Exh. SJK-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-24____

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 Energy Recovery Mechanism (ERM) and provides a summary of the factors contributing to the power cost deferrals during the 2023 calendar year review period. I provide an overview of the documentation the Company has provided in workpapers, which the Company agreed to provide in the ERM Settlement Stipulation approved and adopted in Docket 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 Exh. SJK-2 which contains five pages from the Company's December 2023 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 2023 through December 2023. 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 2023?**

A. For the 2023 calendar year, <u>actual</u> net power costs were more than <u>authorized</u> for the Washington jurisdiction by $23,910,731 (excluding interest). The deferral in the customer surcharge direction for 2023, amounted to $15,519,489. Pursuant to the mechanics of the ERM, the Company absorbed $8,391,242 of increased power costs in 2023.

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

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

## II. OVERVIEW AND HISTORY OF THE 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.

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 2022 calendar year was filed March 31, 2023 in Docket UE-230214.

## 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. Numerous variables affect short-term power supply positions and prices. As such, the Company employs an Energy Resources Risk Policy ("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 Resources 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 always maintained. It is necessary to buy and sell energy (or financially equivalent derivative transactions) in hourly, daily, balance of the month, monthly, and longer increments, as well as 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 several 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 if it is relevant to term positions. 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 (includes storage).
- 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.
- Optimizing system and off-system resources for inclusion of emission free resources.
- 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 optimize our system around regional diversity.

**Q. Does the Company have an active hedging program?**

A. Yes. The Company employs an Electric Hedging Plan to guide power supply position management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a price diversification approach employing a layering strategy for forward purchases and sales of either natural gas fuel for generation or electric power to approach a generally balanced financial position against expected load as forward periods draw nearer considering time to delivery and market conditions.

The goal of Avista's Electric Hedging plan is to provide reliable electric and natural gas services at a competitive cost for customers while addressing risks inherent to supplying energy and managing energy resources. Energy Resources is responsible to hedge expected electric surpluses and deficits with the goal to optimize its position and impact cost variances. To do this, the Company developed its Power Supply Hedging Plan (PSHP) to guide power supply position management in the short-term period. The PSHP is intended to be dynamic, so it remains responsive to Avista's changing resource portfolio, load profile, forward price changes, prevailing market partners and other external factors.

The Company employs a Power Supply Hedge Requirements Report tool (PSHRR). The PSHRR is an analytic tool to guide power supply hedging decisions in the short-term forward period. 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 judgment or market conditions warrant other actions, no action, or simply a delay in taking action.

The PSHRR will define potential transactions to reduce open positions for each month or quarter over the available time between the current date and future delivery periods. PSHRR transactions are designed to systematically reduce open financial positions for established hedge delivery periods up to “x” months into the future. The PSHRR is designed to recommend forward time periods for hedge transactions based on risk and/or price indicators. Note that natural gas for load hedges are done on a time basis only; risk/price indicators do not affect our gas for load buying frequency and Avista purchases natural gas for load on an incremental, timed basis.

Moreover, the model includes several estimates such as price, estimated load or other obligations, variable energy resource generation, hydroelectric generation based, and long-term contracts. When a change in these values identifies the need for a transaction, the PSHRR shows the forward time periods and the hedge amount in dollars to resolve open financial position. The PSHRR is dynamic based on the best information available each business day. Whenever a hedge transaction is executed (or the equivalent change in net financial position forecast occurs), PSHRR recalculates the financial open positions.

**Q. What are the recommended forward time periods for the hedge transactions?**

A. Avista follows the delivery periods outlined in its Risk Policy. For any given month, known as the Hedge Assessment Month, an assessment of potential hedges would look to the sequential future periods and identify specific timelines and design their strategy based on the resulting blocks. For the most immediate 10 to 12 months, each individual month is addressed individually as monthly blocks. After these monthly blocks, a minimum of four calendar quarters (maximum of six quarters) are addressed in quarterly blocks. One calendar year block (starting a minimum of 19 months in the future) provides the end of the hedge assessment range for the Short-Term horizon.

**Q. How does the Power Supply Hedge Requirements Report Work?**

A. With the forward horizon split into transaction periods as detailed above, the PSHRR is designed to recommend forward time periods for hedge transactions based on risk limits, price indicators and/or time. The model involves several steps that are described below.

The model measures the Open Heat Rate and the Power for Load positions, sums these volumes, and multiplies these sums by forward power prices to produce each forward time period's respective net power position. When a change in forward prices, estimated load, hydro or other reported/forecasted values occurs to create the need for a transaction, PSHRR shows the forward time periods and the hedge amount in dollars to resolve open financial position.

The model also measures the amount of gas necessary to serve forecasted load. This gas is hedged at a paced rate on a periodic basis only. Gas is purchased on an incremental basis over the time periods explained above to fuel thermal plants and subsequently serve electricity load. These forward net positions are managed volumetrically—separately from open heat rate and power for load positions.

Hedge Candidates calculated by PSHRR will include volumes of commodities that will resolve the short or long financial positions while not moving the commodity position further from zero. Commodities could include MID-C Peak Power, MID-C Off-Peak Power, and MALIN Gas, and AECO Gas. The PSHRR is dynamic based on the best information available each business day. Whenever a hedge transition is executed (or the equivalent change in net financial position forecast occurs), PSHRR recalculates the financial and volumetric open positions.

**Q. Does the Company consider inputs outside of the PSHRR in its Power Supply Hedging Plan (PSHP)?**

A. Yes. The PSHP is a guide for transactions that reduce the net surplus or deficit position, but the PSHP is not intended to dictate a strict course of action nor to limit decisions or to replace management judgement. In cases where management either voluntarily or involuntarily makes decisions that deviate from the PSHP, the reasons for deviating from the plan will be documented contemporaneously and reported to the Risk Management Committee (RMC).

**Q. How does the Company communicate its position within the Energy Resources Team?**

A. All changes that affect the Short-Term electric position are reflected each business day in an electric position report. The daily report depicts estimated loads and obligations, estimated resources, and estimated open positions for power for each month within the first 30 to 41 months in the term horizon. The daily position report will also show current position status compared to the PSHP. The daily position reports for calendar 2023 have been included within the Company's confidential workpapers.

## IV. 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 authorized base level of net power supply expense ("authorized") from actual net power supply expense to determine the change in net power supply expense. The authorized levels for 2023 result from the power supply revenues and expenses approved by the Commission in Docket UE-220053, et. al. for the calendar year 2023 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 capturing the value associated with power supply's natural gas transportation contracts when they are not needed to satisfy electric retail load needs. 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. For this period, that ratio results in a 65.54 percent allocation to Washington. 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. If total power cost changes exceed $4.0 million, then 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. 1 below:

**Table No. 1 - 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 for January 1 through December 31, 2023 was $12.53/MWh.

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 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 2023 deferral report are included as Exh. SJK-2. The December 2023 deferral report pages show all the months, January through December of 2023.

## V. 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 2023?**

A. During 2023, actual net power costs were higher than authorized power supply costs for the Washington jurisdiction by $23,910,731 (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 $23,910,731. Of this total, the Company absorbed $8,391,242 and a deferral was recorded in the amount of $15,519,489 (excluding interest), as shown in Table No. 2.[1]

**Table No. 2 – 2023 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% | $ 13,910,731 | $ 1,391,242 | $ 12,519,489 |
| | $ 23,910,731 | $ 8,391,242 | $ 15,519,489 |

**Q. What causes a variance between Actual Power Supply Costs and Authorized Power Supply Costs?**

A. A variance occurs when the level of actual expense differs from the authorized level of power supply expense. The authorized level of power supply expense is intended to be a forecast of anticipated expenses based on the expected market conditions, generation asset dispatch and costs associated with energy supply. The authorized level of power supply costs is established in a general rate case well ahead of the year in which they are applied. For Avista, 2023 authorized expense levels were based on data available in 2021 and established in Docket UE-220053. The older the authorized base, the less likely the authorized base will accurately reflect the actual market conditions that are experienced in the applicable year. This leads to more opportunity for a variance between authorized and actual expenses. While the authorized base is intended to capture all future assumptions of energy costs, it is unable to account for the unknown variables that are experienced both by Avista's owned assets and external market conditions.

[1] As discussed by Ms. Schultz, the total customer current year deferral surcharge (Account 186280) per the general ledger (GL) as of December 31, 2023 was $15,825,797, which is comprised of $15,519,489 current year deferral, plus $306,308 in interest. In 2023, the total customer current year deferral surcharge was understated in the GL by approximately $1,725 (customer deferral of $1,688, plus $37 in interest) related to broker fees. In January 2024, the Company recorded an adjustment to correct the GL for this amount.

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

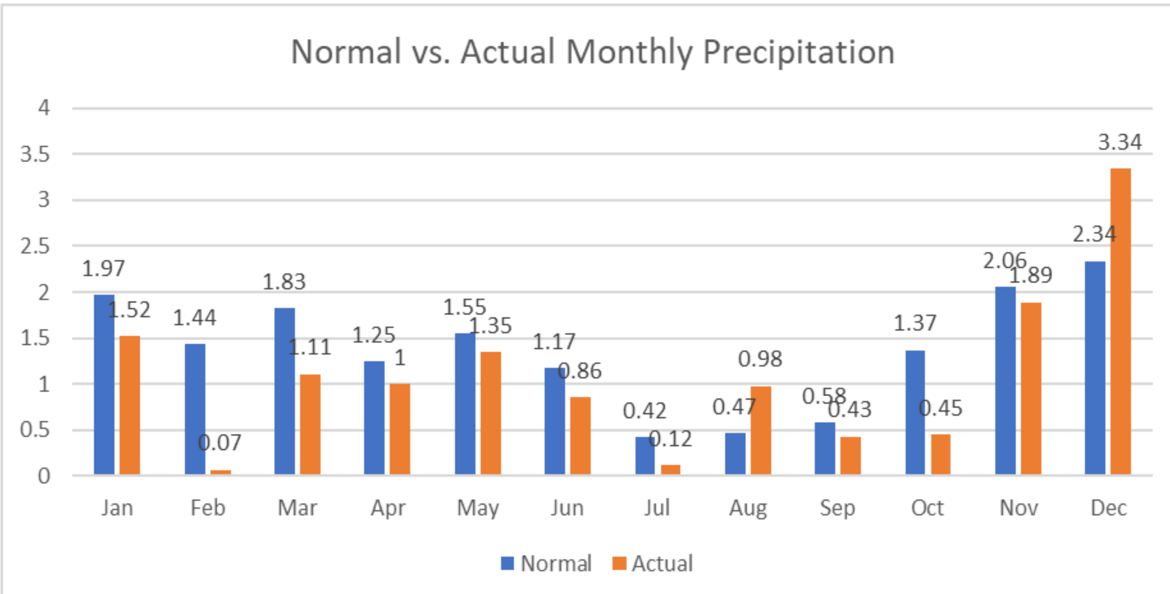
A. The increase in power supply expense is attributed to the combination of factors including the variability of available power from various generation resources, changes in the in overall demand of energy from customers, and external market factors such as energy pricing and other costs associated with providing power. For 2023, the most prominent factors that impacted the ERM were attributed to: (1) lower than anticipated hydroelectric generation from both Avista-owned and contracted-for resources; and (2) the region experiencing significant weather variations which increased loads particularly during times where prices were high.

**Q. Please describe the conditions that impacted hydroelectric generation during 2023.**

A. The primary factors which impacted hydroelectric generation for 2023 were lower than normal precipitation for the majority of year, in combination with temperature variations which impacted snowpack and runoff. In total, Avista's combined hydroelectric generation from the Clark Fork, Mid-Columbia and Spokane River system was significantly lower than average, totaling an average of 413 aMW for the year compared to an authorized estimate of 535 aMW. This marks one of the lowest hydroelectric generation levels in the past 35 years. On the Clark Fork alone, generation was 242 aMW, a staggering 72 aMW less than anticipated in authorized. In the previous 35 years, only 2001 and 1994 had generation levels lower than this amount.

Average precipitation for the majority of the year was lower than anticipated, materially reducing the availability of supply required to replenish water reserves required for hydroelectric generation. The Spokane region went 10 consecutive months with below normal precipitation for the 2022-2023 water year, which began in October 2022.[2] Figure No. 1 below illustrates the monthly normal vs actual levels of precipitation (rainfall) in Spokane during 2023.

**Figure No. 1 – 2023 Monthly Precipitation at Spokane (inches)**



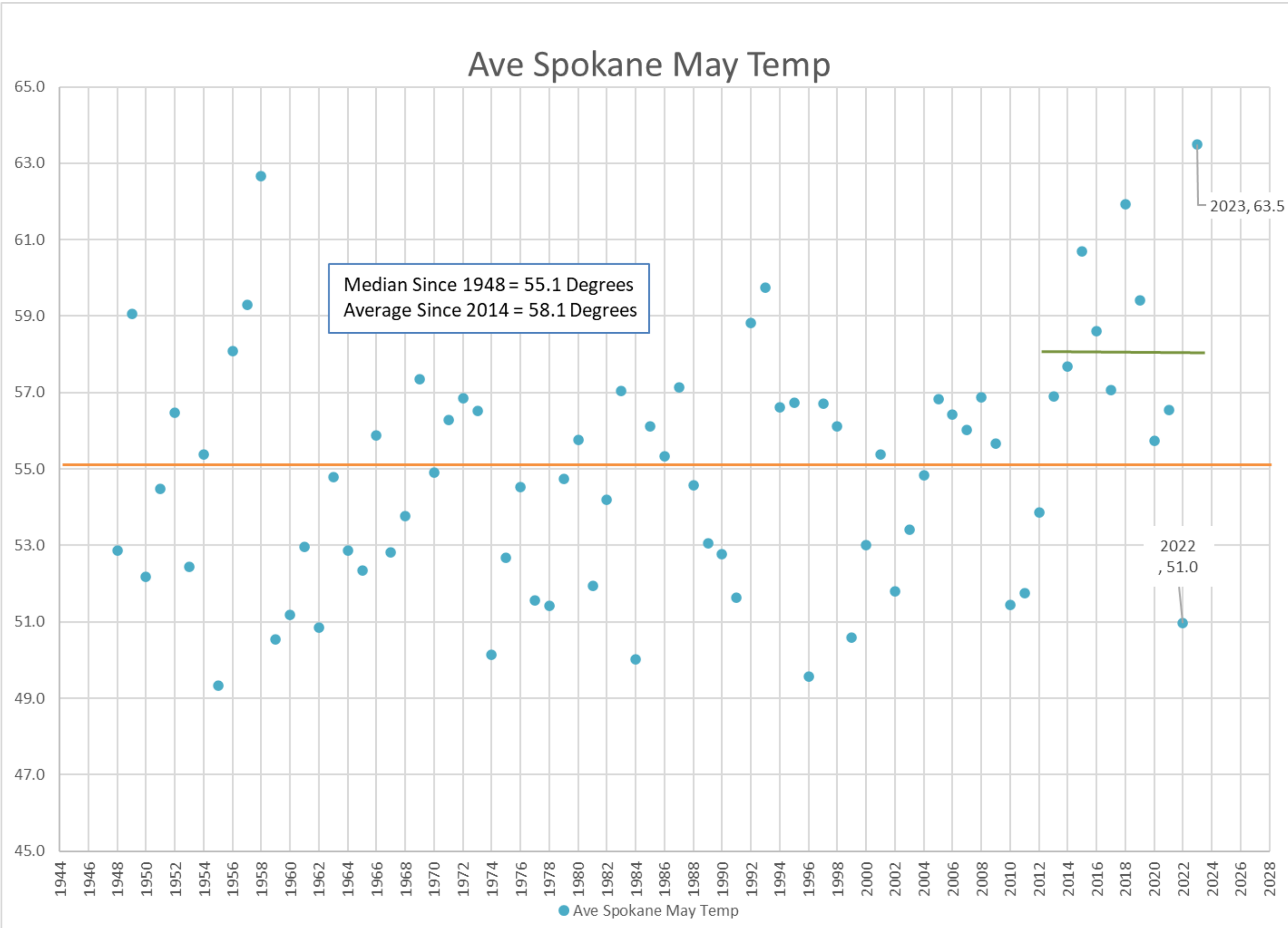

In spite of lower-than-normal precipitation, the snow-water equivalent[3] of the mountain snowpack was near or exceeded expectations through mid-April 2023. The Spokane River drainage was approximately 111% of normal, and the Clark Fork drainage was approximately at 92% of normal. Colder than normal temperatures, however, prevented snowmelt and reduced river inflows resulting in reduced hydroelectric generation particularly in March and April.

In the month of May, colder than normal temperatures rapidly increased to higher-than-normal, resulting in an unprecedented rapid snowmelt, depleting snowpack reserves almost entirely. The average temperature in May 2023 was 63.5 degrees, which was significantly

[2] Represents the seasonal accumulation of water used in hydroelectric generation.
[3] Snow-water equivalency represents the amount of moisture contained within snowpack. It is a measurement of how much water is contained in one inch of snow.

higher than the prior year (51 degrees) and well above the running average (55 degrees). Figure No. 2 below illustrates the historic average temperatures in the month of May.

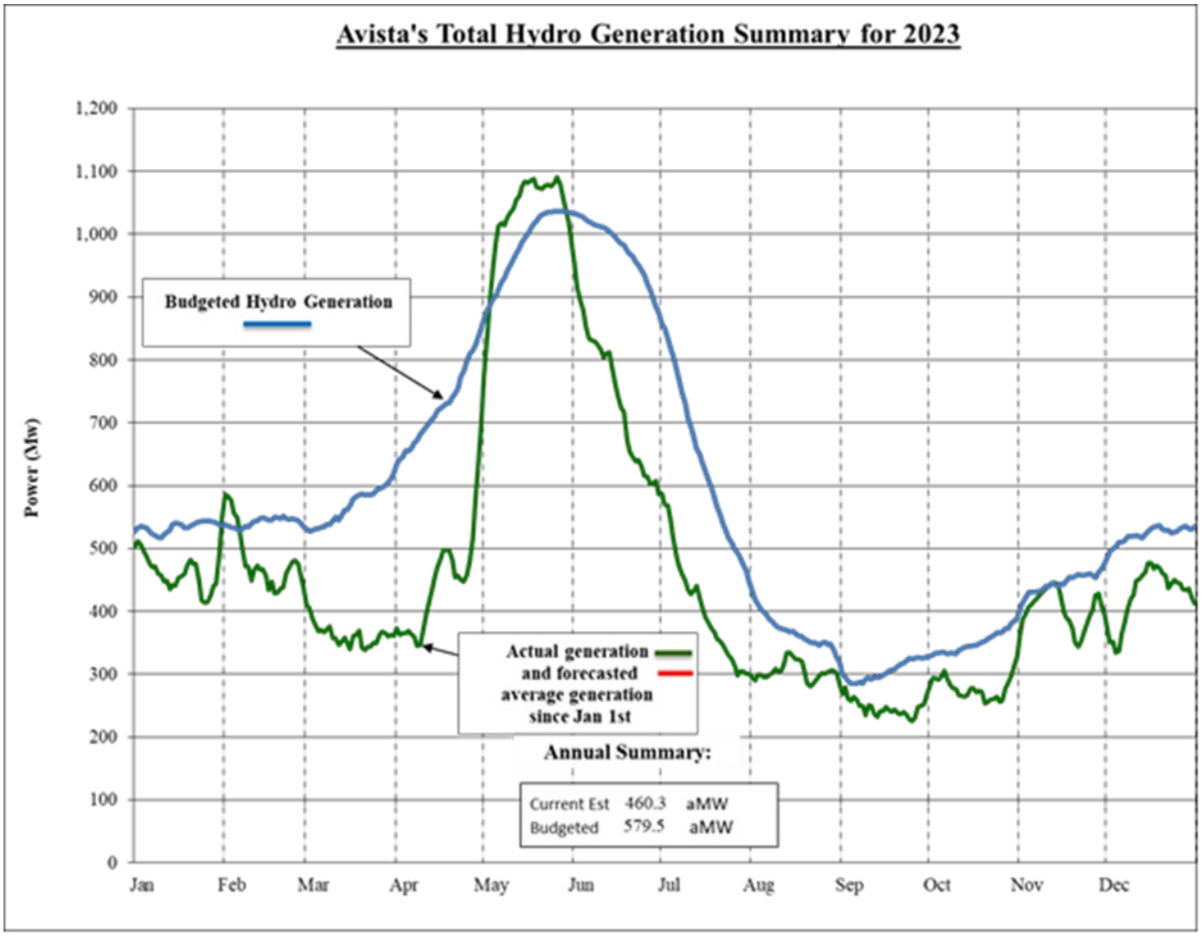
**<u>Figure No. 2 – Historic Average Spokane Temperatures May 2023</u>**




The impact of this rapid depletion significantly reduced the availability of hydroelectric generation for the remainder of 2023. Figure No. 3 illustrates this change in relation to the authorized[4] level of hydroelectric generation.

[4] Figure No. 3 is based on average 30-year hydroelectric generation, whereas authorized is based on 80-year median. The chart is intended to be illustrative of the magnitude of a change; not for actual analysis.

**<u>Figure No. 3 – Total Hydro Generation Summary 2023</u>**



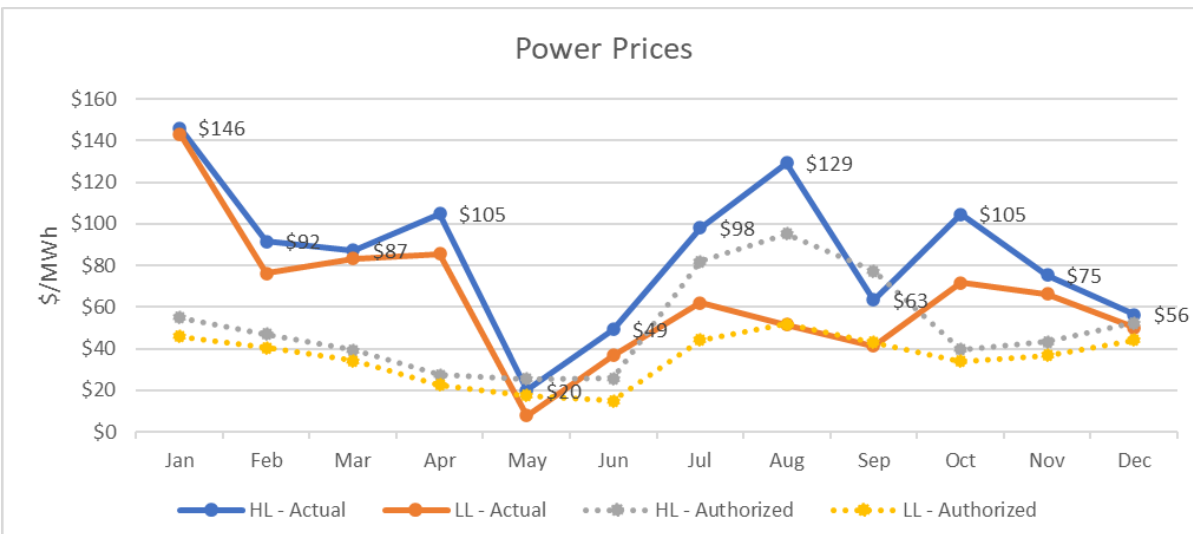

This reduced hydroelectric production was a region-wide condition and was not unique to Avista. According to the U.S. Energy Information Administration[5], hydropower generation in the Northwest was 24% lower in the first half of 2023 as compared to the previous year. The lack of reduced hydroelectric production was a key contributor to increases in both electric and natural gas market prices.

**Q. How were prices impacted by these conditions and what was the impact to the ERM, particularly in months where load was the highest?**

[5] https://www.eia.gov/todayinenergy/detail.php?id=60522&src=email

A. The region experienced extremely high power and natural gas prices beginning at the tail end of 2022. Power prices rose dramatically in December 2022 and remained almost three times as high in January 2023 than they were in January of 2022.[6] The conditions described in the Company's 2023 annual ERM filing relative to December 2022 remained throughout the entire winter until April 2023. As an example, for the first two months of 2023, the Mid-C electric market heavy load (HL) and light load (LL) average pricing was approximately $90-$100/MWh higher than authorized. Figure No. 4 below illustrates the monthly Mid-C pricing for 2023, showing both the actual power prices along with the authorized pricing for high load and low load periods.

**<u>Figure No. 4 – Power Prices in 2023 as Compared to Authorized</u>**




As illustrated in Figure No. 5, natural gas prices were also significantly higher than the previous year in response to increased demand for natural gas customers as a result of below average temperatures, transportation constraints on pipelines that served California markets,

[6] https://www.newsdata.com/clearing_up/price_report/low-paci c-northwest-hydro-boosts-western-powerprices/article_978407f8-98f7-11ed-a6ad-a3f69afebd26.html

low gas storage levels across the West and significant increases in natural gas burned for generation as electric loads were also higher than estimated.

**<u>Figure No. 5 – Daily Natural Gas Prices</u>**

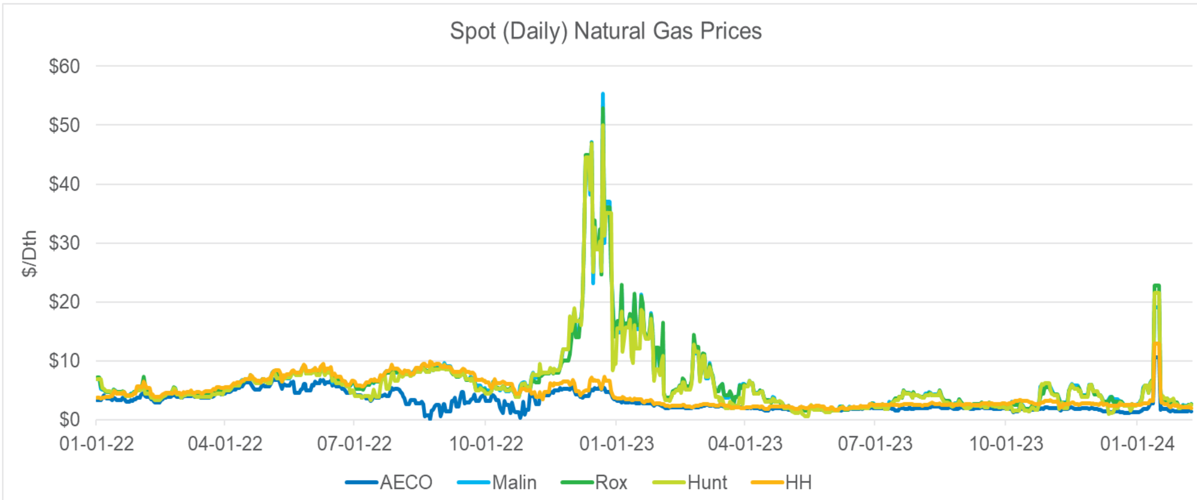
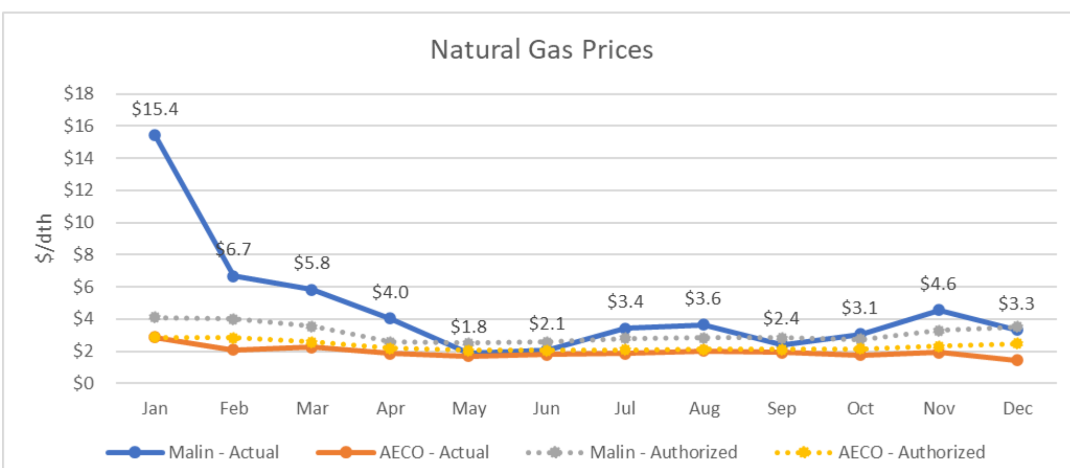



Figure No. 6 below provides an annual illustration of the natural gas prices at AECO and Malin. As compared to authorized, gas prices were almost triple the authorized amount for Malin and approximately 25% higher than authorized for AECO in January. Natural gas prices reached a high of $15.40/dth during January, a month in which the region also experienced continued high demand.

**<u>Figure No. 6 – Natural Gas Prices in 2023 as Compared to Authorized</u>**

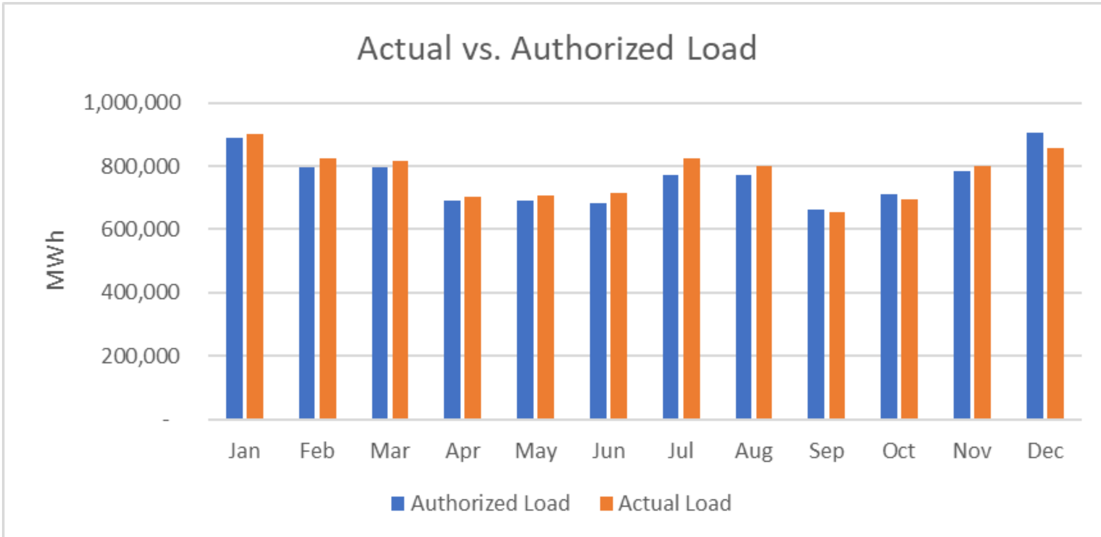


**Q. What demand conditions were in effect during the year that played a role in the ERM variance?**

A. As previously mentioned, it is understood that customer loads will vary month-to-month and season-to-season due to a variety of factors. For 2023, customer loads exceeded expectations every month from January through August. There is a high correlation between customer loads and temperatures and this year was no exception. From January until almost the end of April, temperatures were lower than normal resulting in higher demand for electricity. Beginning at the end of April, this weather pattern abruptly changed from colder-than-normal to hotter-than-normal and continued in this pattern throughout the summer pushing loads up as the demand for air conditioning increased.

This increase in demand is met through the use of either Company-owned or contracted-for generating resources such as natural gas or wind and solar, or through market purchases. Several methods are utilized to ensure the most economic mix of resources are utilized to meet this increased load. Nevertheless, the impact of higher loads in periods when demand is constrained due to hydroelectric conditions puts increasing upward pressure in prices resulting in higher increased overall power supply expenses to meet this increased load. For the year, actual load exceeded the authorized level by approximately 17 aMW. The monthly shape of these variances is provided in Figure No. 7 below:

**<u>Figure No. 7 – 2023 Monthly Load Variance Compared to Authorized</u>**




**Q. How was the Company able to meet load requirements given the lower-than normal hydro availability?**

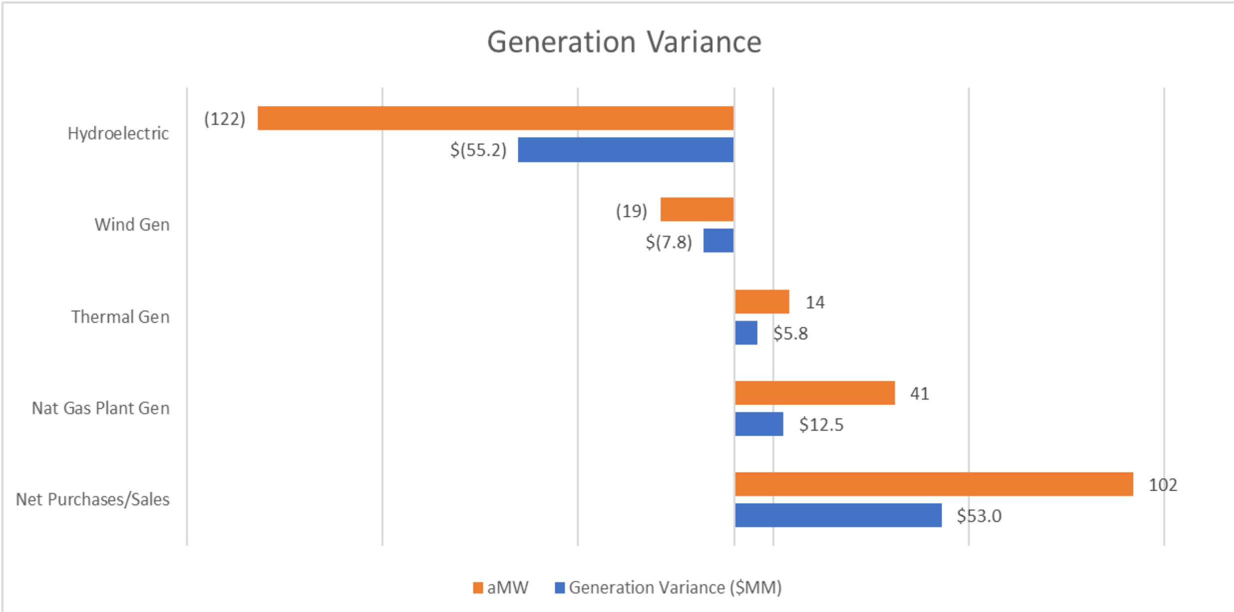
A. The Company relied on a combination of owned and contracted resources. The variances generated by each resource component provide the basis for the variance analysis in this testimony. Overall customer load remained consistent with a small variance between authorized load and actual load; the resources that serve that load, however, resulted in a significant variance in cost. Dependent upon economics and resource availability, the Company utilized a mix of resources and market purchases to meet the demands of these additional loads. This is captured in the generation variance.

**Q. Did the Company create a generation variance analysis?**

A. Yes. 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. 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 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.

Figure No. 8 below illustrates the generation variances, in average megawatts of energy and in total dollars (in millions), across the various resources available to Avista. Because of the decrease in hydroelectric generation as described above, a larger ratio of the Company's overall load was served by other generation types. These include thermal generation, natural gas generation and through purchases of energy represented by "Net Purchases/Sales." Note that the annual variance does not fully capture the impact of individual months where a high/low cost of energy is coupled with higher/lower customer load, but rather is intended to illustrate the overall impact of lower hydroelectric generation and the resulting resources needed to meet customer demand.

**Figure No. 8 – Generation Variance between Resource Types during 2023**




## VI. OVERVIEW OF VARIANCE COMPONENTS

**Q. Please provide an overview of each component of the variance analysis.**

A. Table No. 3 below provides the primary components of the variance analysis including the "Cost Variance" and "Generation Variance". These two categories of variance make up the total amount of variance within the ERM and are further described below. Please note in all variance tables, a positive number represents unfavorable; a negative number indicates favorable.

**Table No. 3 – 2023 Variance Factors (+) Unfavorable (-) Favorable**

| Washington Share | | | | |
|---|---|---|---|---|
| | | Cost Variance | Generation Variance | Total Variance |
| 1 | Net Purchases/Sales | $ (27,549,912) | $ (52,985,231) | $ (80,535,143) |
| 2 | Natural Gas Plant Generation | $ 38,911,991 | $ (12,487,192) | $ 26,424,798 |
| 3 | Thermal Generation | $ 7,077,844 | $ (5,797,046) | $ 1,280,798 |
| 4 | Wind Generation | $ (4,122,685) | $ 7,821,892 | $ 3,699,206 |
| 5 | Hydroelectric Operations | $ 9,967,987 | $ 55,211,111 | $ 65,179,098 |
| 6 | Other | $ 3,175,307 | $ - | $ 3,175,307 |
| 7 | Net Transmission Revenue | $ (2,256,205) | $ - | $ (2,256,205) |
| | Subtotal | $ 25,204,326 | $ (8,236,467) | $ 16,967,859 |
| 8 | Retail Revenue Rate Adjustment | $ (1,293,595) | $ - | $ (1,293,595) |
| 9 | Load Variance | $ - | $ 8,236,467 | $ 8,236,467 |
| 10 | Total Variance | $ 23,910,731 | $ (0) | $ 23,910,731 |

For purposes of this variance analysis, workpapers provided by Avista differentiate between the "cost variance" and "generation variance." The cost variance is a more traditional, accounting depiction representing the price/quantity variance[7] comparing actual values to authorized values as recorded to the general ledger. The "generation variance"[8] is an economic look which represents the value each resource contributed towards meeting customer load requirements. This portion of the variance is to illustrate the value (or lost value) of the overall portfolio of resources utilized to serve load. The purpose of this portion of the variance is to adjust for volume fluctuations and provide insight into how the Company managed its resources in response to the market conditions during 2023. Each individual line item from Table No. 3 is further discussed below.

***Item No. 1: Change in Net Power Purchase Expense ($80,535,143 lower than authorized base).*** . 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. The Company

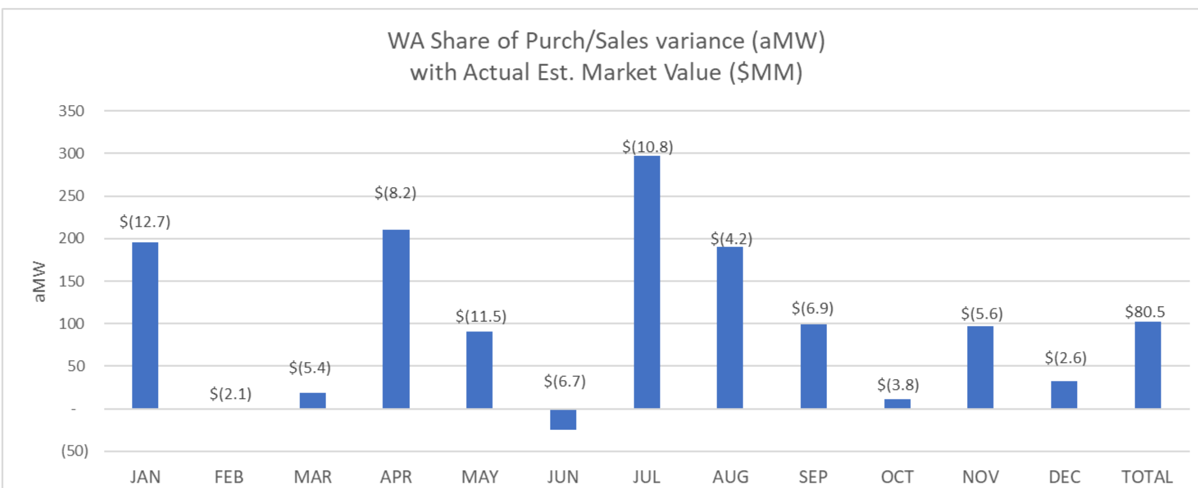
[7] The cost variance can be further broken down by price variance (change in price multiplied by actual price) and volume variance (change in volume times authorized price).

[8] 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.

considers several factors including economics, load requirements, and hydro conditions when evaluating the benefits of off-system sales. For 2023, purchases exceeded sales, netting to 102 aMW more purchases than estimated in authorized. While net purchase expense was above authorized on a volumetric basis, net sales revenue far exceeded this due to lower prices than in authorized, resulting in net purchases lower than authorized by $27.5 million. The Company was able to capture the benefit of favorable economic conditions (including pricing) in periods of time when resources were available after load was served. Price played a key role in this variance, as power prices exceeded authorized in 10 of 12 months on a heavy load basis and 8 out of 10 on a light load basis (See Figure 4).

On an economic look, as reflected in the generation variance, the value of these transactions is even more significant. In effect, these transactions were able to ensure not only customer load was met in a poor hydro year, but also that resources were fully optimized, when possible, to reduce customer impacts. This generation variance represents an additional $53.0 million lower net purchases than in authorized. On a total basis, net purchases were lower than authorized by $80.5 million ($27.5 million cost + $53.0 million generation).

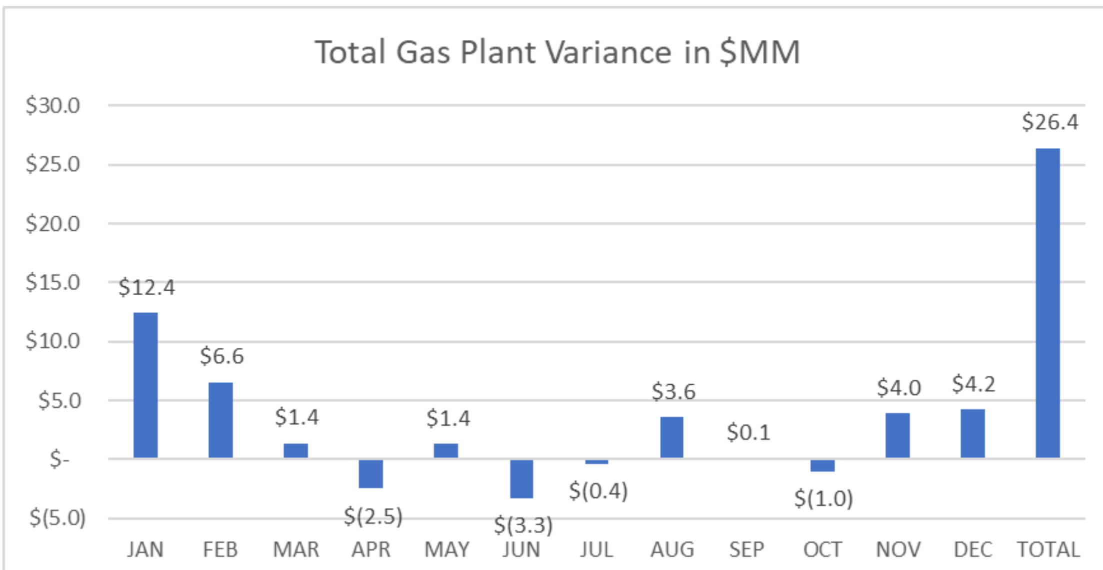
**<u>Figure No. 9 – Net Purchase/Sale Generation Variance aMW and Cost</u>**




***<u>Item No. 2: Change in Natural Gas Generation ($26,424,798 higher than authorized base)</u>.*** This item is primarily comprised of Avista's Coyote Springs II (CS2) generating station, as well as a Power Purchase Agreement (PPA) associated with Lancaster. Also included in Avista's overall natural gas generation portfolio, categorized as "Other CT", are Boulder Park, Rathdrum, Kettle Falls CT, and Northeast Combustion Turbine. For the review period, natural gas generation was higher than anticipated in the authorized base forecast by 41 aMW. Generation at CS2 contributed the most to this variance, accounting for 17 aMW of the total. On a cost basis, natural gas generation was approximately $38.9 million above what was forecast in the authorized base, due to the increase in generation at natural gas prices which were higher in actuals than in authorized base level in almost all months of the year. As illustrated in Figure No. 6, the actual cost of natural gas in the first quarter was higher than authorized with pricing as high as $15.40/dth from Malin compared to $4.10/dth authorized.

However, these natural gas resources were particularly valuable in meeting customer loads with lower hydroelectric generation available in late Spring through the remainder of the year. To demonstrate this value, the generation variance removes the impact of the volume variance by approximately $12.5 million. By removing this variance, the analysis more accurately reflects the impact of only this increase in price, resulting in a total expense variance of approximately $26.4 million, after sharing. Figure No. 10 below illustrates the monthly and annual variance associated with natural gas plant costs.

**<u>Figure No. 10 – Natural Gas Plant Variance</u>**




***<u>Item No. 3: Change in Thermal Generation ($1,280,798 higher than authorized base)</u>***. Thermal operations is comprised of the Colstrip Generating Station (Units 3 and 4) and the Kettle Falls Generating Station. For both plants combined, total expense exceeded authorized by approximately $1.3 million, as shown in Table No. 4 below.

**Table No. 4 – Thermal Generation Reconciliation**

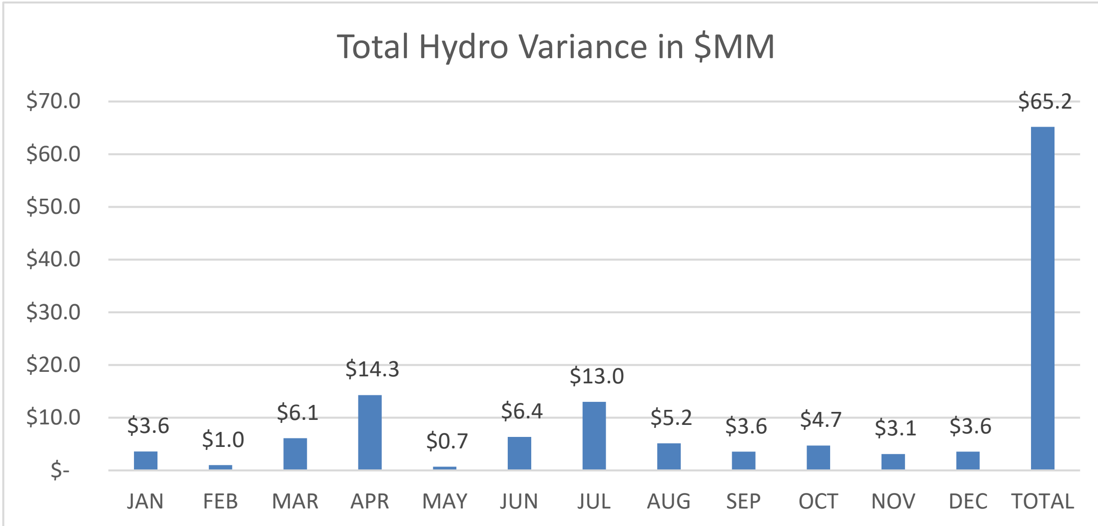
| Thermal Generation | | | |
|---|---|---|---|
| | Cost Variance | Generation Variance | Total Variance |
| 1 Kettle Falls | $ 2,314,152 | $ (1,128,160) | $ 1,185,993 |
| 2 Colstrip | $ 4,763,692 | $ (4,668,887) | $ 94,805 |
| 3 Total | $ 7,077,844 | $ (5,797,046) | $ 1,280,798 |

Colstrip generation was very close to authorized with a total variance of $94,805. Likewise, Kettle Falls generation was also close to authorized with a total variance of approximately $1.2M. The cost to generate was higher than authorized due to higher fuel prices as illustrated in the Cost Variance in Table No. 4. For the year, the total variance netted to 14 MW of additional generation above what was included in authorized. The highest levels of generation variance occurring in the June-September months, coincident with the lower hydroelectric generation. The net result was a fuel expense which was higher than authorized by approximately $1.3 million.

***Item No. Item No. 4: Change in Wind Generation ($3,699,206 higher than authorized base)***. Wind generation is comprised of the Rattlesnake Flat and Palouse Wind PPAs. Palouse Wind generated 4 aMW less than authorized and Rattlesnake Flat generated 14 aMW less than authorized. The lower generation occurred in most months throughout the year with July and November seeing the most significant generation variances which were 32.6 aMW and 40.1 aMW respectively less than authorized. 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 $4.1 million (cost variance). 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 $3.7 million.

***Item No. 5: Change in Hydro Generation ($65,179,098 higher than authorized base)***. 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 2023, total hydrogeneration was approximately $65.2 million unfavorable as compared to authorized as illustrated in Figure No. 11 below.

**<u>Figure No. 11 – 2023 Hydroelectric Generation</u>**




For 2023, there were distinct weather patterns which varied by season with the overall impact resulting in a dryer water year. Please see the expanded explanation in Section V for more detail on the 2023 hydro impacts.

Contributing to the cost variance, the Company contracts with three Public Utility Districts (PUD) for the Mid-Columbia Dams including Grant County PUD, Chelan PUD and Douglas PUD. In 2023, Grant County's "Meaningful Priority Contract" was higher than authorized by approximately $9.4 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 for meeting customer demand, however, the costs associated with the resource contributed to the overall cost variance.

***<u>Item No. 6: Other ($3,175,307 higher than authorized base).</u>*** 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 - $793,304 <u>surcharge</u>. 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 - $790,766 <u>surcharge</u>. 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 - $1,221,372 surcharge. This category is comprised of expenses such as CAISO fees, broker fees, etc.

- Natural Gas Transportation Contracts - $369,865 surcharge. This category reflects the impact of increases in transportation contracts for the upstream Canadian pipelines. These pipelines have annual rate adjustments and are impacted by currency exchange rate differences. These are the primary reasons for the variance in this category.

***Item No. 7 Net Transmission Revenue ($2,256,205 higher than authorized base).*** 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 2023. Higher revenue also resulted from the commencement of long-term transmission sales.

***Item No. 8 Retail Revenue Credit ($1,293,595 lower than authorized base).*** The retail revenue credit represents the average power supply cost on a megawatt-hour 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 31, 2023, this rate was $12.53 approved in Docket UE-220053 et. al. This rate is intended to offset the volume variance associated with the authorized level of costs.

***Item No. 9 Load Variance ($8,236,467 higher than authorized base).*** Load Variance, was higher than authorized by 17 aMW for the year, resulting in approximately $8.2 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 2023?**

A. Yes. In 2023, 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 $1,241,395 in the rebate direction (excluding interest). The primary contributor to this variance was high prices during periods of time when generation were also higher than the levels assumed within the tariff filing. The months particularly impacted were July-August when prices were particularly high. The generation and prices during those months alone contributed to approximately $515,769 of the overall $1,241,395 total benefit. The margin from the Solar Select Program flows through to customers outside of the ERM process at 100%.

## VII. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2023

**Q. Please provide a brief description of new long-term contracts that the Company executed during 2023.**

A. Avista's 2022 All-Source RFP resulted in the acquisition of a new Power Purchase Agreement (PPA) for 100 MW of wind from the Clearwater project in Eastern Montana that is scheduled to begin deliveries in late 2024 and the extension of the existing Lancaster PPA beginning in late 2026. Avista also completed a PURPA contract with Elf 1 Solar in 2023 with scheduled deliveries in mid-2026. Copies of these PPA contracts have been provided as confidential workpapers with this filing.

**Q. Please briefly describe the NextEra Clearwater Wind Contract.**

A. Avista executed a final PPA for NextEra's phase 3 of their Clearwater Wind Project (Clearwater) on January 20, 2023. Clearwater is located approximately 80 miles north of Colstrip Montana, connecting via a gen-tie line constructed by NextEra to the Colstrip Transmission System (CTS), which is also the interconnection point to the Northwestern Energy system (NWE). The terms of this contract resulted in the acquisition of a 100 MW of capacity. The contract will supply Avista with renewable energy from Clearwater, from January 1, 2026 through December 31, 2055. In exchange for a reduced rate, Avista agreed to an early Commercial Operation Date (COD), where Avista will accept delivery of test energy as early as June 1, 2024, with an estimated COD of September 1, 2024.

**Q. Please briefly describe the Lancaster contract.**

A. The Company entered into a PPA for energy and capacity resources from Tyr

Energy's Rathdrum based Natural Gas CCCT (aka "Lancaster") on March 31, 2023, which is an extension of the original contract that expires in October 2026. The Lancaster contract is a tolling agreement for continued sole dispatch of its output of the Lancaster gas plant, located in Rathdrum, Idaho. The plant interconnects directly with Avista at the BPA Lancaster substation. Under the new contract, Avista will continue to pay monthly capacity and energy payments for the sole right to dispatch the plant through December 31, 2041. Lancaster currently supplies Avista with capacity and energy and this contract extends the term from November 1, 2026 through December 31, 2041. The Lancaster executed PPA will help meet Avista's energy and capacity needs as defined in the Company's 2021 IRP. The continuation of the Lancaster agreement provides years of affordable and reliable energy that will benefit Avista's system and its customers.

**Q. Were there any other Purchase Power Agreements entered into by the Company in 2023?**

A. In addition, Avista entered into an a PURPA agreement with Elf I Solar, LLC., to purchase the generation from a solar project to be located in Spokane County. The 19MW solar array has a planned Commercial Operating Date of June 30, 2026, and will have a 15-year contract length, which includes 3 years of the agreement for construction of the facility.

## VIII. THERMAL RESOURCE AVAILABILITY

**Q. 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 - 2023 Thermal Resource Availability</u>**

| Thermal Resource Availability | | |
|---|---|---|
| Kettle Falls | Colstrip 3 & 4 | Coyote Springs II |
| 86.8% | 90.3% | 91.1% |

**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 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 2023 review period are subject to limitations on cost recovery.

## <u>IX. SUPPORTING DOCUMENTATION</u>

**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:

- <u>Natural Gas/Electric Transaction Records:</u> 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 2023, 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.

- 2023 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 2023 Variance Analysis file but provides additional detail on a monthly basis.

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

A. Yes.