BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

EXH. CGK-14

CLINT G. KALICH

REPRESENTING AVISTA CORPORATION

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	WASHINGTON	DATE PREPARED:	05/01/2024
CASE NO.:	UE-240006 & UG-240007	WITNESS:	Clint Kalich/Scott Kinney
REQUESTER:	UTC Staff	RESPONDER:	Clint Kalich
TYPE:	Data Request	DEPT:	Power Supply
REQUEST NO.:	Staff – 192	TELEPHONE:	(509) 495-4532
		EMAIL:	clint.kalich@avistacorp.com

SUBJECT: Power Supply

REQUEST:
Re: Kinney Exh. SJK-1T at 67-68.

a. Please provide calculations of the "Forward (Forecast) Value" described on p. 67 and presented in Table No. 11.
b. If the "trend" referenced on p. 68, line 20 refers to anything longer than the 2018-2023 trend, please provide the referenced trend along with supporting workpapers.
c. Please explain why "a consistent and longer-term dataset valuing NPE over time to help illustrate its magnitude" (emphasis added) that uses a September baseline is a reasonable characterization of a portfolio forecast adjustment relevant to the two-year NPE forecast presented in this filing.
d. Does Avista claim that the proposed portfolio error value is necessary to accurately reflect reasonable and prudent power costs?
e. Does Avista admit that the difference between forecast NPE and actual NPE is subject to each of the following drivers of short-term variations that are within Avista's partial or full control?
   1. Plant operating practices
   2. O&M cost
   3. Hedging cost
   4. Fuel procurement practices
   5. Bi-lateral transactions outside the EIM/EDAM
f. Does Avista admit that the following long-term decisions impact the potential for "portfolio forecast error" in the sense that they set the degree to which NPE are influenced by drivers that are outside Avista's control?
   1. Long-term PPAs
   2. Long-term fuel supply agreements
   3. Resource planning
g. Please demonstrate how the use of historical differences between an emulated September valuation of Avista's portfolio with actual NPE costs excludes NPE variability driven by drivers listed in (d) and (e).
   1. If Avista admits that the proposed portfolio error value does not entirely exclude the identified NPE variability, please explain why it is reasonable for customers to prepay costs based on historical costs that may include variations from forecast rates that are driven by factors that are or have been within Avista's partial or full control.

RESPONSE:

a. All calculations for Table 11 are contained in the confidential workpapers of Clint Kalich within the file "240006-07-AVA-CGK-20-23 ForwardandActualPriceOpsForecasts v12-7 (C)" on the tab "Total NPE Summary." Table 11 is shown in cell Y6 of that tab and calculations for it may be found in the spreadsheet.

b. The trend referenced on Page 68 was not referencing Table 11 data. It was referencing the largest driver of our costs, the net value (i.e., market value of power generation less the fuel and variable costs of operation) of our thermal plants. The trend in this case is demonstrated back to 2010 in Table 12.

c. The 2-year NPE forecast in the case does not account for the significant variation the Company is witnessing today. As explained in testimony, forecast error always has existed, but nothing approaching the magnitude experienced in the last many years. The fact that our thermal plants have increased in annual value to customers from $15 to $30 million between 2010 and 2018, reference Table 12 in Witness Kinney's direct testimony, to more than $300 million projected in the case for calendar years 2024-26, illustrates the significantly greater exposure the Company and its customers have when building these high value projections into base rates. Higher values greatly lower NPE, but with higher value comes significantly higher risk that much of the estimated revenues will not materialize, meaning the Company will then absorb large variances in the deadbands. This risk is also magnified as we are now setting rates out two years, meaning rates are set using values based on price forecasts out up to 35 months into the future.

d. Yes. Given the magnitude of the forecast error, it no longer falls within the deadbands, illustrating much greater risk the Company accepts when including much higher thermal fleet value in the base net power supply expense. Any actions taken by the Company to manage costs in the deadband will be overwhelmed by newly magnified volatility mostly outside the control of the Company associated with thermal fleet and other values in our system.

e. The items listed can be affected by Company actions, and the Company does a great job acting on them to provide value to our customers and manage those risks within our control. However, the impacts of these actions are now small relative to the new volatility we are seeing today, and our ability to take protective actions within the market is greatly reduced relative to history, as explained in direct testimony and Illustration 1 below, an extension back in time of data presented in support of Table 11 discussed in answer subpart a. above. The extension of data back to 2011, and a rolling 5-year average helps explain how historical forecast error, measured as the delta between projected portfolio value (mark to market value) based on forward prices and value based on prices incurred during actual operations, has increased greatly over time. The 5-year rolling average of MTM was well below $15 million up and through 2020. Company actions based on items it can affect have the potential to help offset costs in the deadbands. But in more recent years there has been both a bias to actual portfolio value coming in greatly below its estimate using forward prices and a great increase in the magnitude of the volatility. As explained in the direct testimony of Company witnesses Kinney and Kalich, options to mitigate cost pressures have gone down in recent years, not up. Just as volatility rose drastically. Even were the Company afforded equal opportunity to mitigate cost pressures through its own actions, doing so when volatility increased so significantly means the Company simply cannot make up for the drastic shift in forecast error levels shown in the years up to 2018 (an average of $4 million of cost *below* emulated authorized) to the levels after 2018 (an average of $66 million above emulated authorized for 2018-2022, and $109 million above emulated authorized from 2019-2023).

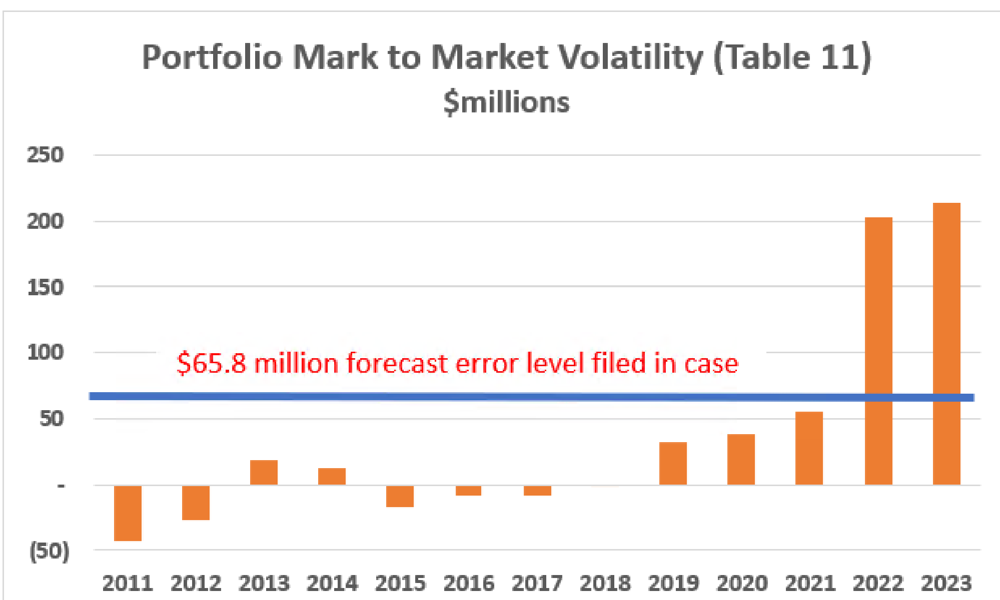
Illustration 1

Portfolio Mark-To-Market Volatility

Year	MTM Delta	5-yr Avg
2011	(42.19)	
2012	(26.88)	
2013	18.26	
2014	12.14	
2015	(17.03)	(11.14)
2016	(8.31)	(4.37)
2017	(8.02)	(0.59)
2018	(0.72)	(4.39)
2019	31.99	(0.42)
2020	38.79	10.75
2021	56.03	23.61
2022	202.69	65.76
2023	213.81	108.66

Illustration 1 shows average volatility increasing greatly over the past five years, and that on average the result was a cost born by the Company (rather than a variable oscillating between over and under estimation as occurred prior to 2018). This happened at the same time the Company's "package" of mitigation "tools" has been reduced by the loss of ability to find counterparties to hedge the rising thermal plant value included in rates. In 2022 and 2023 the volatility level has exceeded $200 million, or 2/3 of the value of our thermal fleet included in this rate filing. The forecast error variability, and our requested level of approximately 1/3 of this recent volatility, can be seen in Illustration 2 below.

Illustration 2



Page 3 of 6

It is important to expand on the loss of hedging opportunities here. The Company is not able to hedge out its resource portfolio at the beginning of the rate period to lock in the value of its thermal plants to minimize financial risk. The market isn't liquid enough to allow for that. Also, the Company and its customers cannot afford the collateral costs facilitating the transactions with current interest rates.

The bottom line is that while Customers obtain the huge benefits of much lower net power supply expenses driven by the benefits of including higher thermal plant operating margins, the Company does not see a similar benefit. As explained in the response to part f below, the $66 million forecast error included in this case is <u>less than one quarter</u> of the incremental value of the thermal fleet included for customers in this case when compared to the last case.

In summary, the Company is exposed to greatly higher volatility and, absent the elimination of the deadband and 95/5 sharing, and/or a factor to reflect much higher forecast error, it is being expected to absorb an oversized share of the volatility. This is not a fair outcome; one party (customers) gains a large windfall, while the other (the Company) absorbs an outsized share of increased risk associated with rising markets and volatility, all of which is outside the Company's control.

f. See response to Part e above. The actions listed cannot protect against the market conditions occurring in the past few and current years. Our resource acquisitions are based on IRP trends and generally exercised through competitive acquisition, such as RFPs, based on the best information known at the time. Once longer-term positions are taken, the Company must manage the new resources within the market conditions that exist. New market conditions can be considered in the future when new resources are acquired, but this offers no guarantees that the new actions will account for large market moves like we have seen in recent years.

   Staff should notice that our most recent acquisitions were not the thermal plants driving the most customer value in this case, and generating the forecast error being addressed through an adjustment to NPE. All new additions have been clean energy with no fuel cost component. Again, our power supply expenses included in this rate filing are *hundreds of millions lower* than in past filings due to our legacy thermal plants. As shared above, the thermal fleet is reducing NPE by over $300 million per year instead of the historical $15-$30 million. This is great for customers! But the value is from long-term investments made years ago, not any actions of late. However, along with base rates potentially $300 million lower than they otherwise might be, there is a need for a fair recognition of the likelihood that projected power costs will be higher than included in our case, and that current deadbands and associated sharing is no longer fair to the Company and no longer meaningfully provides incentives to manage large cost fluctuations that the Company cannot control. Another way to look at the forecast error component in the broader context of setting NPE is that the $66 million forecast error component included in this case is <u>less than a quarter</u> of the increased value the plants offer to customers in this filing relative to prior cases.

g. Avista is not claiming in this case the items listed do not exist or that it has no ability to affect costs. Please see Avista's response to Staff-DR-170, discussing prudent actions of the Company. Indeed, those prior actions have previously been vetted through the ERM review process and the Company's hedging practices have been examined by the Commission. Instead, the Company is highlighting <u>new risk</u> that is beyond our control. Avista disagrees that the concept of forecast error is a "prepay." It is simply a factor necessary to arrive at a normalized power supply expense over time when we are valuing the thermal fleet hundreds of millions of dollars higher in the case than the last one. Absent this adjustment, there will be a chronic under-collection of costs at the same time customers are receiving a windfall benefit from thermal plant operation margins when compared to previous cases. Data presented in our case illustrates how modeled customer value and risk has changed over time. Table 12 of Witness Kinney's testimony illustrates how variation in thermal plant value shifted from a handful of millions from 2012 through 2017 to many tens of millions today. This is at the same time net power supply expenses are being reduced by more than $300 million instead of values in the $15-$25 million over the same period. The Company is at significantly greater risk of thermal plant value under-performing when the value in the case is $300 million, than when the value in the case is $15 or $20 million. A 10% drop from $15 million in thermal plant value is $1.5 million and falls within the first sharing band of the ERM. A 10% drop from $300 million is $30 million, a value that not only exceeds the deadband, but if experienced would move the Company through all of the deadbands, as in Illustration 3 below. See Staff-DR-192 Attachment A.

Illustration 3

Energy Recovery Mechanism Comparisons

On Company Earnings ($millions)

Scenario 1: Authorized Is $20MM Lower Than Actual Costs Prior to Thermal Fleet Value Change

	Annual Expense Scenario			Energy Recovery Mechanism					
No.	Authorized	Actual	Delta	Band 1	Band 2	Band 3	Total	Delta	Note
1	100.00	80.00	(20.00)	4.00	1.50	1.00	**6.50**		In Base Case, Assume Costs Have Otherwise Come In $20MM Below Authorized
2	100.00	81.50	(18.50)	4.00	1.50	0.85	**6.35**	(0.15)	Impact Of 10% Change in $15MM Thermal Fleet NPE Value
3	100.00	110.00	10.00	(4.00)	(3.00)	-	**(7.00)**	(13.50)	Impact Of 10% Change in $300MM Thermal Fleet NPE Value

Scenario 2: Authorized Equals Actual Costs Prior to Thermal Fleet Value Change

	Annual Expense Scenario			Energy Recovery Mechanism					
No.	Authorized	Actual	Delta	Band 1	Band 2	Band 3	Total	Delta	Note
1	100.00	100.00	-	-	-	-	**-**		In Base Case, Assume Costs Have Otherwise Come In $20MM Below Authorized
2	100.00	101.50	1.50	(1.50)	-	-	**(1.50)**	(1.50)	Impact Of 10% Change in $15MM Thermal Fleet NPE Value
3	100.00	130.00	30.00	(4.00)	(3.00)	(2.00)	**(9.00)**	(9.00)	Impact Of 10% Change in $300MM Thermal Fleet NPE Value

As shown in Scenario 1 of Illustration 3, a case where authorized costs were, prior to the thermal fleet value change, coming in $20 million below authorized, a 10% change from a historical $15 million thermal fleet benefit in NPE would affect the Company by approximately $150,000, as the value delta would impact the 10% sharing band in this example where prior to the thermal fleet change actual costs were trending $20 million below authorized costs. However, with a $300 million thermal fleet benefit included in NPE (approximately what is included in this case) a 10% change in thermal fleet value would move the Company through all sharing bands, resulting in a $13.5 million negative impact on the Company's position in the ERM. The impact is a 90-fold increase in impact that outweighs all other prior positive impacts (assumed in this example to be those both taken proactively by the Company to lower costs such as financial hedging and optimization, and other portfolio impacts such as better-than-expected hydro conditions that are outside Company control).

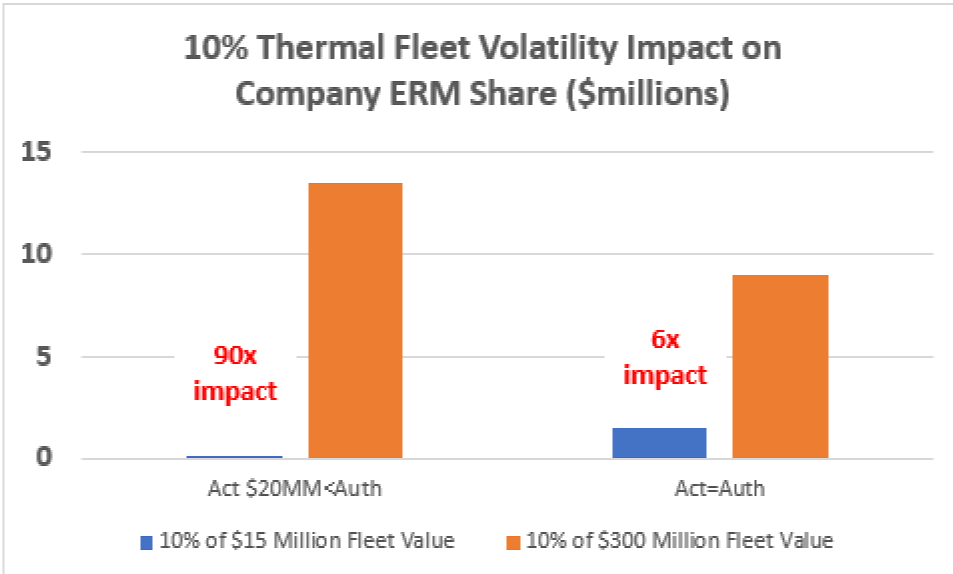
In Scenario 2 of Illustration 3, actual costs are assumed to be coming in at authorized levels. The 10% movement in a $15 million thermal fleet value is absorbed 100% by the Company in the first deadband, or $1.5 million. However, at 10% of a $300 million thermal fleet value, this single change

Page 5 of 6

results in movement through all three deadbands, and the Company absorbs $9 million, a 6-fold increase in impact. See Staff-DR-192 Attachment A.

The same data can be viewed graphically in Illustration 4.

Illustration 4



Page 6 of 6