BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-23____

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, present position with Avista Corporation, and business address. A. My name is Scott J. Kinney. I am employed as the Vice President of Energy Resources at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational and professional background?

A. Yes. I graduated from Gonzaga University in 1991 with a Bachelor of Science in Electrical Engineering and I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending the first eight years of my career with the Bonneville Power Administration. I have held several different positions at Avista beginning as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a Supervisor and Operations Support Engineer. In 2004, I was appointed as the Chief Engineer, System Operations and as the Director of Transmission Operations in June 2008. I became the Director of Power Supply in January 2013 and Vice President of Energy Resources in September 2022.

The Energy Resources group is primarily responsible for producing or procuring the electricity and natural gas to serve our customers' needs, including the construction, operation, and maintenance of our generation facilities and the optimization of those electric and natural gas facilities for the benefit of our customers.

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

A. My testimony offers an overview of the history of the ERM and provides a summary of the factors contributing to the power cost deferrals during the 2022 calendar year review period. I provide an overview of the documentation the Company has provided in work papers, which the Company agreed to provide in the ERM Settlement Stipulation approved and adopted in Docket No. UE-030751. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes, I am sponsoring one exhibit. Exh. SJK-2 contains five pages from the Company's December 2022 Monthly Power Cost Deferral Report previously filed with the Commission in Docket UE-011595. These five pages show the deferral calculations for the period of January 2022 through December 2022. Page 1 of Exh. SJK-2 shows the calculation of the deferral, pages 2 through 4 show the actual expenses and revenues, and page 5 shows the retail revenue adjustment.

Detailed workpapers supporting the tables and other calculations in my testimony have been provided in electronic format to the Commission, and other parties, coincident with this filing. Workpapers also provide detailed analysis of the various components which resulted in the actual vs. authorized variances.

Q. What was the ERM deferral amount in 2022?

A. For the 2022 calendar year, actual net power costs were more than authorized for the Washington jurisdiction by $48,834,582 (excluding interest). The deferral in the customer surcharge direction for 2022, amounted to $37,951,124. Pursuant to the mechanics of the ERM, the Company absorbed $10,883,458 of increased power costs in 2022.

Q. Are other witnesses sponsoring testimony on behalf of Avista?

A. Yes. Company witness Mr. Miller provides testimony concerning the monthly deferral entries, the deferral balance, and describes the overall proposed net increase to customers.

II. OVERVIEW AND HISTORY OF ERM

Q. Would you please explain the history of the ERM and the annual filing requirement?

A. Yes. The ERM was approved by the Commission's Fifth Supplemental Order in Docket UE-011595, dated June 18, 2002, and was implemented on July 1, 2002. That Order approved and adopted a Settlement Stipulation (UE-011595 Stipulation) that explained the recovery mechanism and reporting requirements. Pursuant to the UE-011595 Stipulation, the Company is required to make an annual filing on or before April 1 of each year. This filing provides an opportunity for Commission Staff and other interested parties, to review the prudence of the ERM deferral entries for the prior calendar year. Interested parties are provided a 90-day review period, ending June 30 of each year to review the deferral information. The 90-day review period may be extended by agreement of the parties participating in the review, or by Commission order. Mr. Miller describes why such an extension is not appropriate in this annual review.

Avista's first Annual ERM Filing covered the six-month period of July 1, 2002 through

December 31, 2002. Avista has made ERM annual review filings for each subsequent calendar year period. Last year's annual ERM filing covering the 2021 calendar year was filed March 31, 2022 in Docket UE-220232.

III. OVERVIEW OF POWER SUPPLY OPERATIONS

Q. How does Avista, generally, manage its power supply resources?

A. Avista Utilities conducts electric planning, procurement, sales and power resource management activities to assure an adequate supply of electricity to serve customer and other load obligations, as well as to optimize its generation and transmission resources. As one can imagine, numerous variables affect short-term power supply positions and prices. As such, the Company employs an Energy Resources Risk Policy to recognize and actively manage the interaction and dynamics amongst these variables by establishing processes for predicting future load and obligation requirements, resource availability, and management of the expected net surplus or deficit short-term and immediate-term positions.

It is understood that many factors cause loads to differ from estimates. It is also understood that each of Avista's generating resources has inherent variability because of streamflow and water storage conditions (for hydroelectric plants), mechanical limitations, transmission constraints, fuel availability and delivery constraints, ambient conditions, environmental and permit allowances, and other factors. Avista's Energy Supply department is responsible for fuel management, optimizing the use of electric resources including wholesale power contracts, and dispatching power resources to meet load obligations and providing good stewardship of electric resources.

Energy resource planning involves significant modeling, assumptions, and estimates to predict future situations. Actual loads are influenced by many factors and therefore rarely match forward estimates. Balancing generation to match load obligations requires constant attention, and its variability dictates that flexibility be maintained at all times. It is necessary to buy and sell energy (or financially equivalent derivative transactions) in hourly, daily, monthly and longer increments, and adjust dispatch plans to meet prevailing conditions. As such, Avista utilizes all power and fuel transactions authorized in its Risk Policy to provide reliable and affordable service to Avista's electric loads and contract obligations and seeks to optimize additional opportunities associated with Avista's energy resources.

Q. What types of transactions will Avista enter into, as detailed and authorized in the Company's Risk Policy?

A. The following are examples of the types of transactions permitted in the context of managing Avista's energy resources and serving the Company's obligations in the short-term and intermediate-term horizons:

- Scheduling and dispatching energy resource facilities owned or controlled by Avista.
- Transactions with other parties for physical delivery of capacity or energy, including fixed price and indexed or formula-priced transactions.
- Ancillary services, such as reserves, load-following, generation imbalance, and others.
- Transportation, transmission, storage and capacity obligations, and rights.
- Bilateral forward transactions with approved counterparties.
- Future contracts traded on an established commodities exchange.
- Swap agreements as a tool for fixed price financial hedges.
- Transactions that allow Avista to buy or sell electricity or natural gas at Avista's discretion.
- Exchange agreements (forward commodity agreements expected to be settled with return of the commodity rather than cash, either with or without associated settlement prices).
- Fuel (supply, delivery, storage, excess fuel disposition) related to specific electric

generating facilities in which Avista has an ownership or contractual interest including natural gas, coal, biomass (wood waste), and related emission allowances.

- Streamflow and water storage rights and benefits related to Avista-owned or contracted hydroelectric generation stations including coordination of the related river systems.

Q. How does Avista optimize its energy resources for the benefit of its customers?

A. Avista optimizes its energy resources in a number of ways. Electric resource optimization involves choices amongst several variables. The Company assesses these variables, detailed below, to select and execute an appropriate mix for short-term and intermediate-term objectives. Intra-month activity during the current month to serve loads, optimize resources, and participate in the electric market is reported after-the-fact in the daily position report. Electric optimization variables include:

- Scheduling and dispatching of available Avista generating units as indicated by relevant plant parameters.
- Buying fuel to operate a generating facility or selling fuel already available to decrease or eliminate generation from a unit.
- Storing or using water for hydroelectric generation that maximizes expected generation value and arranging for water from or for other hydroelectric plants in the coordinated river system.
- Buying, selling or exchanging electricity in the wholesale market from/to other utilities, power marketers, or independent power producers, including displacing purchases and sales available to the Avista balancing area.
- Buying or selling financial contracts that hedge electric purchase or sale prices and open positions.
- Obtaining transmission rights as may be needed to deliver or receive output to or from any Avista generation source or any market and selling surplus transmission rights.
- Buying and selling the natural gas basis spread based on natural gas transport contract rights.
- Participating in organized markets such as the Western Energy Imbalance Market, to take advantage of regional resource diversity

Q. Does the Company have an active hedging program?

A. Yes. The Company has a mature hedging program and employs a Power Supply Hedge Requirements Report tool (PSHRR) to inform transactions. The PSHRR is an analytic tool to guide power supply hedging decisions in the short-term and forward periods. It provides a process to systematically reduce open positions with forward transactions by buying for expected shortages and selling expected surpluses. An "open" position for this purpose is the forecasted monthly financial position that is not covered by fixed price physical or financial transactions, i.e., the surplus or deficit that is subject to price risk. The plan provides guidance but may not be followed rigidly when management decisions or market conditions warrant other actions, no action, or simply a delay in taking action.

IV. SUMMARY OF DEFERRED POWER SUPPLY COSTS

Q. How did actual power costs differ from the authorized level of power costs, what were the amounts deferred, and what amount was absorbed by the Company during 2022?

A. During 2022, actual net power costs were higher than the authorized net power costs for the Washington jurisdiction by $37,951,124 (surcharge). Under the mechanics of the ERM, the first $4.0 million of net power supply costs above or below the authorized level is absorbed by the Company. When actual costs exceed authorized costs by more than $4 million (surcharge direction), as is the case with this filing, 50% of the next $6 million of difference in costs is absorbed by the Company, and 50% is deferred for future recovery from customers. When actual costs are less than authorized costs (rebate direction), 25% of the next $6 million of difference above the $4 million dead band is absorbed by the Company, and 75% is deferred for rebate to customers. If the difference in costs exceeds $10 million, either in the surcharge or rebate direction, 10% of the amount above $10 million is absorbed by the Company, and 90% is deferred.

Pursuant to the mechanics of the ERM, the total difference between actual and authorized power supply expense was $48,834,582. Of this total, the Company absorbed $10,883,458 and a deferral was recorded in the amount of $37,951,124 (excluding interest), as shown in Table No. 1.

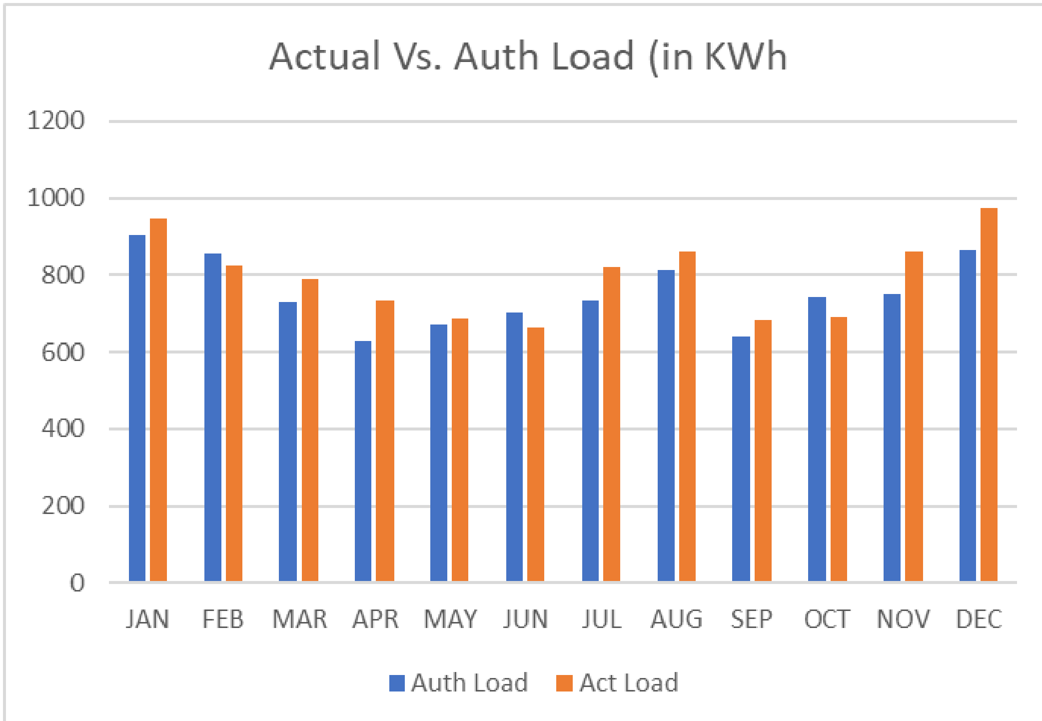
Table No. 1 - ERM Results

	Total	Absorbed (Avista)	Deferred (Customer)
First $4M at 100%	$ 4,000,000	$ 4,000,000	$ -
$4M to $10M at 25% (rebate)		$ -	$ -
$4M to $10M at 50% (surcharge)	$ 6,000,000	$ 3,000,000	$ 3,000,000
Over $10M at 10%	$ 38,834,582	$ 3,883,458	$ 34,951,124
	$ 48,834,582	$ 10,883,458	$ 37,951,124

Q. Please summarize the primary components which contributed to actual power supply expenses being higher than the authorized level during the review period?

A. At a very high level, the primary contributor to the increase in power supply expense was an increase in customer load in response to unusually hot or cold temperatures, combined with very high electric and natural gas prices. For the year, actual load exceeded the authorized level by approximately 57 aMW. The monthly shape of these variances is provided in Figure No. 1 below:

<u>Figure No. 1 – 2022 Monthly Load Variance Compared to Authorized</u>



Dependent upon economics and resource availability, the Company utilized a mix of resources and market purchases to meet the demands of these additional loads. The variances generated by each resource component provide the basis for the variance analysis in this testimony. Table No. 2 below provides the primary components of the variance analysis. Please note in all variance tables below, a positive number represents unfavorable; a negative number indicates favorable.

Table No. 2 – 2022 Variance Factors (+) Unfavorable (-) Favorable

	Washington Share						
		Cost Variance		Generation Variance		Total Variance	
1	Net Purchases/Sales	$	(1,458,940)	$	(76,356,012)	$	(77,814,952)
2	Natural Gas Plant Generation	$	47,719,268	$	20,683,230	$	68,402,498
3	Thermal Generation	$	4,645,463	$	(2,053,012)	$	2,592,451
4	Wind Generation	$	(1,878,282)	$	7,817,163	$	5,938,881
5	Hydroelectric Operations	$	6,001,710	$	8,021,909	$	14,023,619
6	Other	$	3,007,188	$	-	$	3,007,188
7	Net Transmission Revenue	$	(5,583,953)	$	-	$	(5,583,953)
	Subotal	$	52,452,454	$	(41,886,723)	$	10,565,731
8	Retail Revenue Rate Adjust	$	(3,617,872)			$	(3,617,872)
9	Load Variance			$	41,886,723	$	41,886,723
10	Total Variance	$	48,834,582	$	(0)	$	48,834,582

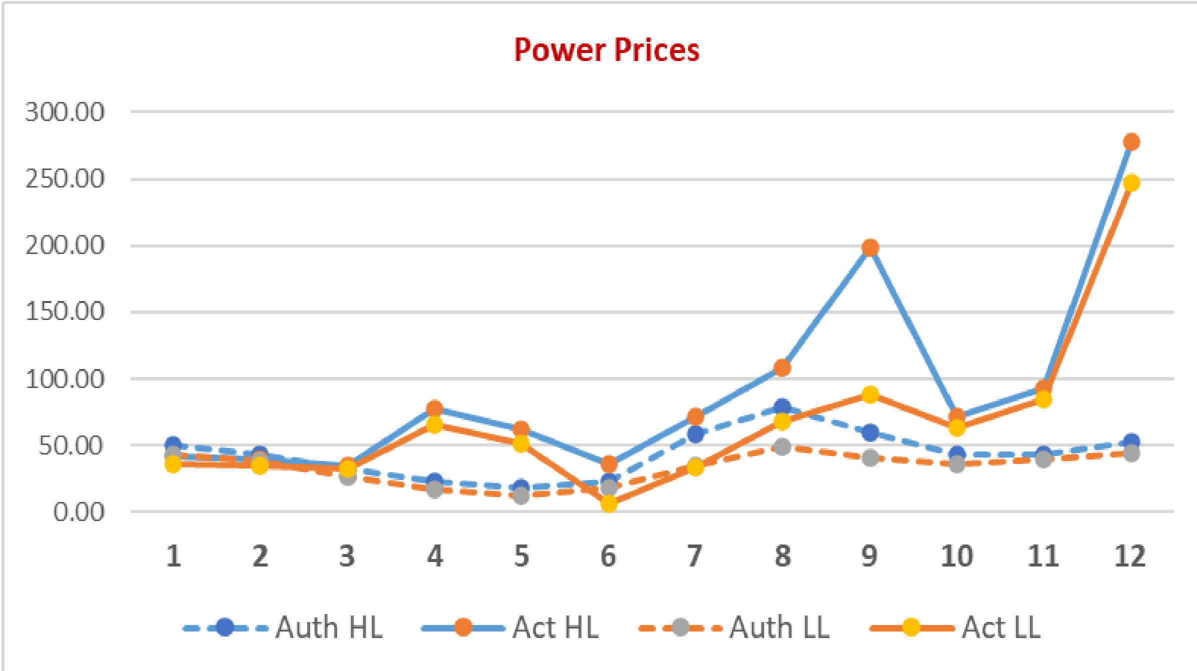
For purposes of this variance analysis, workpapers provided by Avista differentiate between the "cost variance" (which represents the price/quantity variance when comparing the actual values to authorized as recorded to the general ledger), and "generation variance"[1] (which represents the value each resource contributed towards meeting customer load requirements). The cost variance can be further broken down by price variance (change in price multiplied by actual price) and volume variance (change in volume times authorized price).

The primary months which contributed to the overall ERM deferral variance were the summer months of July - September when record high temperatures were experienced not only in Avista's service territory but also within the entire Western Region, in the spring month of April, and winter months of November and December when record cold temperatures were experienced. You will note I reference these time periods several times throughout my testimony.

[1] Workpapers provide the generation variance calculation. For ease of reference the formula is as follows: Gen.Var = (actual HL MWh - authorized HL MWh) * Actual HL price + (actual LL MWh - authorized LL MWh) * Actual LL price.

The generation variance essentially reallocates the variances to the applicable resource to represent the market value the plants provided towards meeting load requirements. As such, the variance is a function of both generation deviations and the estimated market price of power. This calculation is not intended to be an "exact science", but rather a proxy value for Heavy Load (HL)/Light Load (LL) of each component in Avista's resource mix as compared to authorized. The primary purpose is to provide an indicator as to how each component of the Company's overall resource stack, adjusted up or down, ultimately met changing load requirements. Several factors may have impacted these variances including market conditions, hydro conditions, maintenance cycles, weather, and temperatures, among others. It is important to recognize that Avista manages its resources as an overall portfolio and that while this variance analysis will take a look at each individual component, in actual operations several different resources and inputs are evaluated simultaneously in order to ensure customers' needs are addressed in the most economic and efficient manner. Coincident with the load determination, Avista also ensures resources are optimized where possible to capture benefits for customers to reduce overall costs. The proxy value of HL/LL market prices, as compared to authorized is illustrated in Figure No. 2 below:

<u>Figure No. 2 – Power Prices in 2022 as Compared to Authorized</u>



Q. Based on the information provided in Table No. 2 above, the primary contributor in the <u>rebate</u> direction for 2022 was related to item number *<u>(1) Net Purchases/Sales</u>* ($77,814,952 rebate). Please provide additional context for this variance.

A. In addition to the generation from Company-owned or operated resources, Avista engages in both short-term market transactions (purchases and sales) as well as long-term structured transactions with counterparties. In comparison to authorized, net power purchases/sales were higher than authorized by 97 aMW. When evaluating each component separately, purchased expense was approximately $43.7 million more than authorized, however, sales revenue was more than authorized by $45.1 million, netting to total sales exceeding purchased costs by approximately $1.4 million.

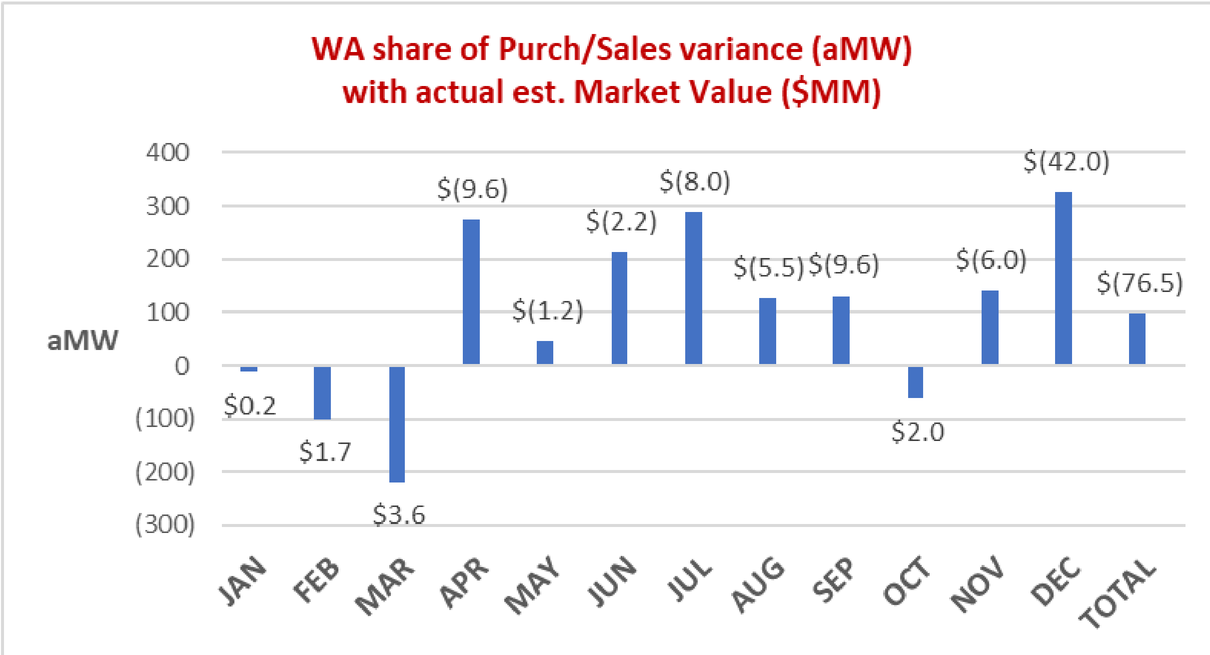
The total cost of purchases of $43.7 million can be further broken down into the volume and price of purchases which exceeded authorized. Particularly in December and

August in response to extreme temperature deviations, Avista purchased more than authorized resulting in higher expense than authorized by approximately $34.2 million. Typically in those times when purchases were higher than authorized, so was the price of those purchases, resulting in even higher total purchase expense when compared to authorized by an additional $9.5 million. For example, in December, loads were approximately 151 aMW higher than authorized loads and average heavy load prices were $278 per MWh as compared to authorized of $52 per MWh, resulting in net expense exceeding authorized expense by approximately $19 million.

Total sales revenue for 2022 was approximately $120 million compared to the authorized level of $74.9 million for a net increase of $45.1 million. Particularly in periods of time when prices were high, Avista was able to capture the benefit of these higher prices due to sufficient resource availability after load was served. These sales are the result of hundreds of transactions, some of which may have been executed as part of the Power Supply Hedge Revenue Requirements model, or as part of dispatch decisions made on a daily, hourly, and monthly basis based on several factors previously identified in my testimony.

The generation variance corresponds with the volume variance described above, essentially resulting in a favorable price variance of $76.3 million. Figure No. 3 shows the market value of these net market purchases/sales in the form of the generation variance of $76.5 million. This generation variance is additive to the previously mentioned $1.5 million for a total net purchase variance as compared to authorized of $77.8 million in the rebate direction.

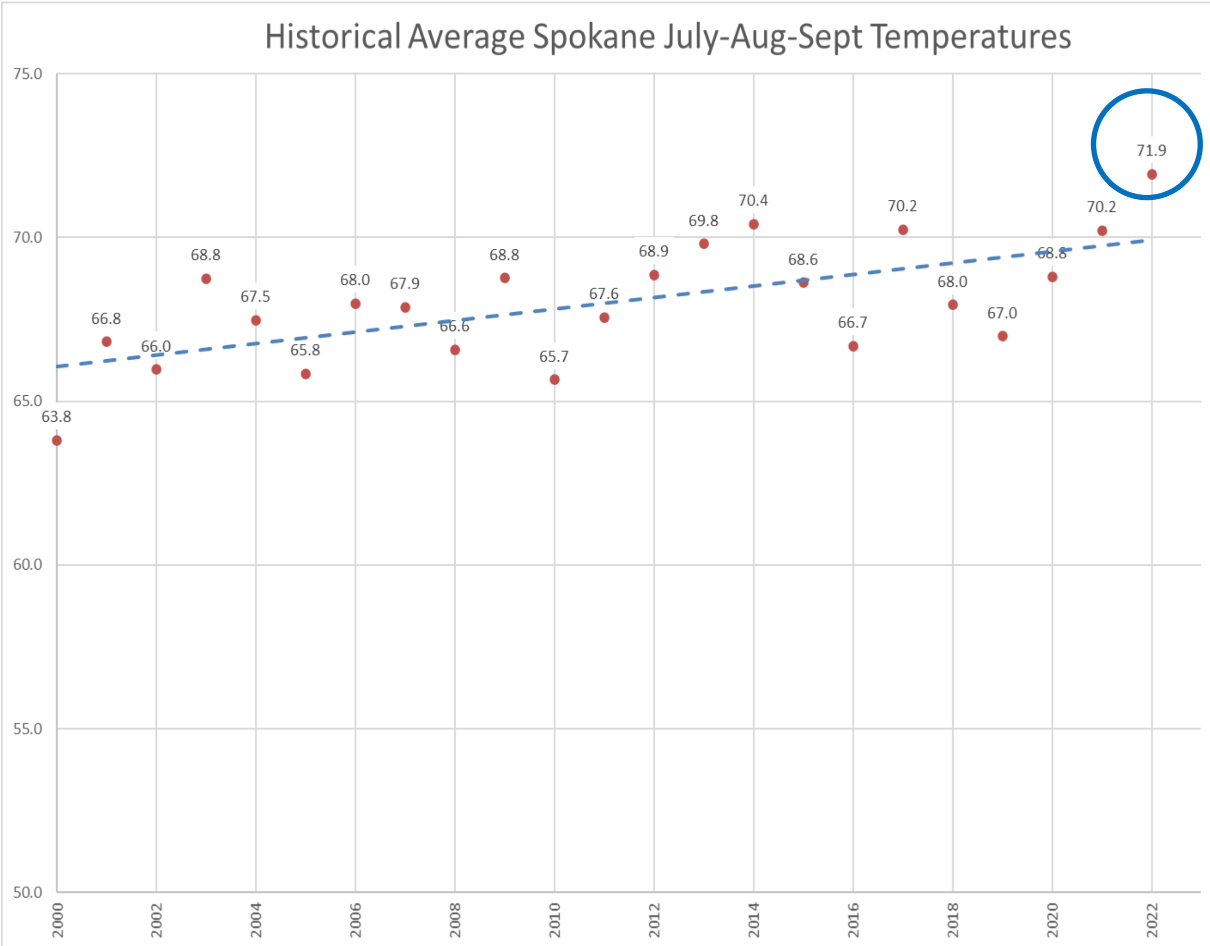
Figure No. 3 – Net Purchase/Sale Generation Variance aMW and Cost



Q. Please provide additional context on conditions for 2022, specifically prices, weather, and loads.

A. As previously mentioned, there were several periods of the year impacted by unusually cold or warm weather. In the summer months of July – September temperatures were well above normal with the average temperature at 71.9 degrees, which was the highest in 20 years as illustrated in Figure No. 4 below.

Figure No. 4 – Historical Average Spokane Temperatures Summer 2022

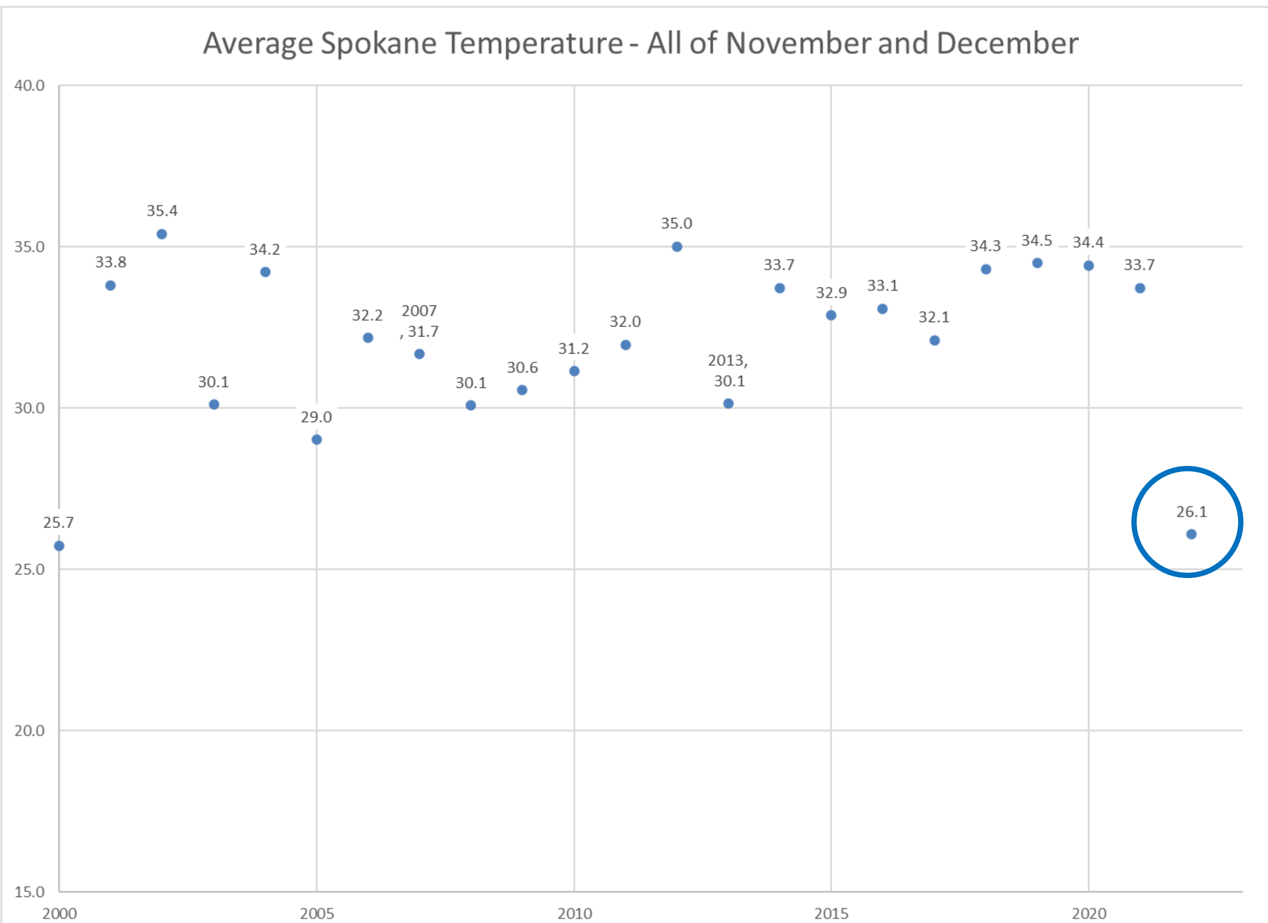


These temperatures resulted loads that were approximately 235 aMW higher than average for these months. During this higher demand period heavy load prices peaked at $198 per MWh for the month of September as compared to the authorized of $53 per MWh.

In the spring of 2022, April temperatures were among the sixth coldest on record as measured at the Spokane airport. On average, Spokane was 4-6 degrees below normal for the majority of the month, resulting in increased demand and high electric prices. Compounding this increased demand were poor hydro conditions, as the snowpack remained in the mountains. As an example of the impact on regional prices, in one week alone, at the California-Oregon

Border heavy-load power increased $40 per MWh from April 7 to April 14. The impact of these high prices was reflected in a deferral of approximately $6.5 million in April, approximately 13% of the total ERM deferral for 2022. In the winter months of November and December, on a combined basis, temperatures averaged 26.1 degrees as shown in Figure No. 5. This was the lowest temperature since 2000 and the fourth lowest in 75 years.

<u>Figure No. 5 – Average Spokane Temperature November and December</u>



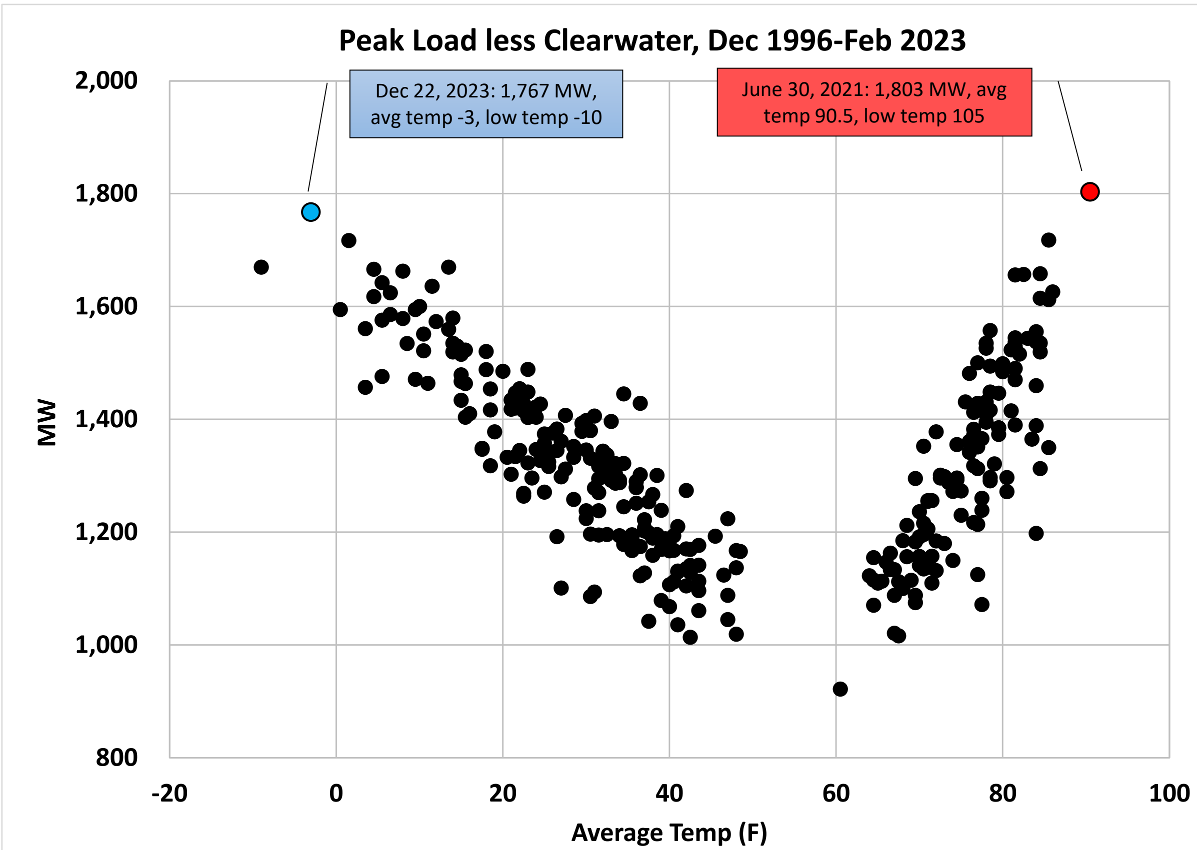
These low temperatures impacted the entire region and resulted in peak electric loads in several Pacific Northwest Utilities including:

- Avista – 1803 MW
- Grant PUD – 971 MW
- Douglas PUD – 300 MW

- Chelan – 553 MW (temperatures reached -2 degrees)
- Idaho Power – 2,604 MW

Avista's peak load was second only to the Heat Dome event of June 30, 2021. The correlation between load and temperature is illustrated in Figure No. 6 below.

<u>Figure No. 6 – Load Vs. Average Daily Temperature</u>



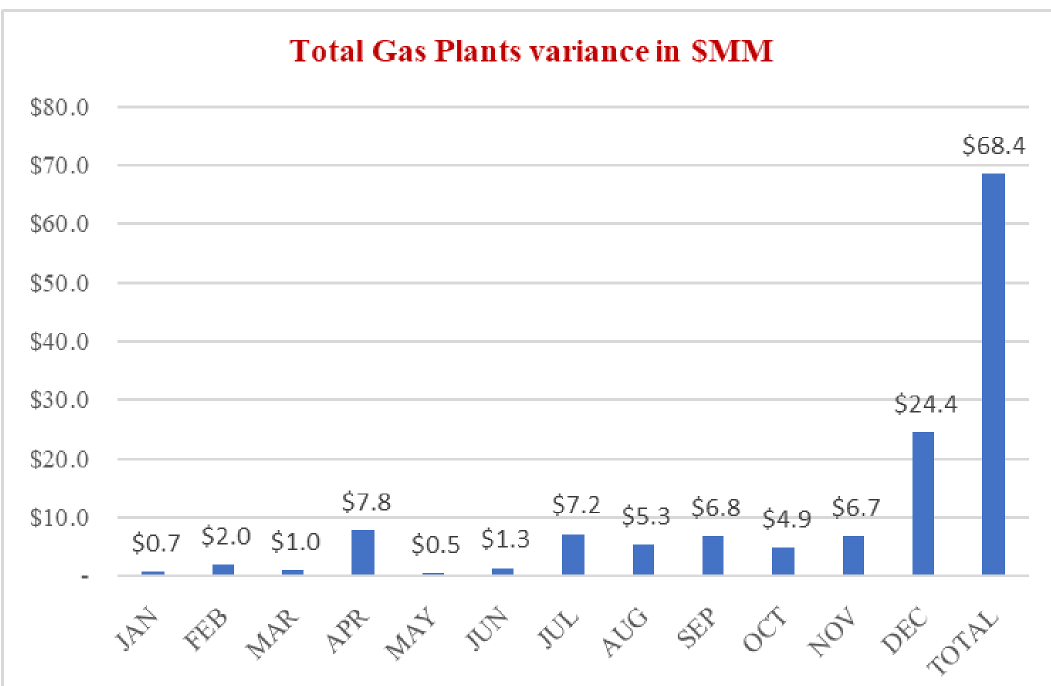
To compound the high demand in December, on the supply side, these cold temperatures resulted in less hydroelectric generation than included in authorized in several of the river systems in the Pacific Northwest including the Clark Fork, Spokane River Systems, and Columbia River. For instance, in November the Clark Fork generation was only 79% of normal generation – the lowest since 2007 and December was not much better at 85% of normal. The temperatures were such that all precipitation fell as snow and no low level snow melted, which impacted river flow and associated hydro generation.

The impact of the combination of these supply and demand conditions was significant. Customer load in November and December alone exceeded authorized customer load by a staggering 468 aMW, resulting in an ERM deferral of $34.8 million ($27.5 million in December alone).

Q. Please turn now to the primary contributor to the variance *Item No. 2 Natural Gas Plant Generation* ($68,402,498 surcharge) listed in Table No. 2?

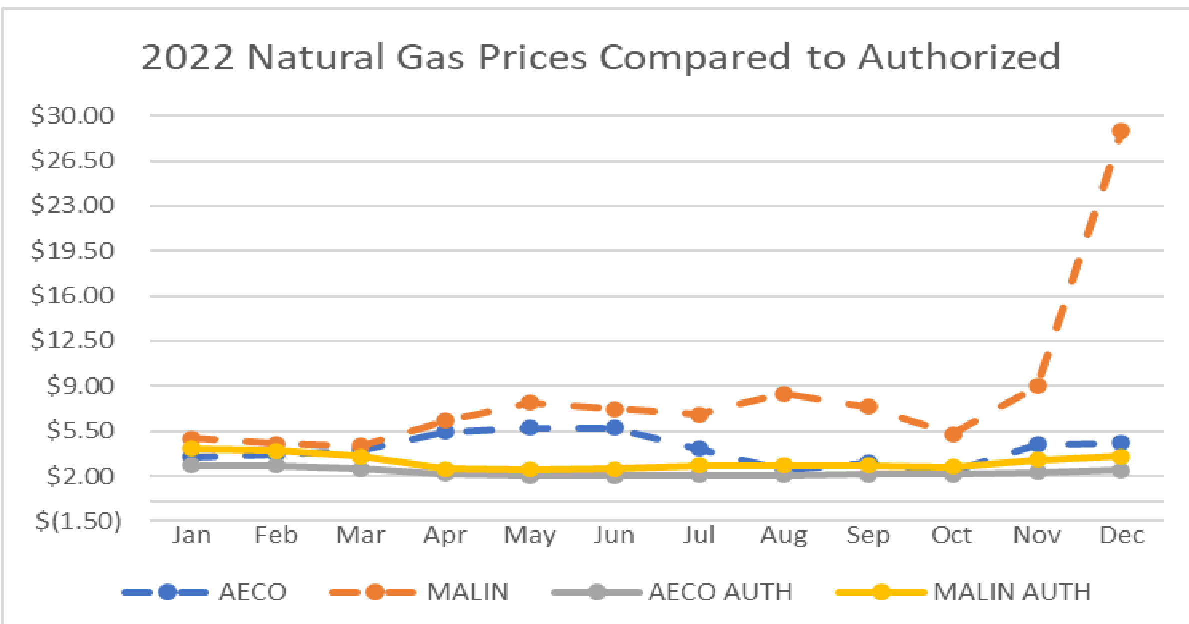
A. Natural Gas Plant Generation is primarily comprised of Coyote Springs II (CS2) generating station and the Power Purchase Agreement (PPA) associated with the Lancaster Combustion Turbine (CT). Also included in the overall natural gas generation portfolio, categorized as "Other CT", are Boulder Park, Rathdrum, Kettle Falls CT, and Northeast CT. In total, the cost variance related to Avista's natural gas generation was approximately $68.4. million higher than authorized.

Figure No. 7 – Natural Gas Plant Variance



In 2022, natural gas generation was less than the amount of generation in authorized by aproximately 53 aMW. By generating less than authorized on a volumetric basis, the Company incurred approximately $6.5 million less in expense than authorized. However, as illustrated in Figure No. 8 below, the natural gas fuel price of this generation was materially higher than authorized, resulting in costs exceeding authorized by approximately $54 million. The net result of lower generation and higher prices was actual costs exceeding authorized by approximately $47.7 million.

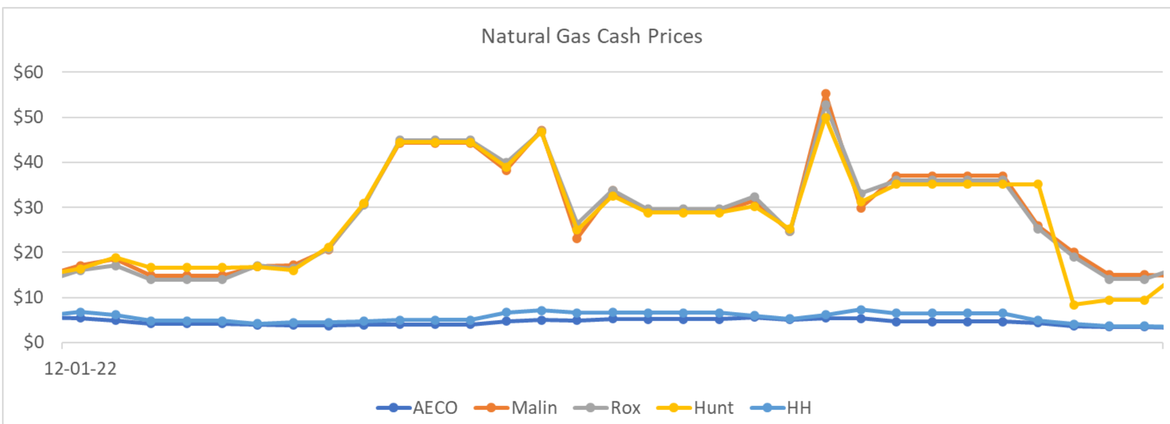
Figure No. 8 – Natural Gas Prices Compared to Authorized



December natural gas prices were the highest since 2000, reaching above $50.00 per dekatherm on December 21, 2022. Several factors impacted these prices including increases in natural gas demand caused by previously mentioned below normal temperatures, higher power gas burn due to reduced hydro generation, and lower than normal storage levels in the entire West which further decreased supply. According to the Energy Information Administration (EIA), natural gas consumption in the Pacific Northwest and California spiked by 23% in the first three weeks of December compared to the second half of November.[2] Data from Point Logic shows that in the electric power sector, natural gas consumption increased 14% over the same timeframe."[3]

Figure No. 9 below provides a closer look at the natural gas prices for December 2022. For December 2022, natural gas prices reached a high of $58 per dekatherm during a period of time with the highest demand. The price variance for natural gas generation in December alone, at these prices, resulted in costs exceeding authorized by approximately $17 million, which accounts for approximately 36% of the total annual ERM deferral of $47.7 million.

<u>Figure No. 9 – December 2022 Natural Gas Prices</u>



An additional $20.7 million in deferral balance is related to higher than authorized natural gas prices associated with gas generation dispatch to meet customer load.

Q. Turning back to the components listed in Table No. 3, would you please describe the <u>surcharge</u> variance related to *<u>Item No. 3 Thermal Generation</u>* ($2,592,451 surcharge)?

A. Yes. Item No. 3- Thermal Operations, is comprised of the Colstrip Generating

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[2] Clearing Up, February 24, 2023, No. 2095, Pg. 8

[3] Western U.S. natural gas reaches highest spot prices since 2000 - CompressorTECH² (compressortech2.com)

Station (Units 3 and 4) and the Kettle Falls Generating Station. For both plants combined, total expense exceeded authorized by approximately $2.6 million.

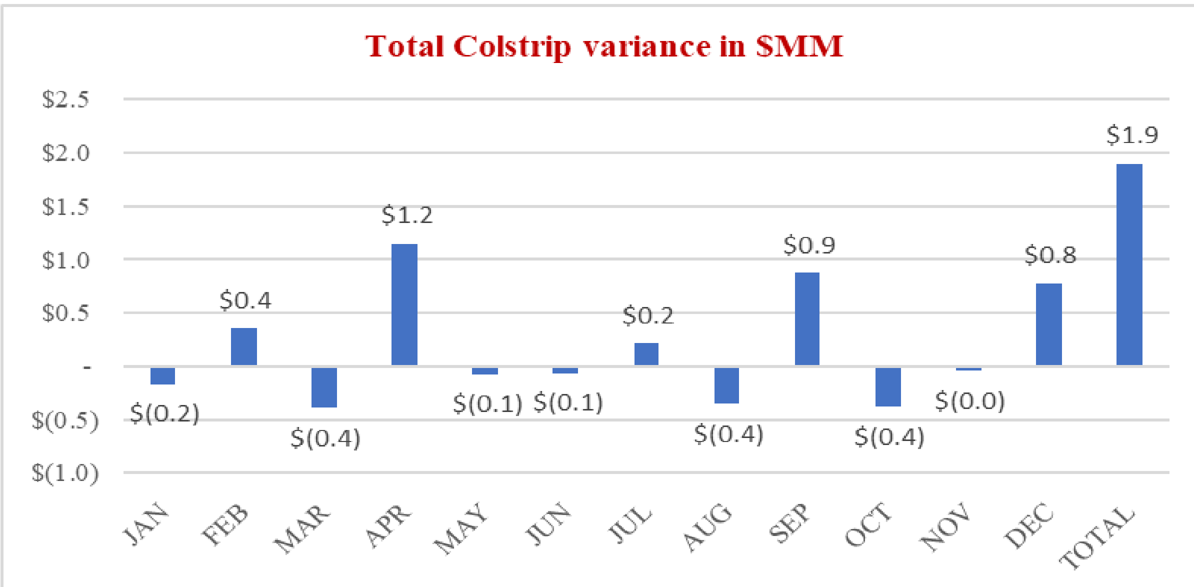
<u>Table No. 3 – Thermal Generation Reconciliation</u>

Thermal Generation						
	Cost Variance		Generation Variance		Total Variance	
1 Kettle Falls	$	1,017,590	$	(324,118)	$	693,472
2 Colstrip	$	3,627,873	$	(1,728,894)	$	1,898,980
3 Total	$	4,645,463	$	(2,053,012)	$	2,592,451

Kettle falls generation was very close to authorized, however, the cost to generate was approximately $1.0 million higher than authorized due to higher fuel prices as illustrated in the Cost Variance in Table No. 3. Although for the year the total variance netted to only 1 MW of generation above what was included in authorized, the timing associated with when this generation was dispatched, combined with higher wood fuel prices, was the primary contributor to this total variance. In addition, the value of the additional generation in meeting customer loads, when priced at market, offset the increased expense and reduced the net impact to approximately $700,0000.

Colstrip's primarily expense variance is due to the price of coal utilized as generation fuel. The contractual price is $31.41 cost per ton compared to an authorized level of $16.89 cost per ton. The contract price includes a base price that is adjusted annually based on six inflation adjustments for labor and benefits, diesel fuel, electricity, explosives, mining machinery and equipment, and implicit price deflator. In total the impact of these inflation adjustments far exceeded those anticipated when setting the authorized base. The net result was a fuel expense which was higher than authorized by approximately $4.7 million. Colstrip was dispatched, however, less than modeled in authorized which reduced the impact of these higher prices by approximately $1.1 million, resulting in net costs higher than authorized by $3.6 million. The value of this generation provides a positive value as increased generation met an additional 9 aMW of load for customers, priced at market value, the net result is a benefit of $1.7 million when compared to authorized. In total, both the cost variance and generation variance is approximately $1.9 million as shown in Figure No. 10 below.

Figure No. 10 – Colstrip Total Variance

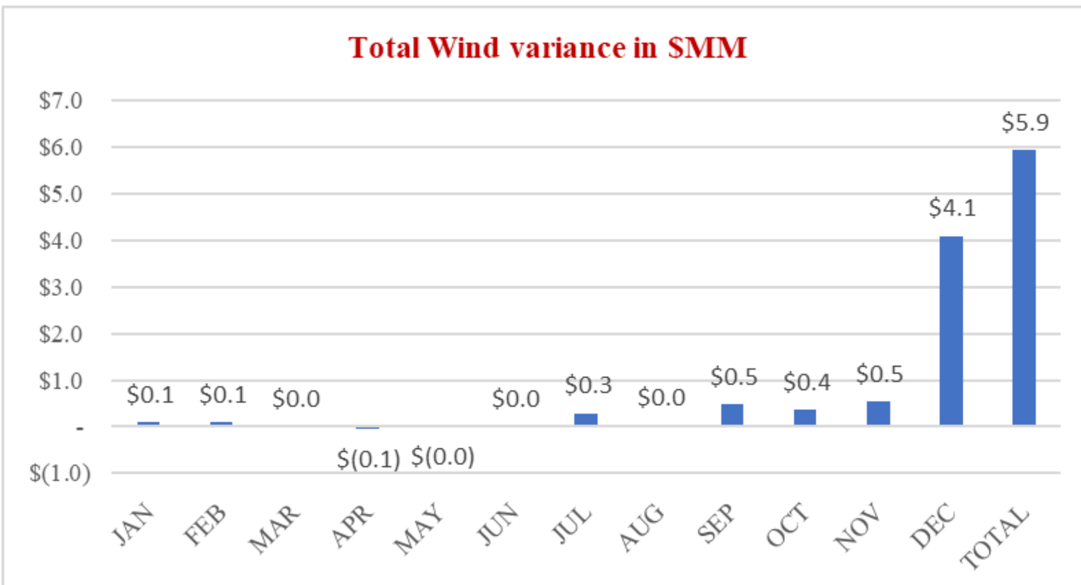


Q. Would you please describe the surcharge variance related to *Item No. 4 Wind Generation* ($5,938,881 surcharge) listed in Table No. 2?

A. Yes. Item No. 4, Wind Generation, is comprised of the Rattlesnake Flat and Palouse Wind PPAs. Palouse Wind generated almost exactly what was authorized, however, Rattlesnake Flat generated 12 aMW less than authorized. This reduction in generation was primarily in December when generation was reduced due to safety concerns which call for the wind blades to stop spinning in periods of extreme weather. The terms of the contract are that Avista only pays for what is generated. As such, a reduced level of generation compared to authorized correspondingly results in a reduced level of expense as compared to authorized by approximately $1.9 million.

The loss of this generation reduced the value of this component of our portfolio of resources. When priced at market prices this resulted in increased generation expense above authorized of approximately $7.8 million. On a net basis, actual expense exceeded authorized in total by approximately $5.9 million with a majority of this increase occurring in the month of December, as illustrated in Figure No. 11 below:

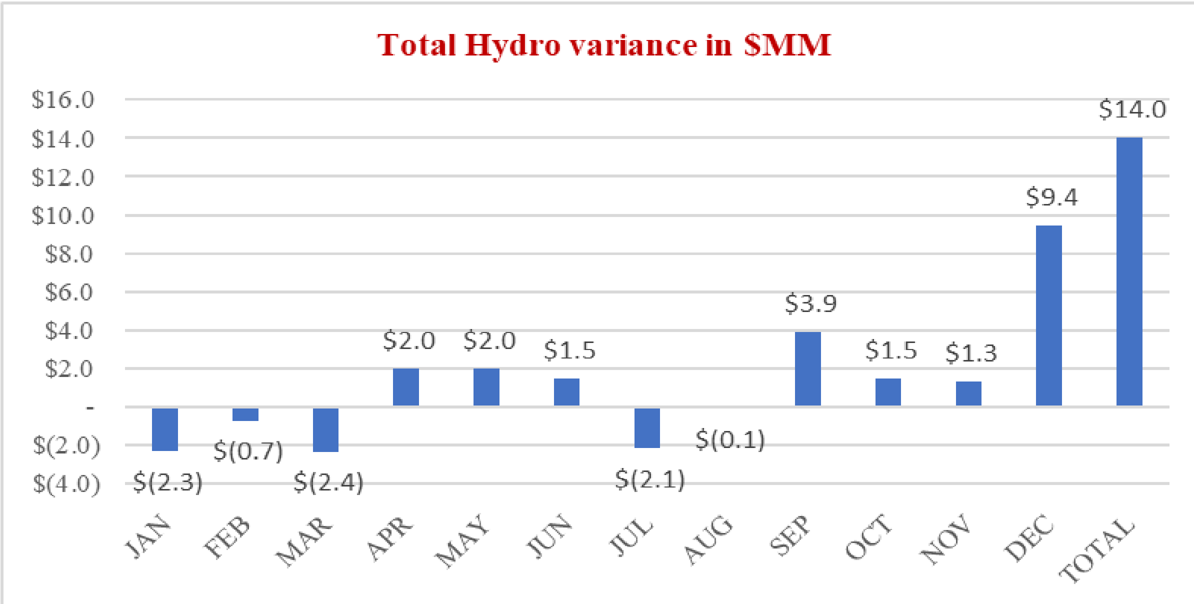
Figure No. 11 – Total Wind Generation Variance



Q. Please now turn to the surcharge variance related to *Item No. 5 Hydroelectric Operations* ($14,023,619 surcharge) listed in Table No. 2?

A. Avista serves load through Avista-owned and operated hydroelectric generation facilities located on the Clark Fork and Spokane Rivers, as well as through contracts with certain facilities located on the Columbia River systems. For 2022, total hydrogeneration was approximately $14 million unfavorable as compared to authorized (14 aMW) as illustrated in Figure No. 12 below.

<u>Figure No. 12 – 2022 Hydroelectric Generation</u>



For 2022, there were several distinct weather patterns which varied by season. In the first quarter, temperatures alternated between days of warmth where snow melted, followed by days of cold where snow froze and stayed in the mountains, followed again by days of warmth, etc. January's average temperature was approximately 13.5 degrees below the 30-year [4]average, while February was only 1 degree below and March was 14 degrees warmer than the 30-year average. For all three months, however, hydroelectric generation was higher than authorized by a total of 373 aMW and associated expense lower than authorized by approximately $5.4 million.

This weather pattern changed beginning in April where the Pacific Northwest had a very cold Spring which kept the water in the mountains and reduced generation as compared to authorized by approximately 163 aMW. As previously mentioned, the summer was extremely hot and runoff was fast, contributing to higher than authorized hydroelectric generation of 77

[4] The average weather used to set the authorized power supply base was a 30-year average.

aMW for the summer months. Finally, the weather pattern flipped once again to extreme levels towards the end of the year in November and December. Temperatures were too cold for the snowpack to melt, resulting in lower than authorized hydroelectric generation for the fourth quarter of 116 aMW. All these higher and lower seasonal variances net to 14 aMW less hydro generation than authorized for the year. The timing associated with these volumes, in combination with market prices at those times – either higher or lower – is the basis for this generation variance.

The Company has contracts with three Public Utility Districts (PUD) for the Mid-Columbia Dams including Grant County PUD, Chelan PUD and Douglas PUD. In 2022, Grant County's Meaningful Priority Contract was higher than authorized by approximately $6.0 million. Each year the price associated with this contract is set based on a market "auction" and the results of that auction are passed back to all Meaningful Priority Contract participants. The value of this contract provides Avista with much needed hydro flexibility and capacity and is a valuable part of its overall portfolio.

Q. Returning to Table No. 2, would you please describe the variance related to *Item No. 6 Other* ($3,007,187 surcharge)?

A. Yes. Item No. 6, Other, is comprised of variances related to variable natural gas pipeline transportation contract expense, transmission expense, the Lancaster PPA, and miscellaneous small charges. The primary components are as follows:

- Lancaster Power Purchase Agreement - $322,000 surcharge. The Lancaster PPA includes a variable portion and a fixed portion intended to cover Capital and Operation & Maintenance (O&M) costs. These O&M costs vary year over year dependent upon planned operations.

- Transmission Wheeling Expense - $1,919,000 surcharge. Transmission wheeling is primarily comprised of Bonneville Power Administration (BPA) Point to Point transmission for CS2 and Lancaster. The increase in expense is primarily related to BPA general rate increases which occur every two years.

- Miscellaneous - $447,187 surcharge. This category is comprised of expenses such as CAISO fees, broker fees, etc.

- Natural Gas Transportation Contracts - $319,000 surcharge. This category reflects the impact of increases in transportation contracts for the upstream Canadian pipelines. These pipelines have annual rated adjustments. In addition are impacted by currency exchange rate differences.

Q. Would you please describe the variance related to *Item No. 7 Net Transmission Revenue* ($5,583,953 rebate) listed in Table No. 2?

A. Transmission revenue was higher than the authorized level primarily from higher than normal short-term and non-firm use of Avista's transmission system in 2022. Higher revenue also resulted from Avista's transmission rate increase which was approved by FERC and became effective October 1, 2021. Avista's point-to-point rates went up 37% and its Annual Transmission Revenue Requirement (which applies to BPA Network Service) rose 53%.

Q. Please describe the impacts of the line No. 9 *Retail Revenue Credit* ($3,617,872 rebate) on line 9 of Table No. 2.

A. The retail revenue credit represents the average power supply cost on a MWh basis. This rate is based on the authorized level of power supply costs as approved in the Company's most recent general rate case. From January 1 through December 21, 2022, this rate was $13.00 per MWh as approved in Docket UE-200900 et. al., and effective December 21, 2022, the rate was reduced to $12.53 as approved in Docket UE-220053 et. al. This rate is intended to offset the volume variance associated with the authorized level of costs.

Q. Would you please describe the variance related to *__Item No. 10 Load Variance__* ($41,886,723 surcharge) listed in Table No. 2?

A. Yes. Item No. 10, Load Variance, was higher than authorized by 57 aMW for the year, resulting in $41.9 million in additional expense as compared to authorized. This additional load variance is reallocated in the variance analysis to generation which contributed to meeting load. For purposes of this variance analysis, the additional load is valued at the market price.

Q. Are there any other factors which affected the ERM Deferral for 2022?

A. Yes. In 2022, the Company tracked the revenues and expenses associated with the Solar Select Program approved by the Commission in Docket UE-180102. The net margin associated with this Program was approximately $1,154,956 in the rebate direction. The primary contributor to this variance was high prices during periods of time when loads were also higher than the levels assumed within the tariff filing. The months particularly impacts were July-September when prices were particularly high as previously mentioned in my testimony. The generation and prices during those months alone contributed to approximately $635,000 of the overall $1,154,956 total benefit. The margin from the Solar Select Program flows through to customers outside of the ERM process at 100%.

__V. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2022__

Q. Please provide a brief description of new long-term contracts that the Company executed during 2022.

A. The Company entered into one long term Power Purchase Agreement with Columbia Basin Hydropower. The agreement is a 23-year supply deal in total with deliveries to Avista starting in 2023 and concluding in 2030. CBHP's projects represent approximately 145 MWs of hydroelectric capacity from seven facilities throughout central Washington. The generation is provided during spring, summer and fall based on irrigation use throughout the Columbia Basin, as shown in Table No. 4.

Table No. 4 – Columbia Basin Hydro Power

Project	3/1/2023	5/1/2023	1/1/2025	3/1/2025	10/1/2025	1/1/2027	9/1/2030
Russell D. Smith	6.1	6.1	6.1	6.1	6.1	6.1	6.1
EBC 4.6		2.2	2.2	2.2	2.2	2.2	2.2
Summer Falls			92.0	92.0	92.0	92.0	92.0
PEC 66.0				2.4	2.4	2.4	2.4
Quincy Chute					9.4	9.4	9.4
Main Canal						26.0	26.0
PEC Headworks							6.5
Total	6.10	8.30	100.30	102.70	112.10	138.10	144.60

In addition, the Company executed two PURPA agreement renewals with the City of Spokane and one with Deep Creek LLC. The City of Spokane's Upriver Dam PURPA contract term starts January 1, 2023 and terminates on December 31, 2037, with a delivered net output of 17.7 MW. The second City of Spokane contract is for the Waste to Energy facility also effective January 1, 2023 and terminating on December 31, 2037. The total amount of power for this contract is approximately 26 MW. Finally, Deep Creek LLC renewal begins January 1, 2023, and expires December 31, 2032 for approximately 412 kW.

VI. THERMAL RESOURCE AVAILABILITY

Q. In the 2006 Settlement Agreement in Docket UE-060181 contained several provisions for adjustments to the ERM. There were two specific requirements applicable to this filing – the first is the treatment of major plant outages and the second is regarding

long term power supply contracts. Please describe how Avista is complying with the requirements regarding the first item.

A. The Settlement stipulation contained an agreement regarding the recovery of fixed costs associated with Kettle Falls, Colstrip Units 3 and 4, and Coyote Springs II when the plants fail to meet a 70% availability factor during the ERM review period. As reflected in Table No. 5 below, no plant failed to meet a 70% availability factor.

<u>Table No. 5 - 2022 Thermal Resource Availability</u>

Thermal Resource Availability		
Kettle Falls	Colstrip 3 & 4	Coyote Springs II
88.32%	92.14%	88.40%

Q. Are any long-term contracts subject to the limitation for inclusion in the ERM that was part of the settlement in Docket UE-060181?

A. No. The 2006 Settlement Agreement in Docket No. UE-060181 regarding the continuation of the ERM included limitations on cost recovery for new or renewed contracts that are greater than 50 MW and have more than a two-year term. No new long-term contracts that were in effect during the 2022 review period are subject to limitations on cost recovery.

VII. SUPPORTING DOCUMENTATION

Q. Please provide a brief overview of the documentation provided by the Company in this filing.

A. The Company maintains several documents that record relevant factors considered at the time of a transaction. The following is a list of documents that are maintained and that have been provided in electronic format with this filing:

- Natural Gas/Electric Transaction Records: These documents record the key details of the price, terms, and conditions of a transaction. As part of Avista's workpapers accompanying this filing the Company has provided a confidential worksheet showing each natural gas and electric term (balance of the month or longer) transaction during 2022, including all key transaction details such as trade date, delivery period, price, volume, and counterparty. Additional information can be provided, upon request, for any of these transactions.

- Position Reports: These daily reports provide a summary of transactions and plant generation and the Company's net average system position in future periods. The Daily Position Reports also contain forward electric and natural gas prices.

- 2022 Variance Analysis. This Excel file provides detailed calculations for hydro and thermal authorized and actual values by month. In addition, the "Summary" tab allows the user to modify his/her selection by choosing the appropriate resource type (labeled as "1", "2", etc.). A monthly table is then populated to illustrate aMW, cost variance, generation variance, and total variance.

- ERM Variance Workpapers. This excel file is very similar to the 2022 Variance Analysis file but provides additional detail on a monthly basis.

VIII. OVERVIEW OF DEFERRAL CALCULATIONS

Q. Please provide an overview of the deferral calculation methodology.

A. Energy cost deferrals under the ERM are calculated each month by subtracting base net power supply expense from actual net power supply expense to determine the change in net power supply expense. The base levels for 2022 result from the power supply revenues and expenses approved by the Commission in Docket No. UE-200900, et. al. for the January – December 21, 2022 timeframe and Docket No. UE-220053, et. al. for the December 22 – December 31 timeframe. The methodology compares the actual and base amounts each month in FERC accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel) and 447 (Sales for Resale) to compute the change in power supply expense. These four FERC accounts comprise the Company's major power supply cost/revenue accounts. The ERM also includes costs or revenues in Accounts 565 (transmission expense), 456 (third-party transmission revenue), and broker fees (557).

In addition, actual expense and revenue for natural gas not burned is included as natural gas sale revenue under Account 456 (revenue) and purchase expense under Account 557 (expense). This would include benefits and costs related to optimizing the value of natural gas turbines and power supply's natural gas transportation contracts. All expenses are recorded in accordance with Generally Accepted Accounting Principles and FERC's Uniform System of Accounts.

The total change in net expense under the ERM is multiplied by Washington's share of the Production/Transmission Ratio (PT Ratio) approved in association with base net power supply expense. Change in Washington retail sales is then multiplied by the Retail Revenue Adjustment Rate and added or subtracted from the change in power supply expense to calculate the total power cost change. The total power cost change is accumulated during the calendar year until the dead band of $4.0 million is reached. 50 percent of power cost increases, or 75 percent of the decreases, between $4.0 million and $10.0 million, and 90 percent of the power cost increases or decreases in excess of $10.0 million are recorded as the power cost deferrals and added to the power cost deferral-balancing account, as illustrated in Table No. 6 below:

Table No. 6 - ERM Sharing Bands

Annual Power supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Q. Please explain how the retail revenue adjustment is determined in the ERM.

A. The ERM includes a retail revenue adjustment to reflect the change in power production and transmission expense recovered through base retail revenues, related to changes in retail load. The retail revenue adjustment rate calculation is based on the average rate of the power supply expense related FERC accounts included in the Company's general rate case. The retail revenue adjustment January 1 through December 21, 2022 was $13.00/MWh , and $12.53 for December 22, 2022 through December 31, 2022.

The monthly retail revenue adjustment in the ERM is computed by multiplying the retail revenue adjustment rate times the difference between actual and authorized monthly retail Megawatt-hour sales. If actual Megawatt-hour sales are greater than base, the retail revenue adjustment will result in a credit to the ERM deferral (reduces power supply costs). If actual Megawatt-hour sales are less than base, the retail revenue adjustment will result in a debit to the ERM deferral (increases power supply costs).

Q. What ERM calculations are provided to the Commission and other parties?

A. The Company provides to the Commission and other parties a monthly power cost deferral report showing, among other things, the calculation of the monthly deferral amount, the actual power supply expenses and revenues for the month, and the retail revenue adjustment. These pages from the December 2022 deferral report are included as Exh. AMB-2. The December 2022 deferral report pages show all of the months, January through December of 2022. Please note these pages represent a subset of the December 2022 Report provided as Exh. AMB-2.

Q. Does that conclude your pre-filed direct testimony?

A. Yes.