation facilities. But where the liquidity to transact on the electric side doesn't materialize, or the price premiums for electricity are very high, fuel procurement practices offer very limited benefits to NPE.

Q. Do you agree that bilateral transactions outside the EIM are within utility control?

A. It is true we make choices to transact when bilateral opportunities arise, but again we are a <u>price taker</u>. If favorable market conditions do not materialize, we cannot take advantage of bilateral opportunities. This subjects our NPE to significant variation day-to-day, month-to-month, and year-to-year, depending on conditions in the marketplace. With so many parties joining EIM, our opportunities in the residual bilateral market trade have been reduced and we cannot rely on them as much as we have in the past.

Q. Do you have any observations you'd like to make about the bilateral markets while we are on this topic?

A. Yes. Staff, Public Counsel, and AWEC Witnesses all argue the Company estimate of EIM value is too low. Public Counsel goes so far as to argue that CAISO's benefit calculation approximating $20 million annually is more appropriate for ratemaking. These arguments are incorrect. EIM does value the short-term flexibility of our plants. Yet prior to EIM, we obtained most of the $20 million CAISO-calculated "counter factual" value through the bilateral markets we participate less actively in today due to fewer participants being in that marketplace. So much or most of the EIM value identified by CAISO's reported benefit analysis is in fact value we already were including in NPE in previous cases and modeled in hourly Aurora runs. Only the *incremental* value of EIM should be included as an offset to NPE. In following the Commission-approved Puget Sound Energy (PSE) EIM valuation methodology in Aurora, the delta between the hourly and 5-minute Aurora modeling runs, we are correctly estimating the incremental value of EIM. $20 million is a gross over-estimation.

Q. Do you have another observation supporting your position that the EIM reported benefit overstates incremental EIM benefits?

A. Yes. PSE's modeling of EIM benefits showed approximately $15 million in incremental benefits that were approved by the Commission in its last rate case on nearly $1 billion in NPE.

Q. Do you agree with Witness Wilson's testimony where he states the Company is in an enviable position as a net seller because NPE can be lower in some market conditions and implies that this position undercuts the Company's forecast error adjustment?[35]

A. No. Being long on natural gas-fired generation in today's marketplace lowers NPE greatly relative to where we would be if we didn't have the surplus. The present case builds in about $400 million in thermal plant value ($300 million for our natural gas plants alone) for customers. In the past, the value of the same generation fleet was well under $100

[35] Wilson, Exh. JDW-1TCR at 14:1.

million ($30 million for our natural gas plants alone) and more indicative of what we experience in operations. So NPE is lower, but the outcome is large customer and Company exposure to cost variability. Recent years demonstrate the risk in valuing natural gas generation at forward market prices when actual value is defined by actions the Company can take in the short-term markets. It simply is not equitable to build into this rate filing lower NPE based on optimistic thermal plant surplus sales when our NPE costs are otherwise rising across the board. Absent a forecast error adjustment, the Company is "set up" to absorb millions in the ERM since the baseline is skewed against us. Even with the Company absorbing much of the cost, customers still will face rising costs as their share of ERM charges becomes significant and require rate adjustments.

Q. How does the IMHR "spark spread" affect your business today relative to the past?

A. Given our long position and natural gas-fired generation ownership, we are especially sensitive to the relationship between natural gas and electricity prices, or the "IMHR", or "Implied Market Heat Rate." The concept of IMHR is related to what some refer to as the "spark spread," an operating-margin-per-MWh driven by specific operating characteristics of a plant. Calculated IMHR offers a means to compare against any natural gas plant, and its calculation simply divides the electricity price by the natural gas price. For example, if the electricity price is $50/MWh and the natural gas price is $5/dth, then the IMHR is 10. To determine the spark spread on a 7 dth/MWh (its heat rate) combined-cycle combustion turbine plant using an IMHR, subtract its heat rate from the IMHR and multiply by the natural gas price. In this case, with an IMHR of 10 and a heat rate of 7, the spark spread is $15/MWh).[36]

Q. Why is the IMHR you reference here material in this case?

A. Because unlike in the past, we have Witnessed IMHR premiums in the markets not being sustained in the spot market. With NPE estimates based on forward market conditions and the resultant forward IMHR, and with spot market conditions and IMHR so drastically different, much of the forecast value that reduces NPE cannot be realized.

For example, September 2021 forwards equated to an IMHR of 13.22 for calendar year 2022. Yet 2022 spot prices ended up at 9.66. This IMHR delta of 3.56, or 37% overstatement, equates to approximately $30/MWh or $30 million on one million MWh. Avista's thermal fleet generates many millions of MWh annually.

Q. If a forecast error adjustment is not allowed by the Commission, what will be the result?

A. Absent a forecast error adjustment, rates will be based on forward prices that don't reflect market conditions when we actually incur costs. NPE will be grossly understated, meaning there will be an unfair transfer of value from the Company to customers through the ERM through no fault of its own and for reasons beyond its control. In the case where NPE is under-forecast, the ERM becomes punitive to the Company. We absorb the first $4 million of under-forecast costs, and $7 of the first $10 million, plus 10% of any remaining under-forecast.

[36] (10 IMHR – 7 dth/MWh heat rate) * $5/dth = $15/MWh. Note the spark spread would be reduced by variable operating costs which are excluded here to simply the example.

Q. Will recognizing forecast error increase the forecasting accuracy of NPE, or otherwise make results fairer?

A. Yes. Even if the forecast error adjustment doesn't make the average forecast more precise, as the Company believes it will, it still makes the recovery of costs over time fairer to customers and the Company. This is because any biases in the data will have the result of being self-correcting. In other words, if there is an overcollection in a rate year, the forecast error calculated for the next rate filings will necessarily shift the forecast error in a direction to reduce NPE.

Q. After reviewing testimony, does there remain an over-arching reason forecast error should be included in base rates?

A. Yes. The parties objecting to the forecast error adjustment universally state that it is not a power supply cost, and any variation in Net Power Supply Expense (NPE) should flow through the Energy Recovery Mechanism (ERM). Yet forecast error is every bit as real and valid as inputs reflecting forecasted loads and fuel prices. Absent a forecast error adjustment, base rates are not set appropriately, meaning a bias against one party or the other occurs. Public Counsel Witness Earle, in his Figure 1,[37] illustrates this clearly. Due to various circumstances, fundamentally driven by a rise in natural gas prices, Avista absorbed over $100 million over the 2003-08 period through the deadbands and 90/10 sharing. During the 2011-20 period, customers absorbed about $100 million through those same deadbands and 90/10 sharing. This over-recovery was driven greatly by gas prices generally falling over the same period. Since 2020 Avista has absorbed about another $80 million of under-forecasted cost, even as natural gas prices have continued to fall. In this case, the Company has demonstrated

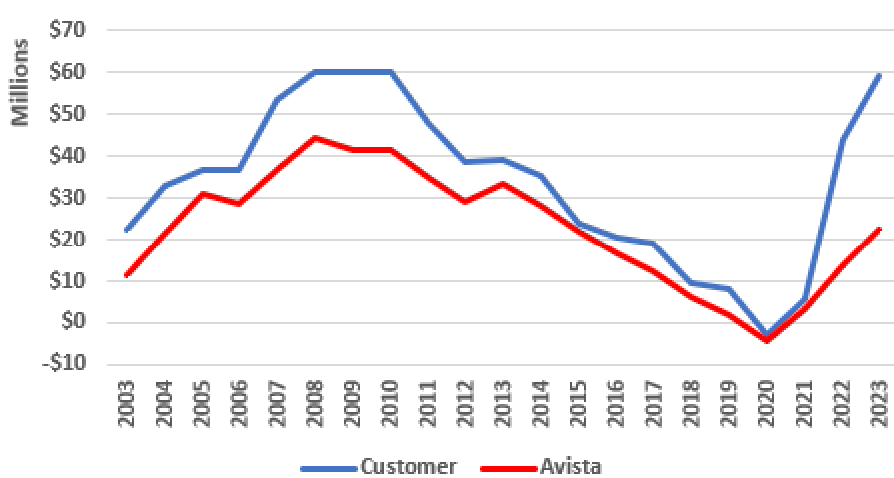
[37] Earlier, Exh. RLE-1CT at 6:5.

that without a forecast error adjustment, the Company almost certainly will continue to be on the losing end of the ERM. The Company should not be punished by the disallowance of costs beyond its control.

Q. Does the existing ERM, with its current deadbands, shift too much risk to Avista?

A. Yes. Much of the concern with achieving a correct NPE by including forecast error is created by the structure of the ERM itself. While the ERM contains 90/10 sharing after the Company has absorbed the first $4 million of forecast error and 50% of the next $6 million of forecast error, the results show that the Company in totality absorbs a large share of forecast error, greatly above 10%. Over the ERM life, Avista has carried just over 40% of the forecast error while customers have carried the balance, meaning the deadbands shift significant costs to Avista. This is a large burden for a company of Avista's size; the $23 million average equates to about 15% of Company average annual 2021-23 net income. Please see Illustration No. 3 for the cumulative cost share of the ERM.

<u>Illustration No. 3: ERM Cumulative Cost Share</u>



Q. Is Avista responsible for the error in its forecasts as suggested by Staff, Public Counsel and AWEC?

A. No. As explained in Company testimony, the forecast errors are due to the many unknowns in the marketplace – unknowns that are of much greater magnitude than the operational modifications we can make to keep plants available and optimize hydro operations and market transactions. From a statistical perspective, the Company is being asked to perfectly forecast NPE when <u>it does not, and cannot know</u>, with significant certainty all the factors driving key assumptions and their effects in the forecast. These include overall market price levels of natural gas and electricity, the IMHR driving value of surplus thermal plant sales, and hydro conditions.

Q. If Avista is not responsible for the forecast error, is it reasonable to include an estimate of such error in the NPE in base rates?

A. Absolutely. Forecast error can be reflected and input into the pro forma. Present market trends indicate that forecast error would increase pro forma rates. Historically the trend would go both ways, as there are significant periods of under- and over-estimation. You can see the trend in the ERM Cumulative Cost Share in Illustration No. 3 above. Rising ERM balances, Witnessed during the periods 2003-08 and 2020-23, means the forecast error adjustment would be positive and increase NPE to reflect then-current market conditions. Falling ERM balances, from approximately 2009 to 2020 would indicate negative forecast error adjustments that lower NPE.

Q. Are you saying that unlike in the testimony of Staff and other intervening parties, <u>forecast error is not additive to NPE but a facet of it</u>?

A. Yes. That is precisely the point. This is not a one-way adjustment. Over the past few years, we have come to an understanding that certain market drivers outside Company control are responsible for much of the forecast error. In some periods, like when natural gas prices were generally falling between 2003 and 2008, the current NPE forecast method (and previous methods) over-state costs. But in other periods, such as today when the IMHR[38] is much above its long-run average, the NPE method grossly understates NPE.

Q. Based on a review of all testimony in this proceeding, is the Company able to support a forecast error adjustment smaller than the $65.8 million filed in its case?

A. Yes. Given the complexities associated with estimating NPE, the Company can agree to $29.7 million, the 2021-23 average of the delta between authorized and actual NPE. See Table No. 3.

Table No. 3: 2021-23 Average of Authorized vs. Actual Power Supply Expense

Year	Tracked Power Supply Costs		
	Actual	Auth.	Delta
2021	112.3	96.0	16.4
2022	121.1	72.3	48.8
2023	131.8	107.8	23.9
Average			**29.7**

This three-year average value is much lower than our original request and is based on an historical timeframe where markets clearly have shifted to a new paradigm.

Q. How does this answer concerns expressed by the parties?

[38] IMHR defines the operating margin of a thermal plant using natural gas. It is calculated as the electricity price divided by the natural gas price. An IMHR of 10 applies to market conditions where electricity is $50/MWh and the natural gas price is $5/dth, or where electricity is $25/MWh and the gas price is $2.50/dth, and so on. If the IMHR increases, the value of a plant goes up. For example, a 7 dth/MWh heat rate gas plant will generate revenue above fuel costs at a rate of $15/MWh if gas prices are $5/dth and the IMHR is 10 (implying an electricity price of $50/MWh). If the IMHR rises to 15 caused by electricity prices rising from $50/MWh to $75/MWh in this example, with similar gas prices, plant operating margins increases to $40/MWh, a near tripling of value.

A. Mr. Kinney explains in his rebuttal testimony how this modified proposal addresses the concerns of Public Counsel Witness Earle and AWEC Witness Mullins, as well as concerns of the Commission in Order 07 of this docket denying Staff's motion for partial summary determination on rejecting the Company's proposal to include forecast error in NPE.

Q. Besides claims made by Witness Wilson that forecast error is not an actual cost, Staff appears to base its rejection of forecast error in the case on it not being known and measurable. Do you have any further comment?

A. The forecast error adjustment proposed by the Company is neither less nor more known and measurable than other adjustments and assumptions made in support of defining NPE–something which is done in every rate case over the past decades. There are many examples to consider. Hydro assumptions in the pro forma are based on at least two large assumptions that will not occur in the rate year: (1) generation is assumed based on median water and its (2) contribution to peak-hour loads is based on a five-year average of historical generation shape. Wholesale electricity and natural gas market prices are based on 3 months of forward market prices that are demonstrated to not always be accurate in predicting conditions in the rate year. Power plant operating performance is based on a 5-year average of historical operations, conditions that are unlikely to be perfectly accurate. In prior cases, the NPE is pro formed into rates. Transportation contracts, broker fees and other costs also are based on 5 years because the specific quantities expected in the rate year are not known with precision. Loads are based on the test year with weather-normalization assumptions that surely will not equal the actual demands served in the rate year. None of these many elements can be "known and measurable" with precision and yet they are used by the Commission in arriving at a pro forma NPE, time and time again in making the best attempt at arriving at a power supply pro forma adjustment. The Commission has long understood the need to arrive at some estimate of power supply costs in the rate year, irrespective of how imperfect it may be, and even though not perfectly "know and measurable." It cannot do business in any other way when attempting to arrive at just and reasonable rates, in a way that matches revenues and expenses.

These examples demonstrate the many assumptions necessary to arrive at NPE. The concept of forecast error, which essentially accounts for the errors in these assumptions, again is neither more nor less known. Rather, it is part and parcel of the NPE. Further, both the power supply modeling methodology and past Commission approvals of prior requests based on these assumptions driving NPE, demonstrate reasonable assumptions and projections are necessary. It is, therefore, not appropriate to subject forecast error to a standard greater than the other assumptions driving NPE, of which it is a part.

Q. What guidance has the Commission provided with regards to Pro Forma Power Supply Costs being "known and measurable" versus forecasted?

A. The Commission has provided consistent guidance in several prior Avista general rate case proceedings. In Avista's 2010 GRC, Docket UE-0100467, et.al., the Commission's Order 07 noted:

> In a rate case, Avista's power costs are fully forecasted. To provide the most accurate cost forecast at the time of setting rates, companies have incorporated the most current energy pricing information into their forecasts. We do this to ensure that rates are set using the most accurate projection of future market conditions. We believe that ratepayers and the Company are best served by this practice, and this case is no exception.[39] (emphasis added)

[39] Order 07, Docket UE-100467, et. al., at page 8, paragraph 21.

More recently the Commission reiterated this guidance within its January 31, 2020 "Policy Statement on Property That Becomes Used and Useful After Rate Effective Date" ("Policy Statement")[40]:

> The actual amount of the change must be also be "measurable." This has historically meant that the amount cannot be an estimate, projection, product of a budget forecast, or some similar exercise of informed judgment concerning future revenue, expense, or rate base. The Commission previously has made exceptions, such as when it considered the use of attrition adjustments and power cost modeling forecasts when determining whether rates are just, reasonable, and sufficient, pursuant to RCW 80.28.020.[41] (emphasis added)

Q. Is Staff then correct that forecast error is not known and measurable and should be rejected?

A. No. Forecast error is neither less nor more known than the many other assumptions already making up our NPE value. It should be included in our NPE used in setting base rates. In its Order denying Staff's Motion, the Commission expressed concern that the forecast error adjustment would not pass muster under the "known and measurable" standard.[42] If that were true, then the NPE pro forma adjustments used in prior rate cases would also fail the "known and measurable" test, as discussed above.

[40] Docket U-190531

[41](footnote included in the text) Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils., Docket Nos. UE-090134 & UG-090135, Order 10, 21 ¶ 49 (Dec. 22, 2009) (hereinafter "Order 10") (power cost modeling); Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils., Docket Nos. UE-120436 & UG-120437 (consolidated), and UE-110876 & UG-110877 (consolidated), Order 09/14, 26-28 ¶¶ 70-73 (Dec. 26, 2012) (attrition adjustment).

[42] Order 07, Docket UE-240006 et. al., pages 29, par. 82 "Staff argues that in order for portfolio error adjustment to be applied pro forma to the revenue requirement, the Company must show that that the adjustment is: (1) known, (2) measurable, and (3) not offset by other factors.

V. ENERGY IMBALANCE MARKET (EIM) BENEFITS

Q. Witness Earle states that Avista should not use EIM, EDAM or Markets+ as "an excuse for Avista giving up control on costs."[43] Has the Company "given up" on controlling costs because of EIM, EDAM or Markets+?

A. No, citing these significant and welcome market developments does not mean we give up on cost control. It simply means the impact of these changes on our business must be considered. Avista is not a participant in EDAM or Markets+, yet participation by our trading partners in these markets will affect our business. EIM already demonstrates how market changes can detrimentally affect other markets; we lost significant liquidity in the hourly bilateral markets as EIM expanded its footprint among northwest utilities and trading partners. We should expect similar or greater impacts once larger trading volumes in EDAM and Markets+ begin, meaning that our most-important day-ahead trading opportunities could suffer similar or greater losses in liquidity and have impacts on our net costs of supplying customer load. Yet no matter the conditions we face, the Company will always strive to control costs; lower costs are good for our customers and are good for our business.

Q. Witness Earle finds it "curious" that EIM has not offered an opportunity for the elimination of personnel and goes so far as to imply we should eliminate our day-ahead and real-time trading desks.[44] Should participation in EIM, EDAM and/or Markets+ lead to staffing reductions?

A. No, of course not. This curious statement shows Witness Earle's lack of real world experience. It is well understood that these markets offer new value relying on more,

[43] Earle, Exh. RLE-1T at 15:4.
[44] Earle, RLE-1CT, at 15:20 to 16:6.

not fewer, staff. A new market doesn't magically mean that staffing requirements go away and that somehow the new market handles everything. Instead, these markets bring with them new complexities requiring more staffing with employees having higher skill levels than was needed before. The existing markets continue as well and must also be managed at the same time.

The Company knows these facts first-hand based on EIM experience. The Commission notes this in its recent PacifiCorp Order with Staff Witness Wilson agreeing "that participation in organized markets will require the same, if not more, expertise, planning…"[45] These complex markets, while bringing net financial benefits to customers, do require large investments in people and systems, and additional investments in new staff and technologies. This is Avista's experience.

Q. What are the various financial benefits realized by the Company through EIM?

A. EIM revenues fall into the two primary categories: Dispatch and Transfer. Because of CCA compliance requirements, the Company no longer can sell into California to extract gains from greenhouse gas (GHG) revenues in EIM.[46] We also receive no material revenues from Flex Ramp.[47] Therefore, the only value components applicable to the Company's NPE are net Dispatch and Transfer revenues. By net, I mean the EIM both charges and credits the Company within each category depending on whether we are buying (charges) or selling (credits) power, plus additional congestion and miscellaneous fees that can result in charges or credits.

[45] Docket UE-230172 Order 08 at 358.
[46] Avista ceased GHG trading at the end of 2022.
[47] Flex Ramp is a service matching variability from gross load, wind and solar forecasting errors.

Q. What are the historical totals for net Dispatch and Transfer revenues?

A. CAISO calculates these revenues as part of its "counter factual," analysis. Totals for these two categories are shown below in Table No. 4. Annualized, the value is $20.2 million over the Company's EIM history from March 2022 – March of 2024.

<u>Table No. 4: Monthly EIM History March 2022 to March 2024</u>

Mo	Disp	X-Fer	Sum	Mo	Disp	X-Fer	Sum	Mo	Disp	X-Fer	Sum
Mar-22	(0.1)	1.3	1.2	Dec-22	12.2	(7.3)	4.9	Sep-23	2.8	(1.1)	1.7
Apr-22	1.7	(0.3)	1.3	Jan-23	2.3	0.1	2.4	Oct-23	3.8	(1.4)	2.4
May-22	0.7	0.6	1.3	Feb-23	1.1	0.3	1.4	Nov-23	2.0	(0.9)	1.1
Jun-22	(0.0)	1.2	1.2	Mar-23	0.7	0.9	1.5	Dec-23	1.4	(0.7)	0.7
Jul-22	1.6	(1.1)	0.6	Apr-23	3.6	(1.4)	2.2	Jan-24	9.7	(3.5)	6.2
Aug-22	3.6	(1.7)	1.9	May-23	0.3	1.3	1.6	Feb-24	1.0	(0.3)	0.7
Sep-22	3.9	(0.7)	3.2	Jun-23	1.7	(0.6)	1.1	Mar-24	0.6	(0.1)	0.6
Oct-22	0.4	0.6	1.0	Jul-23	1.6	0.0	1.7	Apr-24	-	-	-
Nov-22	0.7	1.0	1.7	Aug-23	2.0	(0.3)	1.7	May-24	-	-	-
										Average	1.7
										Annualized	20.2

Q. Should the Commission adopt this annualized value as a reduction to NPE, as recommended by Witness Earle?

A. No, by following PSE's Aurora modeling method using 5-minute dispatch, EIM values <u>already</u> are reflected in the Aurora results. Furthermore, and as described below, much or most of the CAISO-calculated counter-factual value comes at the expense of lost opportunities in the hourly bilateral markets. In other words, were we to return to a pre-EIM market, much or most of the same value would be captured through greater hourly bilateral trading volumes.

Q. How is the modeling approach reflecting EIM values different from past rate case filings?

A. In previous cases we modeled hourly markets in Aurora, emulating revenues we received in the hourly spot market. In our last filing, when we had just joined the EIM and had limited experience in the market at that point, we accounted for incremental EIM benefits using an assessment performed by the consultant E3.[48] Following the methodology used in PSE's last approved case where it included EIM in its power supply modeling,[49] we hired an experienced consulting firm, Borismetrics, to develop intra-hour (i.e., 5-minute) data for variable energy resources and EIM prices. Avista then weather-normalized 5-minute test period loads. These efforts gained the data necessary to represent a 5-minute dispatch within Aurora, enabling us to use the new PSE approach and add it to power supply modeling.

We then ran Aurora in two steps. Step One was an hourly dispatch against hourly market prices and loads to emulate the hourly marketplace that exists today. The hourly market transactions and unit commitments from Step One were input into Step Two, a 5-minute Aurora dispatch run, as market purchase and sale obligations, just as we've always done with term forward market purchases and sales. These hour-ahead transactions were valued at hourly prices in Step One. Step Two included re-dispatch of resources to achieve additional value from 5-minute dispatches based on the commitment from Step One. Prior to this filing, we ran only Step One. No further optimization occurred.

Q. After reviewing testimony in this case, does the Company still believe the incremental value for EIM is $5.5 million?

A. No. The incremental value is $6.6 million, not $5.5 million. The method used to arrive at the earlier estimate was in error. After review of the parties' testimony, and after

[48] E3 is a consulting firm Avista hired to assess the potential benefits of joining the EIM. See https://www.ethree.com for additional details about this firm.
[49] Docket No. UE-200980.

further discussion with PSE, we learned that the approach described above correctly values all dispatch in EIM, and after that our method to identify the incremental value for EIM by limiting Aurora in the hourly market was incorrect. Our updated Rebuttal case, based on the changes described herein, therefore correctly values EIM benefits at $6.6 million (versus $5.5 million).

Q. Should an adjustment be made to reflect CAISO's counter-factual estimate of EIM, as is the recommendation of Witness Earle, and reduce NPE by over $20 million?[50]

A. No. We followed the PSE approach to modeling EIM in Aurora. As such we capture expected NPE within a 5-minute market. Any further analysis is simply to estimate the EIM share of NPE. Unlike our last case where, due to a lack of intra-hour data and EIM experience, we had to add an incremental benefit for EIM, in this case we have explicitly modeled an EIM future by running at 5-minute intervals. No further adjustment is necessary or appropriate.

Q. Can you provide an example where a CAISO calculation would overstate EIM benefit for the Company?

A. Yes. Assume a market with real-time hourly prices of $30/MWh in the middle of the day when Westcoast loads are moderate. The Company bids 100 MWh at a price of $50 to recognize that generating with hydro in the middle of the day would leave us with less generation available over the evening peaks when we otherwise would use the hydro energy to serve load and prices are $50/MWh. The CAISO market clears at $25/MWh and replaces our generation at that price. CAISO's counter-factual, in this example, would calculate a

[50] Earle, Exh. RLE-1CT at 33:7-9.

savings to Avista of $25/MWh ($50/MWh bid minus $25/MWh CAISO price) on the 100 MWh, or $2,500 ($25/MWh * 100 MWh). Yet our actual value was the delta between the $30/MWh real-time price, not the $50/MWh bid price. Using the $30/MWh real-time price, our actual opportunity cost, and the CAISO price of $25/MWh, the real benefit for that period was $500 (100 MWh * [$30/MWh CAISO price minus $25/MWh real-time price]). The CAISO counter-factual for this hour would be overstating our benefit by $2,000.

Q. What about the NPE adjustments recommended by Witnesses Mullins and Wilson?

A. Witness Mullins recommended a reduction to NPE reflecting certain settlement charges reported by CAISO equating to $3.0 million.[51] Witness Wilson, in revised testimony, relies on CAISO "group codes" to arrive at an NPE reduction of $1.4 million.[52]

The Company has reviewed these adjustments and believes they should not be included in the NPE estimate. Of Witness Mullin's $3.0 million, $2.1 million was GHG revenue the Company no longer receives. We have not included GHG adders in our EIM market bids since 2022 because of CCA legislation, and therefore even were the Commission to adopt his work, the value should be reduced to $0.9 million.[53]

Witness Wilson relies on certain CAISO "cost groups" for his $1.4 million.[54] Review by our EIM Settlements Manager finds that cost codes are not appropriate to rely on for NPE as they are not granular enough to decipher which might or might not be already modeled in Aurora. Furthermore, in reviewing the specific cost codes, it became apparent that the majority

[51] Mullins, Exh. BGM-1T at 54:8-15.
[52] Wilson, Exh. JDW-1TCR at 18:17-22.
[53] Our 2022 monthly GHG benefit averaged $455,282 (Mar-Dec). There were some trivial GHG transactions in Q1 of 2023, averaging $269 in those months, but nothing thereafter.
[54] "Cost groups" are broader categories of individual EIM cost codes.

already are accounted for in the energy modeling of Aurora. After removing values already emulated in Aurora, the net was an increase to NPE of $0.3 million.[55]

Q. Based on this finding, are you recommending an increase to NPE based on EIM cost codes?

A. No, we are not recommending an increase to NPE based on EIM cost codes.

Q. Do you have concerns with Witness Earle's testimony on behalf of Public Counsel on the EIM issue?

A. Yes. Witness Earle's descriptions reflect a fundamental misunderstanding of how the Company models power supply costs, and how it calculates EIM benefits for this filing. His Curriculum Vitae (CV) does not contain any experience in actual utility operating practices and reflects no experience applicable to power supply modeling, such as running including industry standard models such as Aurora, Prosym, Promod, or Plexos.

Q. Do you agree with Witness Earle where he suggests that the Commission should order "…Avista to develop a valid EIM benefits forecast methodology"?[56]

A. Though the Company does not object, per se, to the Commission defining a specific methodology by order, the Company did follow the methodology used in PSE's recent case before the Commission.[57] Further, such a methodology would not be available in a timeline suitable for this filing.

Q. Witness Earle attacks the Company's reference to an E3 study used to preliminarily support joining EIM and setting EIM benefit levels in current authorized

[55] See workpaper "Adjusted 7-25-2024 WEIM calcs AWEC-DR-053 Att B_07.23.24.xlxs."
[56] Earle, RLE-1CT at 3:9
[57] Docket No. UE-200980.

rates.[58] Does this reference to an earlier E3 study support Witness Earle's contention that Avista's EIM benefit calculation in this proceeding is flawed?

A. No. The Company is unclear why Witness Earle attacked the E3 study reference or why he "inflation-adjusted" E3's earlier EIM benefit estimate.[59] The Company is not suggesting the E3 study justifies its latest calculations. Avista offered the E3 result only for the Commission and other parties who might be interested in a comparison of what the EIM benefit was in the last case.

Q. Witness Earle states that "Avista forecasts 5-minute EIM prices by first forecasting the average hourly EIM prices across five-minute intervals, and then from those average hourly prices forecasts the 5-minute prices."[60] Did the Company depart from the methodology and forecast hourly prices for this case?

A. No. Avista does not forecast prices. Prices are based on a 3-month average of forward prices, as defined in the Power Supply Methodology agreed to by all participants in the 2018-20 Post Supply Cost Modeling Workshop. The forward prices are shaped based on the test year.

Q. Is it reasonable to use an average of forward prices?

A. Yes. The 2018-20 Workshop guided decisions on standardizing approaches. There are competing complexities to balance; some might be expected to modestly benefit customers and some not. As an example, we shape prices hourly using the recorded Powerdex index for the test year, an average of reported market transactions from across the Northwest.

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[58] Earle, Exh. RLE-1CT at 29:9.
[59] While advocating for precision in EIM modeling methods generally, Witness Earle chose here to escalate the E3 study value specific to the power industry by the general Consumer Price Index when there are other indices specific to the power industry that could be used.
[60] Earle, Exh. RLE-1CT at 27:3.

Actual trades are not based on a single price; the Company in individual hours receives/pays counterparties varying prices for the power it sells and buys, even in the same hour. But Aurora requires a single price to perform its math. The single representation of one EIM market price for each 5-minute interval also is a simplification because we receive payments based on different locational-marginal prices at multiple locations.

Q. Are there additional reasons that the "averaging" Witness Earle concerns himself with is not material in this case?

A. Yes. Witness Earle's dispatch examples represent oversimplification of the dispatch problems faced by utilities. This shows again how modeling in Aurora does not reflect system conditions with precision. The example assumes plants are fully available to offer energy into the marketplace. It also assumes plants and units commit, de-commit, and ramp up and down with impunity with each 5-minute interval of time, and that operators and traders can execute perfectly based on perfect knowledge of what market prices will be. This absolutely is not the case. Resources cannot realistically shut down (decommit) at minute ten of an hour, and then restart (commit) at minute twenty to maximize profit, as the example would imply. Commitment and dispatch do not work in this way. Thermal resources cannot ramp that quickly across most of their operating ranges. Perfect execution is not possible. To help illustrate the flexibility of our plants relative to the assumption in the example, Table No. 5 offers key statistics as they relate to thermal plant commitment and dispatch. The table column "Ramp Energy As Share of Nameplate" shows that effective ramping in the 5-minute EIM periods is 5% of total plant capacity. Aurora modeling does not reflect these limits and therefore overstates flexibility.

Table No. 5:[61] Key Dispatch Characteristics of Avista's Thermal Fleet

Plant	Maximum Operating Capacity (MW)	Minimum Operating Capacity (MW)	Maximum Operating Range (MW)	Ramp Rate (MW/Min)	Maximum 5-Minute Ramp Energy (MW)	Ramp Energy As Share of Nameplate	Minimum Start-Up Time (minutes)
Coyote Springs Base Load Mode	307	140	167	10	25	8%	60
Coyote Springs 2-Duct Fire Mode	322	283	39	1	3	1%	60
Lancaster Base Load Mode	267	173	94	5	13	5%	60
Lancaster - Duct Fire Mode	293	231	62	1	3	1%	60
Rathdrum Units 1/2	150	102	48	6	15	10%	10
Boulder Park Units 1-6	25	25	0	0	0	0%	10
Colstrip Units 3/4	220	30	190	10	25	11%	168
Kettle Falls Biomass	50	8	42	2	5	10%	4
Kettle Falls CT	7	5	2	3	1	14%	10
Average	**1,067**	**684**	**383**	**23**	**51**	**5%**	**10**

Q. Are there other reasons why plants cannot offer capacity into the EIM market besides the physical limitations shared above?

A. Yes. Many units' operating ranges are restricted by ambient conditions (e.g., hot weather degrades combined cycle plant output by as much as 20% from its capability during cold winter periods), congestion, set asides for contingency reserves, regulation, flex capacity, and other ancillary services needed to support system operations.

Q. Is the Company able to achieve the values Witness Earle implies, even with capacity reduced greatly?

A. No. Witness Earle's example implies the Company can operate its system with perfect foresight and precision. The Monte Carlo method knows exactly what prices are going to do for each period of the analysis–something that is not possible. No Company has access to this complete and perfect level of data.

Q. Is it fair to benchmark the Company against analyses and models relying on perfect foresight?

A. Company traders do not have the luxury of perfect foresight. Assuming perfect

[61] Based on CCCT plants operating in duct fire mode.

execution on perfect price and perfect operational information simply is not possible. The lack of perfect foresight in prices and general system operations certainly degrades the amount of actual value achieved.

My workpapers help illustrate the fallacy of assuming "perfect trader execution."[62] They estimate that over the 2010-22 period the Company achieved 76% of the value possible with perfect foresight. Over the 5-year period ending in 2022, the value was 78%. See Table No. 6.

Table No. 6: Estimated Gas Fleet Value Achieved Relative to Perfect Foresight

2010	83%	2017	77%
2011	64%	2018	76%
2012	74%	2019	86%
2013	80%	2020	78%
2014	78%	2021	69%
2015	71%	2022	80%
2016	68%		
Average			74%
2018-22 Average			78%

Q. Do you find the ten million samples of Monte Carlo analysis described by Witness Earle compelling?[63]

A. No. Witness Earle runs ten million iterations of Monte Carlo analysis to find that perfect foresight dispatch without commitment or ramping limits with increased volatility leads to a higher average operating margin. This is simply an intuitive result not requiring such an analysis.

Q. Do you have concerns with the use of Monte Carlo analysis generally?

[62] See the table "Gas MTM Summary, columns F/ columns E, of the workpaper "Confidential 2020 to 2023 Forward and Actual Price Operations Forecasts for Thermals New v12-7 (thru Oct 2023).xlsb,"
[63] Earle, Exh. RLE-1CT at 24:3.

A. I have used Monte Carlo myself at various times over a 30 plus year utility career. The technology and its methodologies frequently mask deficiencies in both data available to, and user understanding of, the modeled problem. There are appropriate uses for Monte Carlo analysis, and Avista uses Monte Carlo in different areas of its business, including our Integrated Resource Plan. However, Monte Carlo analysis can often be misleading.

Witness Earle's Monte Carlo analysis does exactly this, by misleading the audience. His "findings" first demonstrate something very intuitive to the reader – namely, that more volatile prices afford a resource the opportunity to achieve higher operating margins. But then Witness Earle, knowingly or not, concludes that the Company can achieve higher values than modeled in Aurora. To effectively support such a conclusion, his Monte Carlo analysis would have needed to optimize data through Aurora. Finally, his work would need to recognize that no company can execute with perfect foresight and account for the demonstrated fact that Avista's fleet of thermal resources are not very flexible in 5-minute dispatch when compared to their nameplate ratings.

Witness Earle's modeling description is a classic textbook approach with simplifications that ignore key real-world issues, such as described above. An actual electric system has a series of engineering, regulatory, environmental, and practical trading restraints that must be accounted for. By not running the Monte Carlo analysis through Aurora, his misleading results are not constrained even by Aurora's generous dispatch logic assumptions. Absent, at minimum, including these dispatch logic constraints by running the analysis through Aurora, the Monte Carlo analysis, and Witness Earle's conclusions based on it, are not credible.

Q. Do you also have any concerns with Witness Earle's method of using

CAISO reported benefit data as a proxy for incremental EIM benefits?

A. Yes. First, though having access to the various streams of CAISO data, he failed to acknowledge that the Company no longer receives GHG revenues in EIM. That revenue stream dried up in late 2022 with Washington's CCA. The exclusion of no-longer existing GHG revenues artificially overstates our monthly average reported benefit value by $182,244 per month, or $2.2 million per year. Second, there are only 25 months of actual EIM data to evaluate. This is a very lean dataset given that operating and market conditions vary greatly from month to month and year to year. Basing results on data that he further reduced arbitrarily by choosing a 95th percentile confidence, reducing the dataset by another one-third.

A large driver of value in EIM is hydro. Since joining EIM Avista has seen monthly average hydro of only 87% of median. Calendar 2023 was 81% of median. Table No. 7 below provides more detail. Monthly values 95% of median or higher are highlighted in green. Below 85% they are red. Between 85% and 95% they are yellow. One should be cautious when using a short historical dataset, especially when conditions do not reflect median conditions.

Table No. 7: Avista Hydro Performance Since EIM Participation

Period	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Median	582	498	463	492	740	1,007	1,007	708	384	354	365	430	524
2022				662	697	952	982	825	390	308	339	410	452
2023	471	462	458	362	437	1,202	736	400	300	243	273	361	421
2024		446	439	496	562	714	821	478					
2022				135%	94%	95%	97%	116%	102%	87%	93%	95%	86%
2023	81%	93%	99%	74%	59%	119%	73%	57%	78%	69%	75%	84%	80%
2024		90%	95%	101%	76%	71%	82%	67%					

Q. **With these perspectives in mind, should the Commission use the CAISO-reported benefit estimate of EIM benefit proposed by Witness Earle for NPE rather than**

the value resulting from the PSE methodology the Company used in this case?

A. No. We should use the Aurora modeling used in PSE's most recently completed rate case, as we did in this case.

Q. Does this conclude your testimony?

A. Yes.