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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE POWER COST	)	CASE NO. AVU-E-22-11
ADJUSTMENT (PCA) ANNUAL RATE	)	
ADJUSTMENT FILING OF AVISTA	)	DIRECT TESTIMONY OF
CORPORATION	)	ANNETTE M. BRANDON

FOR AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is Annette M. Brandon. My business address is 1411 E. Mission Avenue, Spokane, Washington, and I am employed by the Company as a Wholesale Marketing Manager in the Energy Supply department.

Q. Would you please describe your educational background and professional experience?

A. Yes. I am a 2002 graduate of Eastern Washington University with a Bachelor of Arts degree in Business Administration – Professional Accounting. I started with Avista in January of 1999, as a Budget Analyst in the Company's Transmission Department. I spent three years in the Company's Tax Department before moving to Resource Accounting for the next eight years. I joined the Regulatory Affairs Department as a Regulatory Analyst in 2012 and was promoted to Manager Regulatory Affairs in 2013. My primary responsibilities in Regulatory Affairs related to oversight of the Purchase Gas Cost (PGA) adjustment filings and Energy Recovery Mechanism/Power Cost Adjustment (ERM/PCA) filings in Washington and Idaho, was a key contact for the Company's compensation and benefits programs, and served as Revenue Requirement Manager for Oregon's general rate case.

I moved to my current role of Wholesale Contracts Manager in the Energy Supply Department in August of 2020. In this role, my responsibilities are related to the ERM and PCA annual filings and support for development of authorized power supply in general rate case proceedings. I am also the primary contact for the Company's transmission contracts, and help to facilitate the Request for Proposals (RFP) processes. In 2021, I led a special project related to the development of Avista's Clean Energy Implementation Plan, which was the first to be filed in the State of Washington.

Q. Have you previously filed testimony in annual Power Cost Adjustment proceedings?

A. Yes. I sponsored the power supply related testimony in the 2021 annual PCA filing. In my previous role in Regulatory Affairs, I supported testimony which provided a summary of accounting entries and account balances related to the Power Cost Adjustment (PCA). Like last year, Company witness Ms. Schultz sponsors the accounting testimony in this filing.

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

A. My testimony gives an overview of power supply operations and provides a summary of the factors contributing to the power cost deferrals during the July 1, 2021 through June 30, 2022 Review Period (Review Period).

Q. Are you sponsoring any work papers and supporting documentation to be introduced in this proceeding?

A. Yes. Detailed work papers supporting the tables and other calculations in my testimony have been provided in electronic format to the Commission, and other parties coincident to this filing. The Company has also provided supporting documentation, including details of all term natural gas and electricity transactions that flowed during the Review Period, and daily position reports that show, among other things, forward price curves. Copies of long-term power contracts that the Company entered during the Review Period have also been provided.

II. OVERVIEW OF POWER SUPPLY OPERATIONS

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

A. Avista 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 our generation and transmission resources. Numerous variables affect short-term power supply positions and prices. As such, we employ an Energy Resources Risk Policy to recognize and actively manage the interaction and dynamics among 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 conditions, ambient conditions, environmental and permit allowances and other factors.

Energy Supply, of which I am a member, is responsible for fuel management, optimizing the use of electric resources including wholesale power contracts, obtaining, and dispatching power resources to meet load obligations and providing good stewardship of electric resources. Variability of resources is inherent because of weather, streamflow and wind conditions, physical and operational limitations, and prevailing market-driven economics related to power and fuel.

Energy resource planning involves significant modeling, assumptions, and estimates. Actual loads are influenced by many factors and therefore rarely match forward estimates. The load and generation net surplus or deficit require 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, we utilize all power and fuel transactions authorized in our Risk Policy to provide reliable and affordable service to Avista's electric loads or obligations and seek 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 time 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.
- Futures 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, and 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 among several variables. We assess these variables to select and execute an appropriate mix for short-term and intermediate-term objectives. Intra-month activity during the prompt 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.

Q. Does the Company have an active hedging program?

A. Yes. 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.

III. OVERVIEW OF DEFERRAL CALCULATIONS

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

A. Energy cost deferrals under the PCA 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 the Review Period result from the power supply revenues and expenses approved by the Commission in Case No. AVU-E-19-04 for July 2021 through August 2021 and Case No. AVU-E-21-01 for September 2021 through June 2022 of the Review Period. 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 PCA also includes changes in Accounts 565 (transmission expense), and 456 (third-party transmission revenue).

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 PCA is multiplied by Idaho's share of the Production/Transmission Ratio (PT Ratio) approved in association with base net power supply expense. Change in Idaho retail sales is then multiplied by the Load Change Adjustment Rate (LCAR) and added or subtracted from the change in power supply expense to calculate the total power expense change. 90 percent of the change in power expense is deferred and 10 percent is retained by the Company.

Q. Please explain how the load change adjustment is calculated in the PCA.

A. The PCA includes a load change adjustment to reflect the change in power production and transmission expense recovered through base retail revenues, related to changes in retail load. The LCAR calculation is based on the energy classified production and transmission costs included in the Company's general rate case. The LCAR revenue adjustment for July 2021 through August 2021 was $22.00/MWh and September 2021 through June 2022 was $24.89/MWh.

The monthly load change adjustment in the PCA 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 PCA 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 PCA deferral (increases power supply costs).

IV. SUMMARY OF DEFERRED POWER SUPPLY COSTS

Q. What were the changes in power costs during the PCA Review Period?

A. During the Review Period, actual net power costs were higher than the authorized (or baseline) net power costs for the Idaho jurisdiction by $5,453,000. After taking into consideration the 90% allowable deferral percent, the total is $4,908,000 in the surcharge direction.

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

A. Average load exceeded authorized (baseline) load by approximately 33 average megawatts (aMW) for the year. Dependent upon timing, economics and resource availability, the Company utilized a mix of resources and market purchases to meet the demands of these additional loads. Meeting the requirements of this additional load, particularly in times of high prices (see Figure 1 below), resulted in net higher than authorized expense. The monthly shape of these variances is provided in Table No. 1 below:

Table No. 1 - Monthly Load Variance Compared to Authorized

Native Load Variance Compared to Authorized Higher (+) Lower (-)												
Period	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22
aMW	153	(4)	(11)	(21)	(12)	52	91	72	24	80	(4)	(16)

The variances generated by each resource component provide the basis for the variance analysis in this testimony. Please see Table No. 2 for the primary components of the variance analysis. Note in all variance tables below, a positive number represents unfavorable; a negative number indicates favorable.

Table No. 2 – Factors Impacting Power Supply Expense

Factors Contributing to Increased Power Supply Expense July 2021 - June 2022 *(in thousands)*				
	Cost Variance	Generation Variance	Total Variance	Idaho Share @ 90%
1. Change in Net Power Purchases (Purchases net of Sales)	$ (20,400)	$ 8,693	$ (11,707)	$ (10,537)
2. Change in retail load	$ (2,801)	$ 7,002	$ 4,200	$ 3,780
				$ -
3. Change in Hydro Generation	$ 1,553	$ 5,583	$ 7,136	$ 6,423
4. Change in Wind Generation	$ 12,529	$ (13,894)	$ (1,366)	$ (1,229)
5. Change in Thermal Generation	$ 2,330	$ (961)	$ 1,368	$ 1,232
6. Change in Natural Gas Plant Generation	$ 13,146	$ (6,422)	$ 6,724	$ 6,051
7. Change in Net Transmission Expense (purchases net of sales)	$ (694)	$ -	$ (694)	$ (625)
8. Other Miscellaneous Expense	$ (209)	$ -	$ (209)	$ (188)
Total Variance to Authorized	$ 5,453	$ 0	$ 5,453	$ 4,908

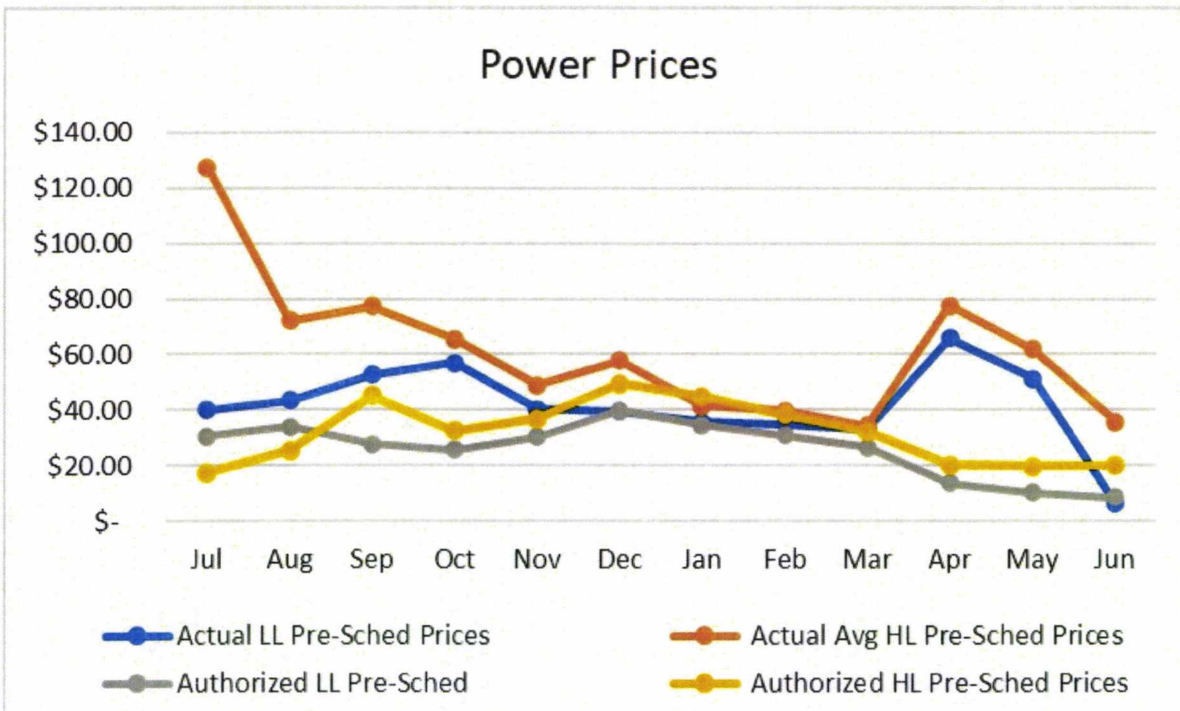
For purposes of this variance analysis, workpapers provided by Avista differentiate between the "cost variance" (which represents the price/quantity variance when comparing the actual values to authorized as recorded to the general ledger), and "generation variance"[1] (which represents the value each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

The 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 our resource mix as compared to authorized.

[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 primary purpose is to provide an indicator as to how each component of our 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. The proxy value of actual HL/LL market prices, is illustrated in Figure No. 1 below:

Figure No. 1 - Power Prices in Review Period



Q. Please describe the contribution of each item shown above in Table No. 2 to the increase in net power supply expenses.

A. Several factors contributed to a surcharge for the annual PCA filing, primarily driven by the increase in load described above for $3.8 million, natural gas plant generation of $6.1 million, and hydro generation of $6.4 million (all Idaho share). These surcharges were primarily offset by favorable net power purchases expense of $10.5 million. The remaining components (comprised of wind and thermal generation, transmission, and other) combine to account for the remaining $0.9 million of the total variance of surcharge of $4.9 million. Provided below is a summary of the factors that, added together, resulted in an increase in power supply expenses for the Review Period **(the "Item" number references back to Table No. 2)**. Please note that the Company is providing work papers supporting all impacts listed in Table No. 2 and described in more detail above.

Item No. 1: Change in Net Power Purchase Expense ($10,537,000 rebate direction). 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 considers several factors including economics, load requirements, and hydro conditions when evaluating the benefits of off-system sales. For the year, sales exceeded purchases for a total net purchase variance of 88 aMW. After assigning the cost and generation variance to each surplus or deficit resource, the value associated with the Net Power Purchase category was favorable by $10.5 million (Idaho share), as shown in Table No. 3 below:

Table No. 3 – Net Power Purchase Variance

Net Purchase Variance Favorable (-) / (+) Unfavorable					
	aMW	Cost	Gen	Total	ID Share $
Purchases	67	$ 8,087	$ (12,434)	$ (4,347)	$ (3,912)
Sales	(156)	$ (28,488)	$ 21,127	$ (7,361)	(6,624)
Net	(88)	$ (20,400)	$ 8,693	$ (11,708)	$ (10,537)

For all months within the Review Period, with the exception of July 2021, Avista was able to sell at a higher price than included in authorized. On an annual basis, sales prices exceeded authorized by approximately $12.00 per aMW, whereas purchases were very close to authorized level with a variance of only $0.43 per aMW. Effectively, when Avista was a net seller, power prices deviated from the authorized prices to a greater degree than prices deviated from the authorized level when Avista was a net purchaser.

Item No. 2: Change in Retail Loads ($3,780,000 surcharge direction). The impact of the change in retail loads is the net of the deviation in actual load versus the authorized level multiplied by the market price of power (netted against the retail revenue adjustment). For the Review Period, Idaho retail sales were 34 aMW above the authorized level. The biggest variance as compared to authorized was in July 2021 at 134 aMW in response to record high heat. In July 2021, peak load conditions, combined with high prices averaging $127.00 per aMW (heavy load), resulted in an unfavorable variance in retail loads of approximately $5.2 million of the $7.0 annual variance.[2] This unfavorable variance was offset by the load change adjustment as prices were higher than the authorized rate. Additional information regarding the LCAR has been provided previously in my testimony.

Item No. 3: Change in Hydro Generation ($6,423,000 surcharge direction). Total hydro generation was lower than the authorized level by 6 aMW. Hydro generation at Company-owned plants on the Spokane River and Clark Fork River were lower than authorized by 4 aMW and 6 aMW respectively. Offsetting this was a favorable 4 aMW variance due to higher than authorized generation from the Mid-Columbia contracted hydro plants. Record high temperatures, combined with lower-than-normal precipitation, resulted in an early seasonal runoff in 2021. Unfavorable hydro conditions contributed to reduced generation in 2021, particularly for the July through October time period. Reduced hydro generation, coupled with high prices resulted in a variance of $2.4 million (of the total $6.4 million) for July alone. The remainder of the Review Period included periods of both favorable hydro generation and unfavorable hydro generation, driven by a variety of factors such as weather, economics, and market conditions.

Item No. 4: Change in Wind Net Expense ($1,229,000 rebate direction). Included in this category is both the Palouse Wind Project and the Rattlesnake Wind Project, which became operational in December 2020. Because these power purchase agreements are

[2] Total annual variance is comprised of $7.0 million generation variance less $2.8 million load change adjustment, for a net annual variance of $4.2 million (prior to sharing).

not included in base rates in Idaho, the increase in net expense in the PCA is a function of the actual hourly generation of the plant times the contract price, offset by the hourly market value of the power generated, resulting in an overall favorable variance. For the Review Period, Palouse Wind provided 40 aMW, and Rattlesnake Flat provided 49 aMW toward serving load. Rattlesnake Flat also had a favorable price variance as compared to authorized, which offsets the higher contract price associated with Palouse Wind.

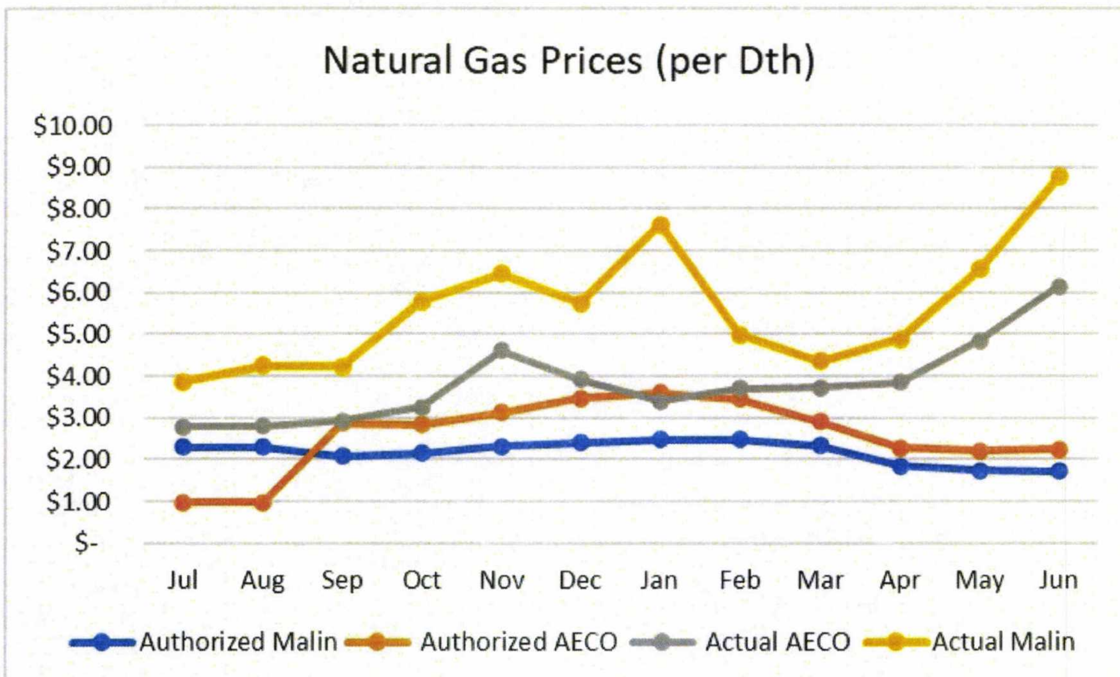
Item No. 5: Change in Thermal Generation ($1,232,000 surcharge direction). The change in the value of thermal generating units at Colstrip and Kettle Falls is a function of the change in generation multiplied by the market price of power, netted against the change in fuel expense. Colstrip generation was approximately 5 aMW above authorized, and Kettle Falls generated 4 aMW below the authorized level. The value of Kettle Falls was $101,000 lower than the authorized level, and the value of Colstrip was $1,332,000 higher than the authorized level, for a total surcharge of $1,232,000. However, the new coal contract that went into effect early 2020 resulted in a higher fuel cost for Colstrip of $29.81 per aMW vs. the authorized level for $17.37 per aMW. This offset the value of the additional generation.

Item No. 6: Change in Natural Gas Generation ($6,051,000 surcharge direction). 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", is Boulder Park, Rathdrum, Kettle Falls CT, and Northeast Combustion Turbine. For the Review Period, natural gas generation contributed an additional 28 aMW above what was embedded in authorized. Lancaster contributed the most to this variance, at 26 aMW above authorized. Coyote Springs 2[3] and Other CT contributed a favorable 8 aMW and an unfavorable 5 aMW, respectively, above authorized. The net value of this

[3] Coyote Springs 2 was down from March – June 2021 for a transformer replacement project, which replaced the three-phase transformer that suffered a failure in 2018 to three single phase transformers This project was outside of the Review Period and was addressed in the 2021 PCA filing.

increased generation was approximately $6.1 million (Idaho share). The value of this additional generation was offset by approximately $11.8 million (Idaho share) in unfavorable fuel expense due to natural gas prices, which were materially higher than authorized as illustrated in Figure No. 2 below. For the Review Period, the average natural gas price was $3.20 per dekatherm (actual) versus $2.58 per dekatherm (authorized).

<u>Figure No. 2 – Natural Gas Prices in Review Period</u>



It is worth noting, however, that the increase in natural gas prices likely contributed to the favorable variance in Item No. 1 Net Purchases, as electric prices were pulled higher and in periods of time when Avista was long generation, this value was captured by selling into the market at prices well above purchases.

<u>Item No. 7: Change in Net Transmission Expense ($625,000 rebate direction</u>). Net transmission expense was above the authorized level primarily due to higher third-party transmission revenues. Third-party transmission revenues, a result from increased purchases or sales from other regional entities utilizing our transmission system, contributed approximately $1.6 million to this variance. Fluctuations in short-term transmission sales are partially a function of other utilities' load/resource balance and whether they are sellers or buyers. Transmission expense was higher than the authorized level by approximately $0.9 million primarily due to the 2022 BPA General Rate Case which was effective October 2021.

Item No. 8: Change in Misc. Expense ($188,000 rebate direction). Miscellaneous Expense consists of broker fees, California Independent System Operator (CAISO) fees, and the Montana Invasive Species. The primary contributor to the variation in this expense was a reduction in the Montana Invasive Species expense.

V. NEW LONG-TERM CONTRACTS ENTERED INTO DURING REVIEW PERIOD

Q. Please provide a brief description of new long-term contracts that the Company entered into during the Review Period.

A. The Company entered into one long-term power purchase contract during the Review Period with Chelan County PUD No. 1. This is a 20-year contract for the output of the Rocky Reach Project. The Company closed out its 2020 RFP with a second contract with Chelan for an additional 5% (88 MW/51 aMW) with delivery starting on January 1, 2026.[4] This contract increases to 10% on January 1, 2031, when an existing Chelan PUD contract expires on December 31, 2030, and continues until 2045. As this contract is not effective until January 1, 2026, it is not included in the Review Period.

The Company also completed two Public Utility Regulatory Policies Act (PURPA) renewals with the City of Spokane for its Waste-to-Energy facility, and Upriver Dam. Together, these contracts contribute an additional 43.7 MW beginning January 1, 2023 through

[4] As noted in my testimony in Case No. AVU-E-21-09 (the 2021 Avista PCA), Avista entered into a 10-year contract with Chelan County PUD No. 1 for the output from the PUD's Rock Island and Rocky Reach hydropower projects from 2024 through 2033.

December 31, 2037. These facilities are located within Washington State and therefore follow Washington's PURPA requirements. However, they are system resources and flow through Idaho's actual and authorized power supply expense.

Finally, two PURPA contracts for the University of Idaho were completed in the Review Period. The first is for the Steam Turbine for 825 kilowatts (kW) effective February 16, 2022 for 20 years. This PURPA was approved by this Commission in Order No. 35462 on July 13, 2022. The second one is for their Solar facility for 132.32 kW with an effective date of February 16, 2022 for 20 years. This PURPA was approved by this Commission in Order No. 35440 on June 22, 2022.

VI. SUPPORTING DOCUMENTATION

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

A. The Company maintains a number of 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 the Review Period, including all key transaction details such as trade date, delivery period, price, volume and counter-party. Additional information can be provided, upon request, for any of these transactions.
- Position Reports: These daily reports for each trading day in the Review Period 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.

- Variance Analysis: This analysis provides the detailed calculation of the differences between actual and authorized for the Review Period for each subsection described above.

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

A. Yes.