REDACTED

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-22____

DIRECT TESTIMONY OF

ANNETTE M. BRANDON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Annette M. Brandon. I am employed by Avista Corporation as a Wholesale Contracts Manager in the Energy Resources Department. My business address is 1411 East Mission, Spokane, Washington.

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

A. My testimony will provide an overview of the history of the ERM and provide a summary of the factors contributing to the power cost deferrals during the 2021 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 two exhibits. First, Exh. AMB-2 contains five pages from the Company's December 2021 Monthly Power Cost Deferral Report previously filed with the Commission. These five pages show the deferral calculations for the period January of 2021 through December of 2021. Page 1 of Exh. AMB-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. I am also sponsoring Exh. AMB-3, which includes the comments provided to the

Commission on August 4, 2021 (Docket U-210484) regarding the "Heat Dome" events that occurred in June/July of 2021.[1]

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 2021?

A. For the 2021 calendar year, actual net power costs were more than authorized for the Washington jurisdiction by $16,360,791 (excluding interest). The deferral in the customer surcharge direction for 2021 amounted to $8,724,712. Pursuant to the mechanics of the ERM, the Company absorbed $7,636,079 of increased power costs in 2021.

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

A. Yes. Company witness Ms. Schultz provides testimony concerning the monthly deferral entries and the deferral balance, and Company witness Mr. Dempsey provides testimony concerning the operation of our various thermal plants.

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

[1] The referenced comments also included numerous attachments, which are provided in the referenced docket, but which have not been duplicated in this Exhibit.

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 1st of each year. This filing provides an opportunity for the 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 30th 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 2020 calendar year was filed March 31, 2021 in Docket UE-210216.

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 our generation and transmission resources. As one can imagine, 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.

IV. SUMMARY OF DEFERRED POWER SUPPLY COSTS

Q. What were the changes in power costs, the amounts deferred, and the amounts absorbed by the Company during 2021?

A. During 2021, actual net power costs were higher than the authorized net power costs for the Washington jurisdiction by $16,360,791 (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 was $16,360,791. Of this total, the Company absorbed $7,636,079 and a deferral was recorded in the amount of $8,724,712 (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%	$ 6,360,791	$ 636,079	$ 5,724,712
	$ 16,360,791	$ 7,636,079	$ 8,724,712

Q. As a result of Order 07 in Avista's 2017 general rate case (Docket UE-170485 et. al.), the Company held several workshops to develop and/or revise inputs and methodologies for the final power supply base included in customers' rates. What was the effective date of these changes?

A. The newly developed methodology for setting the power supply base was authorized in Avista's 2020 general rate case, Docket UE-200900 et. al., and was effective October 1, 2021. As such, the first nine months of the variance in this ERM review period was based on an authorized level of power supply expense with a test period of 12 months ending December 2016 (Docket UE-170485, et. al.).

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

A. Actual load exceeded authorized by approximately 19 aMW for the year. The monthly shape of these variances is provided in Table No. 2 below:

<u>**Table No. 2 - Monthly Load Variance Compared to Authorized**</u>

Load Variance Compared to Authorized													
Period	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Avg.**
aMW	-59	34	-4	-38	-28	140	117	10	-26	-56	25	111	19

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. 3 below provides the primary components of the variance analysis. Please note in all variance tables below, a positive number represents <u>unfavorable;</u> a negative number indicates <u>favorable</u>.

Table No. 3 – Factors Contributing To Increased Power Supply Expense in 2021

Washington Share			
	Cost Variance	Generation Variance	Total
1 Hydro Electric Generation	$ 2,462,576	$ 15,816,334	$ 18,278,910
2 Net Purchases/Sales	$ (256,330)	$ (10,473,596)	$ (10,729,926)
3 Thermal Generation	$ 2,398,083	$ (2,990,099)	$ (592,016)
4 Wind Generation	$ 7,464,495	$ (9,794,674)	$ (2,330,179)
5 Natural Gas Plant Generation	$ 8,120,049	$ (3,624,879)	$ 4,495,171
6 Other	$ 781,396	$ -	$ 781,396
7 Transmission Revenue	$ (3,377,779)		$ (3,377,779)
Total	$ 17,592,490	$ (11,066,913)	$ 6,525,577
8 Load Variance		$ 11,066,913	$ 11,066,913
9 Retail Revenue Credit	$ (1,231,699)		$ (1,231,699)
Total Variance	$ 16,360,791	$ (0)	$ 16,360,791

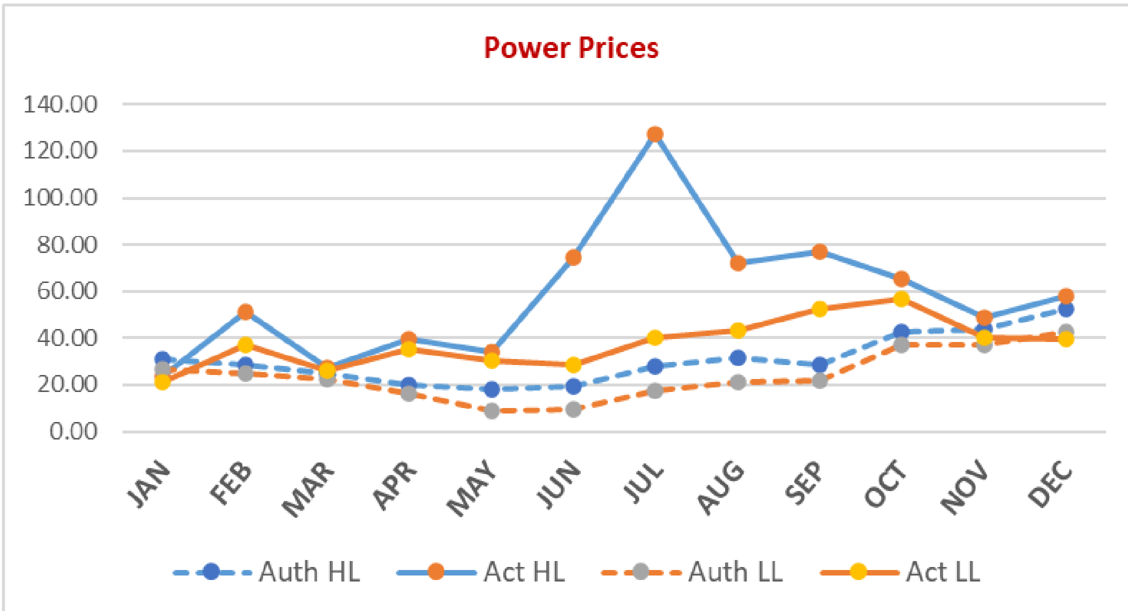
For purposes of this variance analysis, workpapers provided by Avista differentiate between the "cost variance" (which represents the price/quantity variance when comparing the actual values to authorized as recorded to the general ledger), and "generation variance"[2] (which represents the value each 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. 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

[2] 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.

may have impacted these variances including market conditions, hydro conditions, maintenance cycles, weather, and temperatures, among others. The proxy value of HL/LL market prices, as compared to authorized is illustrated in Figure No. 1 below:

<u>Figure No. 1 - Power Prices in 2021</u>

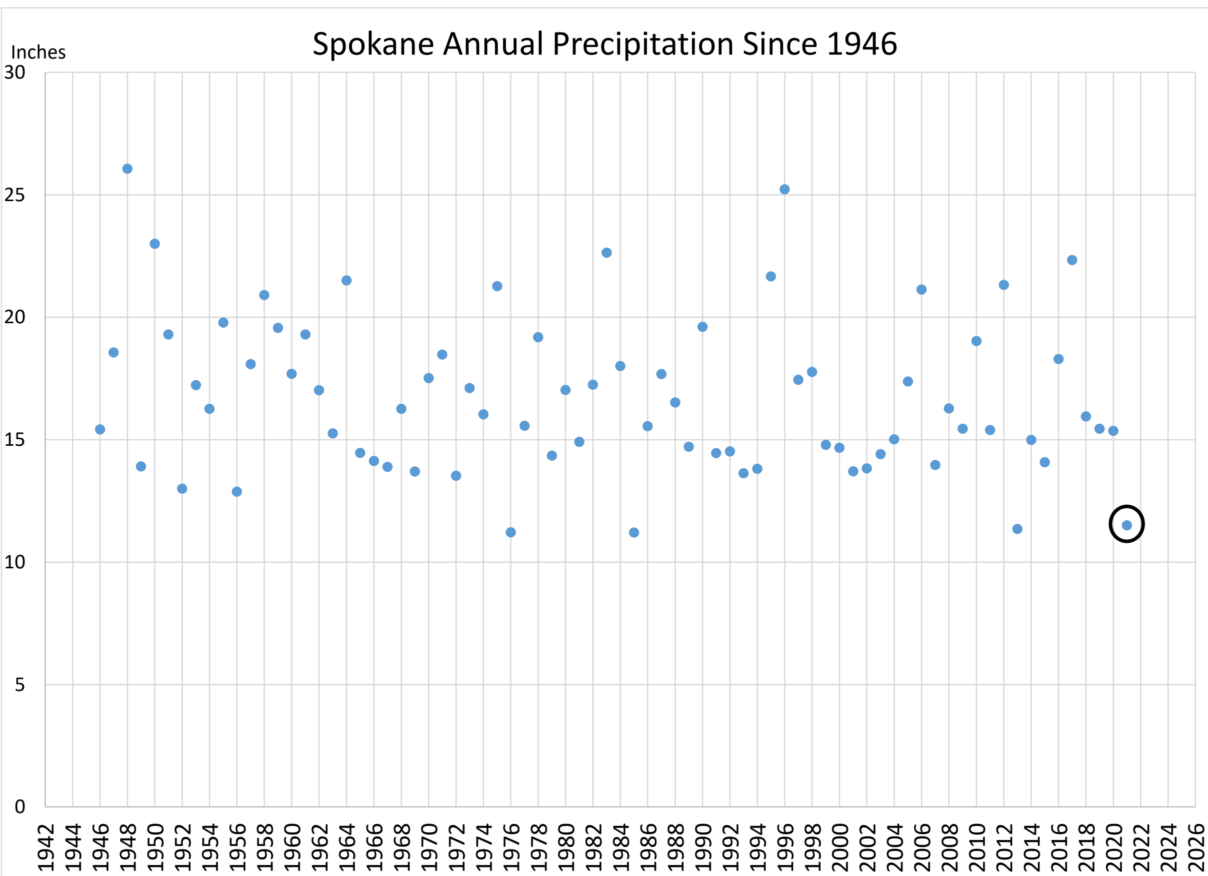


The primary months which contributed to the overall variance were June and July, when loads and prices sharply rose in response to regional temperature spikes, and unfavorable hydro conditions. These increases in load were not limited to Eastern Washington, but rather were widespread throughout the Northwest, further impacting wholesale prices as regional demand increased.

Q. Based on the information provided in Table No. 3 above, the primary contributor in the <u>surcharge</u> direction for 2021 was related to item number *<u>(1) Hydroelectric Generation</u>* (surcharge $18,278,910). Please provide additional context as to this variance.

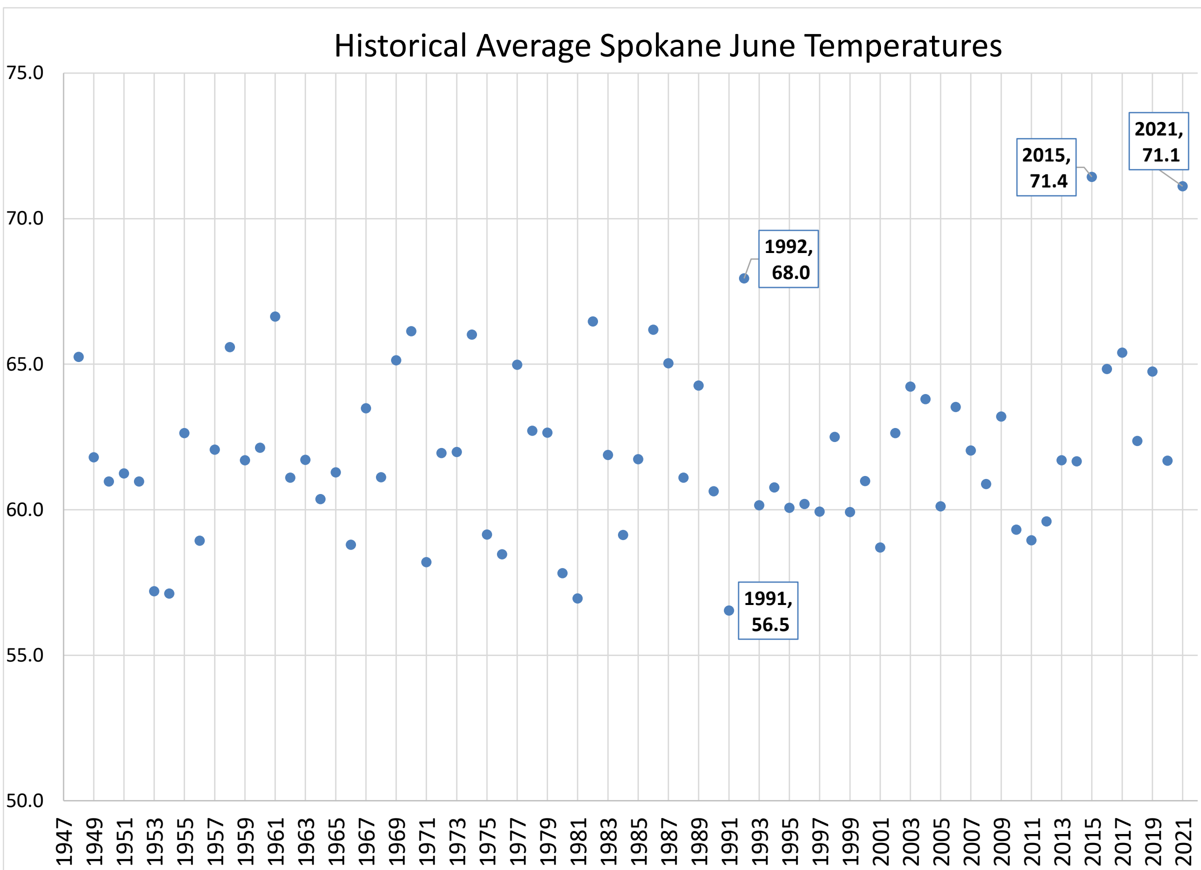
A. As compared to authorized, Avista's hydroelectric generation was 34 aMW lower for the year. The combination of lower-than-normal precipitation in late spring and record high temperatures, especially in June and July, resulted in low flows in the rivers from which Avista generates hydro power. For the year, Spokane saw the 4th lowest annual precipitation on record since 1946 (the year the weather service was established at Geiger Field in Spokane). Early in the year, there was no indication that the summer of 2021 was going to be dry and hot. The snowpack as late as April 15th was 102% in the Spokane drainage and 93.6% in the Clark Fork basin. In fact, slightly cool temperatures contributed to the runoff starting late and resulting in low April hydro generation. Total rainfall for April, May and June in Spokane, however, was only 0.67 inches, compared to normal totals of around 4.44 inches. Figure No. 2 below provides the annual precipitation in Spokane since 1946.

<u>Figure No. 2 - Spokane Annual Precipitation</u>



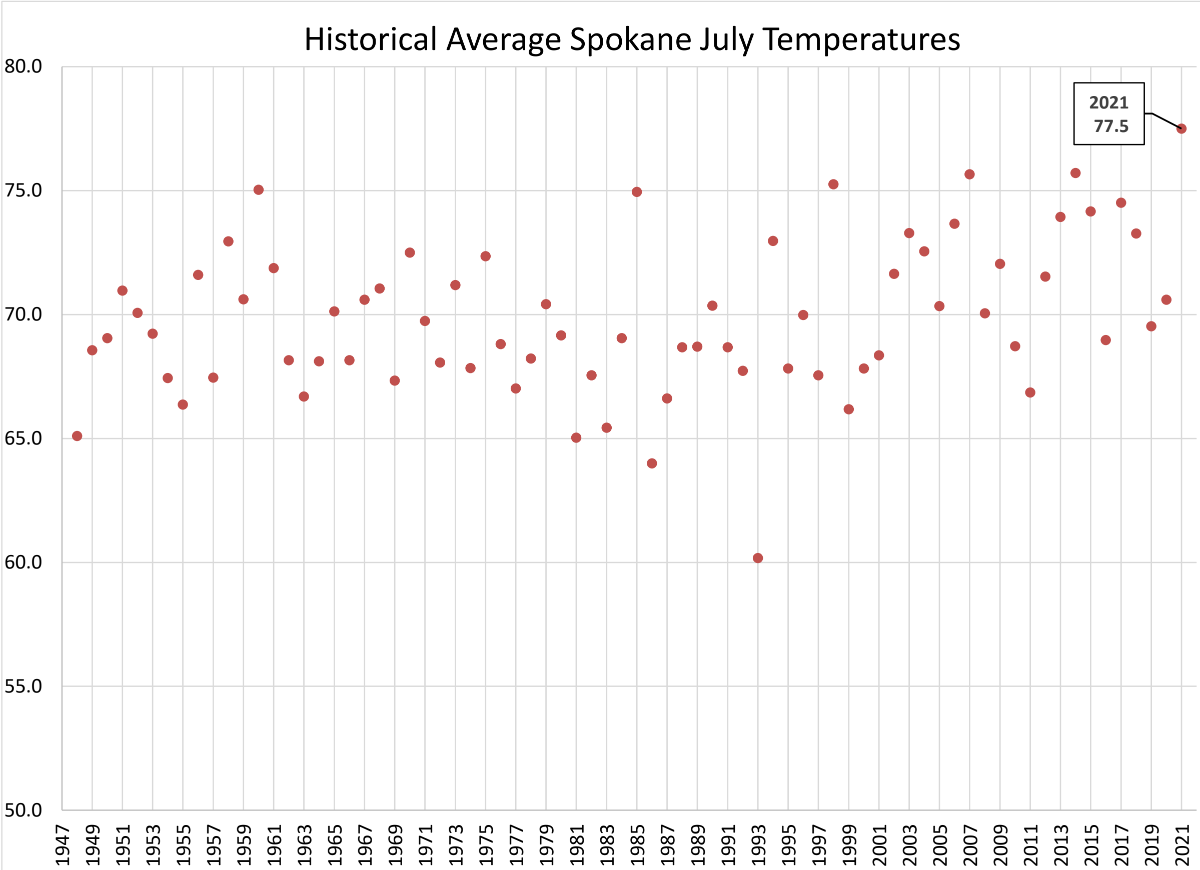
Average temperatures in June were the second highest on record, and average temperatures in July were the highest on record, which contributed to an accelerated late Spring runoff. The tables below illustrate average Spokane temperatures in June and July. Several record high temperatures were set at many locations in Eastern Washington and Northern Idaho. For instance, in Figure No. 3 below, in June, Spokane's average temperature was 71.1 degrees, which was only slightly slower than the previous record that was set at 71.4 in 2015.

Figure No. 3 - June Historical Average Temperatures



In Figure No. 4 below, in July, Spokane reached the all-time highest average temperature at 77.5 degrees.

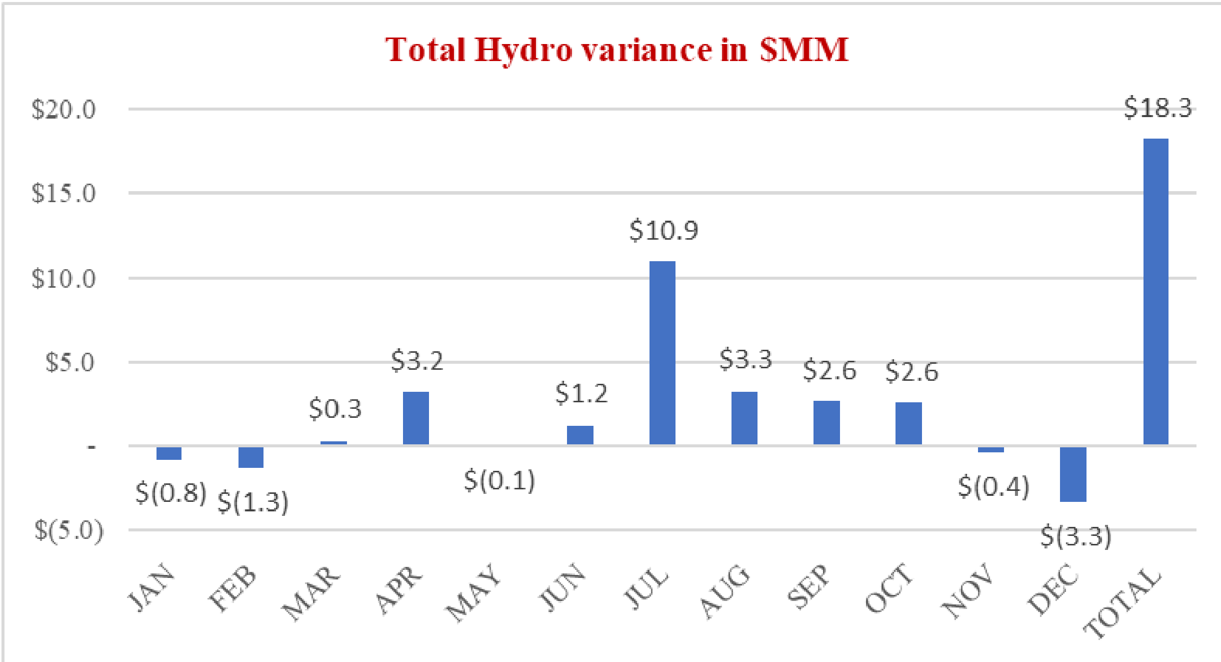
Figure No. 4 - July Historical Average



The unfavorable hydro conditions, compounded with high market prices, significantly impacted the total variance to authorized, as other resources were utilized to meet customer load requirements. As illustrated in Figure No. 5 below, this resulted in an unfavorable annual variance as compared to authorized of $18,278,910.[3] Due to conditions described above, most of the impact was in July, resulting in an approximate $10.9 million variance – or approximately 60% of the total annual hydro variance.

[3] The 80-year water record was utilized to set the base power supply expense for January – September, and median was utilized for October – December.

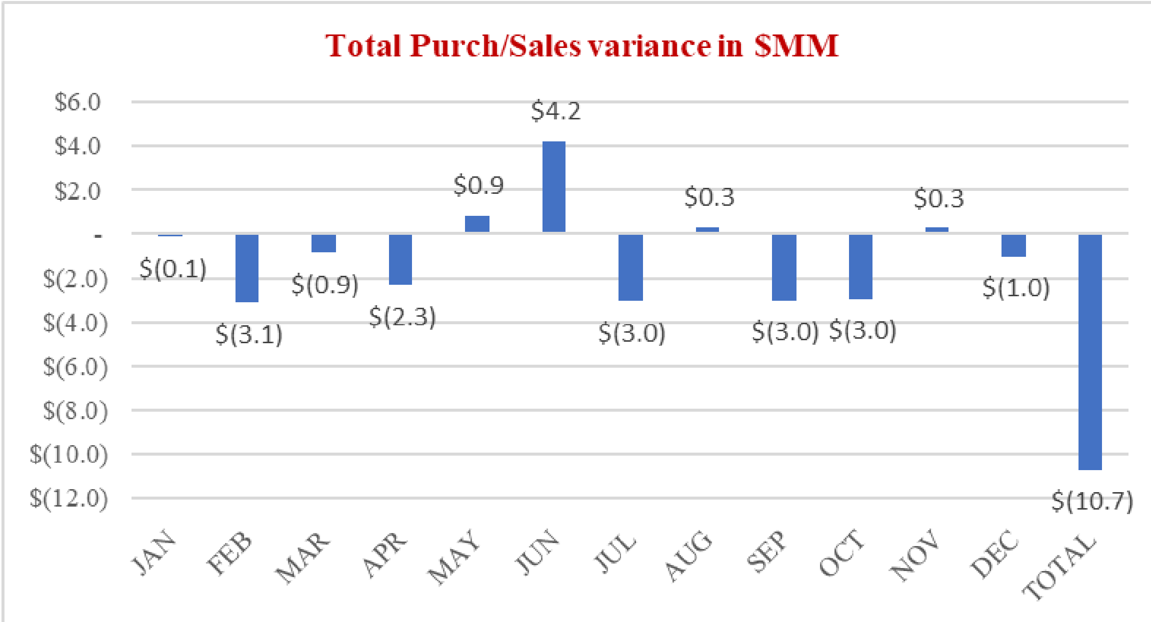
<u>Figure No. 5 - Hydro Variance (in $millions)</u>



Q. Based on the information provided in Table No. 3 above, the primary contributor in the <u>rebate</u> direction for 2021 was related to item number *<u>(2) Net Purchase/Sales</u>* ($10,729,926). Please provide additional context as to 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. For the year, net purchases were above authorized by 7 aMW. After assigning the volumetric/generation variance to each surplus or deficit resource, the Net Power Purchase/Sales category was favorable by $10.7 million, as shown in Figure No. 6 below.

Figure No. 6 - Total Purchase and Sales Variance by Month



There were several contributing factors to this favorable variance. One cause of the favorable variance was that two larger term contracts included in the authorized expenses had expired. [redacted] Another favorable variance occurred because PURPA purchase contracts were renewed at lower prices as compared to authorized, resulting in a favorable variance of $0.8 million. Finally, the remaining $3.5 million favorable variance arose from the price variance of the hundreds of other hourly and monthly transactions when valued at the actual monthly heavy load and light load prices in 2021.

Q. At any point during the year, most especially during the June and July "Heat Dome" event, did Avista make sales into other markets, while choosing not to serve its own customers?

A. Absolutely not. Avista utilized a combination of increased generation from existing resources, as well as net purchases in the market, to meet the increased needs of our customers during the Heat Dome event. As compared to authorized, Avista was a <u>net purchaser</u> during the Heat Dome event. In addition, the deferral was in a <u>surcharge</u> direction for $8.3 million in July. Had Avista been in a net sales position, this benefit would have impacted the deferral balance, and it is likely to assume the deferral would have been in a <u>rebate</u> direction. Any suggestion that asserts Avista sold power instead of serving customers is unfounded; the actual market transactions and resulting financial impact to the Company through the ERM shows otherwise.

While some customers did experience an interruption in service during the Heat Dome event, <u>it was not due to generation availability or constraints</u>, but due to distribution/substation related problems, as stated in reporting provided to the Commission shortly after the event (summarized in Exh. AMB-3). I will touch on the components of the Heat Dome event later in my testimony.

Q. Turning back to the components listed in Table No. 3, would you please describe the variance related to <u>*Item No. 3 Thermal Generation*</u> ($592,016 rebate)?

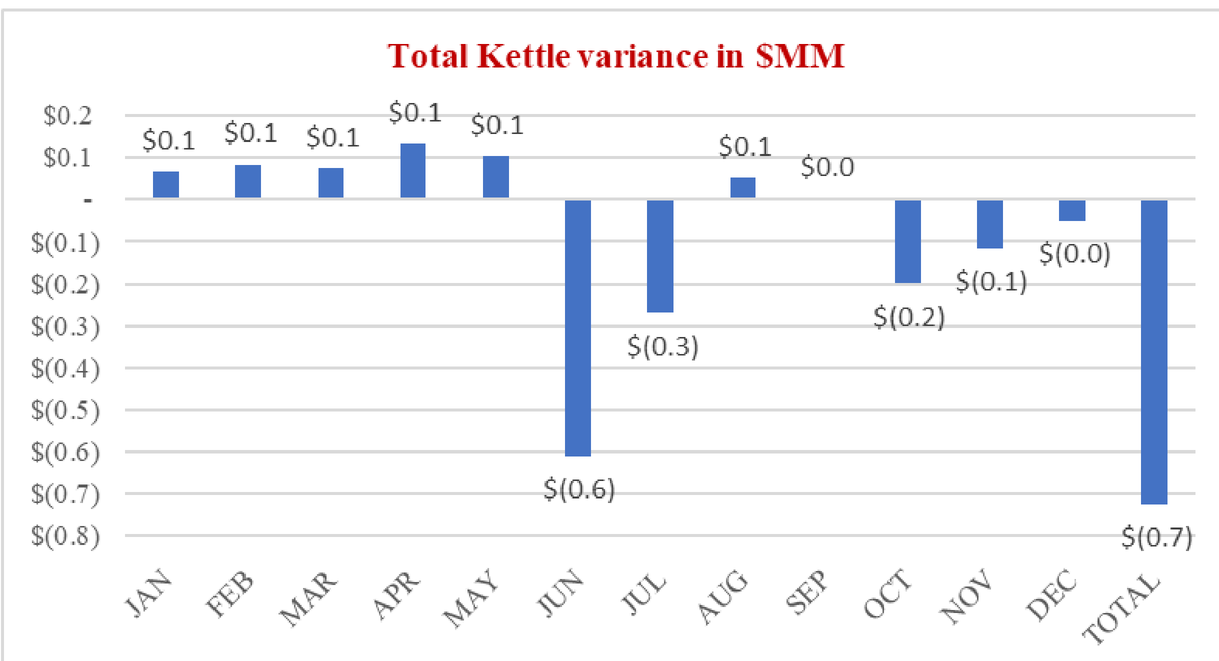
A. Yes. <u>Item No. 3 - Thermal Operations</u>, is comprised of the Colstrip and Kettle Falls Generating Stations, and represents the smallest variance as compared to authorized of all the items listed in Table No. 3 above. The total variance associated with Avista's thermal plants was a total favorable variance of $592,016 or 9 aMW as illustrated in Table No. 4 below.

<u>Table No. 4 – Thermal Generation Reconciliation</u>

Thermal Generation (+) unfavorable / (-) favorable		
	Total Variance	Washington Share
1 Kettle Falls	-$1,101,937	-$724,056
2 Colstrip	$200,950	$132,039
3 Net	-$900,987	-$592,016

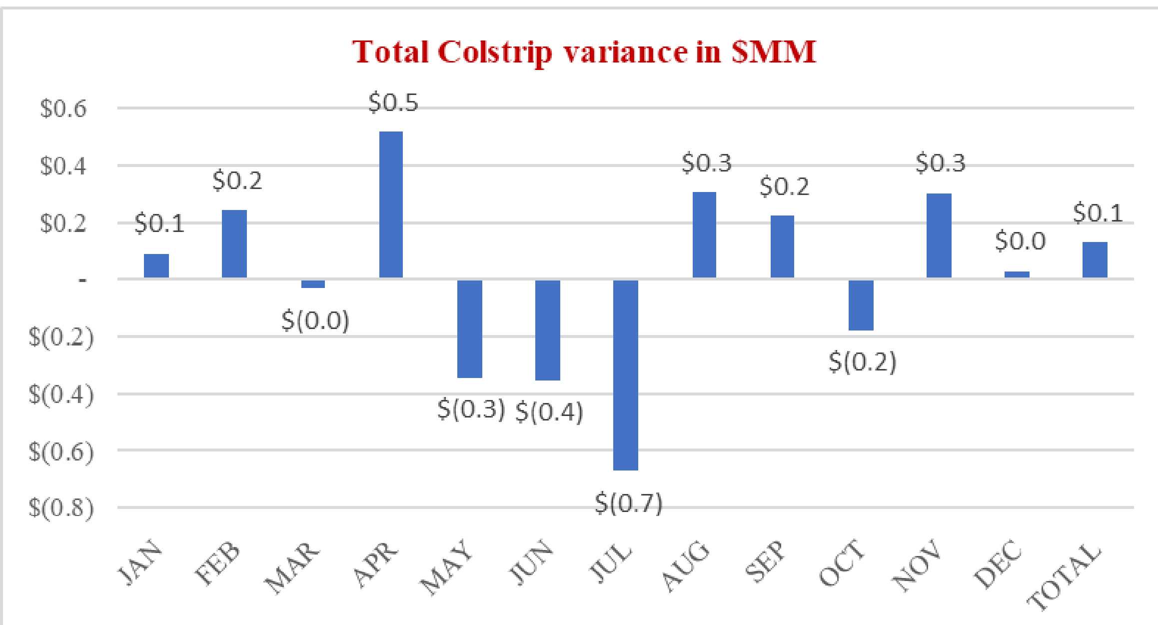
Kettle Falls was the primary component of the overall Thermal Generation variance, with the majority of this variance occurring in June and July. Increased generation at Kettle Falls served approximately 50 aMW above authorized in June and July, resulting in a favorable variance for these two months alone of approximately $900,000 (combined). That can be seen in Figure No. 7 below:

<u>Figure No. 7 - Total Kettle Falls Variance</u>



For Colstrip, it was very close to break even for the year, with a total unfavorable net variance of approximately $132,039. The cost variance associated with Colstrip was approximately $1.8 million of the total variance due primarily to the price variance resulting from the new coal contract which went into effect January 1, 2020. [redacted].[4] The test period authorized expense for the first nine months of the year did not include the impacts of this new contract since it was not known in 2017. This unfavorable cost variance was offset by a favorable generation variance, as Colstrip generation was approximately 7 aMW higher than authorized and provided approximately $1.7 million in additional value above what was anticipated in authorized. Notably, approximately 56 aMW was generated above authorized in June and July, resulting in a favorable variance of $1.1 million for just these two months alone, as shown in Figure No. 8 below:

Figure No. 8 - Total Colstrip Variance

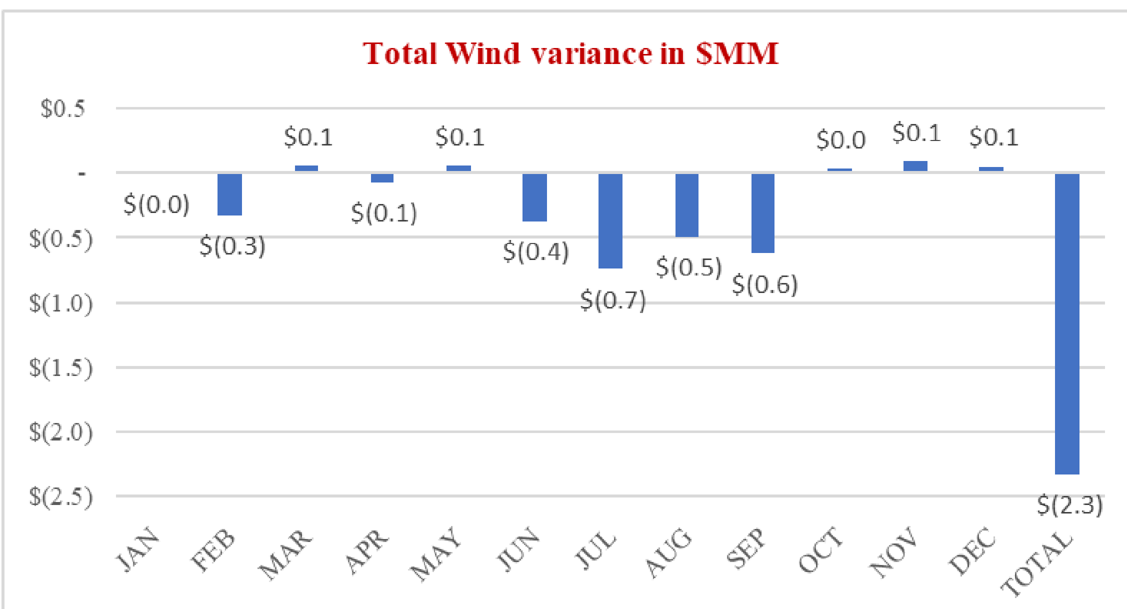


[4] As discussed earlier, the authorized base for 2021 includes 9 months from Docket UE-170485 et. al., and 3 months from Docket UE-200900 et. al.

Q. Would you please describe the variance related to *Item No. 4 Wind Generation* ($2,330,179 rebate) listed in Table No. 3?

A. Yes. Item No. 4 Wind Resources, comprised of the Rattlesnake Flat and Palouse Wind Power Purchase Agreements (PPA), contributed a favorable variance of approximately $2.3 million, providing generation to meet an increase of approximately 37 aMW of load for the year. This favorable variance was primarily due the Rattlesnake Flat Wind Project which went into operation late December 2020 and was not included in the authorized base for most of the year. The impact of this increase in additional generation which helped to offset a portion of our overall shortage in hydro generation previously mentioned. Rattlesnake Flat also had a favorable price variance as compared to authorized, which offsets a higher contract price associated with Palouse Wind. As illustrated in Figure No. 9 below, the value of this additional generation was especially important during the summer months, resulting in a net favorable variance for July – September of $1.8 million.

Figure No. 9 - Total Wind Generation Variance



Q. Would you please describe the <u>total variance</u> related to <u>*Item No. 5 Natural Gas Plant Generation*</u> ($4,495,171 surcharge) listed in Table No. 3?

A. Yes. <u>Item No. 5 Natural Gas Plant Generation</u> 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. In total, natural gas generation was very close to authorized, with a variance of only approximately 1 aMW over authorized, as shown in Table No. 5 below:

<u>Table No. 5 - Natural Gas Plant Variances</u>

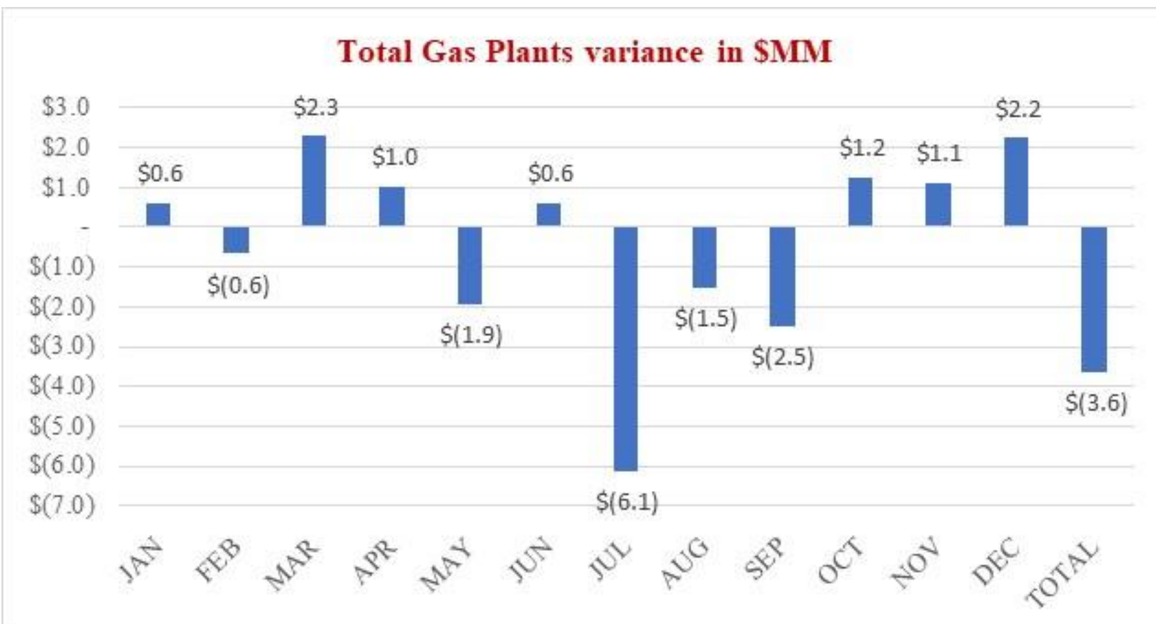
Variance (aMW) (+) unfavorable / (-) favorable				
Month	**Coyote Springs**	**Other**	**Lancaster**	**Total**
Jan	(5)	36	22	53
Feb	(16)	8	(25)	(34)
Mar	205	(14)	(18)	173
Apr	162	(41)	(67)	55
May	40	(5)	(157)	(123)
Jun	44	(26)	4	22
Jul	(67)	(16)	(74)	(158)
Aug	(60)	(5)	(17)	(82)
Sep	(57)	10	(35)	(82)
Oct	13	42	(12)	43
Nov	9	44	(1)	51
Dec	12	48	32	91
	23	**7**	**(29)**	**1**

In total, the variance related to our Natural Gas generation was approximately $4.5 million unfavorable, comprised of a $3.6 million favorable <u>generation variance</u> and a $8.1 million unfavorable <u>cost variance</u>. These variances, in aggregate, are a result of timing differences which resulted in both cost and generation variances.

Q. Staying with "Natural Gas Plant Generation", what were the primary contributors to the $3.6 million favorable <u>generation variance</u>?

A. The generation variance for all natural gas plants was approximately $3.6 million for the year. These variances are most prominent in July when the market value of generation was high as a result of increased demand and lower regional hydro production. The $3.6 million variance is comprised of unfavorable variances for the year at CS2 and Other CT generation for $1.9 million and $2.1 million respectively, offset by favorable variances at Lancaster of $7.7 million.

<u>Figure No. 10 - Total Natural Gas Plant Variance</u>



For the year, CS2 generated 23 aMW less than authorized. The primary generation variance for CS2 was from March through June due to the planned change out of the three-phase transformer with three, single-phased transformers. The transformer replacement project was planned over two years, with the second phase scheduled in 2021. This schedule was established to coincide with a portion of the annual spring maintenance typically scheduled in

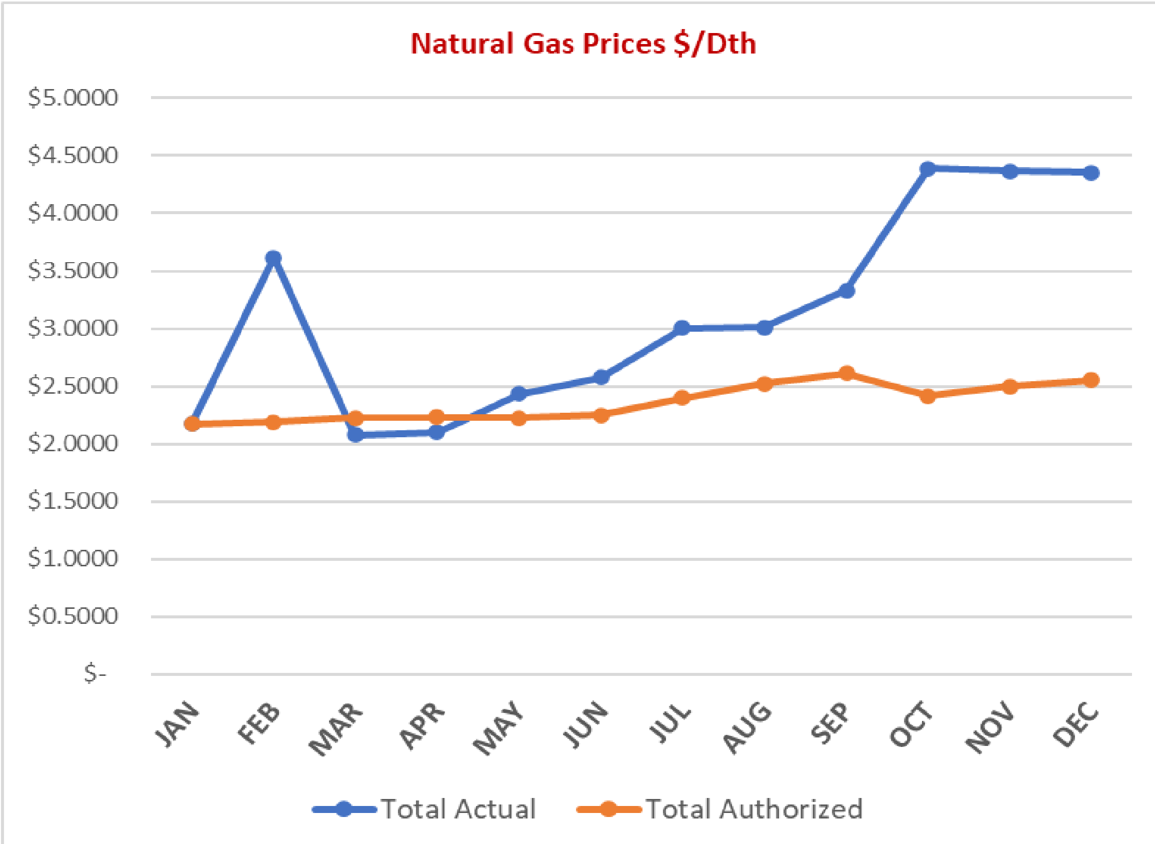
May and June when loads are relatively low and Spring runoff is high. As noted by Company witness Mr. Dempsey, had the outage been performed in a single year, it would have taken eight consecutive months to complete and would have overlapped the summer and/or winter, which are traditionally high-priced market periods. CS2 was returned to service as scheduled on June 30, 2021, and was utilized to meet the increase in customer loads associated with the July heatwave.[5] Through June, the reduced generation compared to authorized resulted in an unfavorable generation variance of $7.0 million. However, the value of this generation during the summer, particularly in July when loads were high and market prices were high, partially offset this unfavorable variance by $5.1 million, for a net annual CS2 generation unfavorable variance of $1.9 million.

Lancaster generation exceeded the authorized level in nearly all months in 2021 as illustrated in Table No. 5 above, resulting in a variance of 29 aMW in generation above authorized, and an annual favorable variance of $7.7 million. Lancaster generated a monthly average of 223 aMW, excluding an outage in June, resulting in equivalent availability factor of just over 90%. As such, the variance at Lancaster was due to monthly dispatch variances, timing of planned maintenance, an extended unplanned outage in June, and differences in market prices.

Several factors impacted the dispatch of Lancaster generation, including wholesale natural gas prices (shown in Figure No. 11 below) and wholesale electric prices (see Figure No. 1 earlier) which resulted in different economics associated with dispatching this resource, as compared to how the plant was modeled in authorized.

[5] CS2 was taken down for approximately 4 days for unplanned maintenance resulting from a leaking crossfire tube and engine tuning July 9 through July 12. Note that this outage was outside of the Heat Dome (June 26 – July 6).

Figure No. 11 - Total Natural Gas Price Variances



In addition, maintenance played a role in the variances compared to authorized. The average maintenance cycle is approximately 14 days in late Spring (May/June), with an extended cycle every five years. The authorized level of maintenance, based on the agreed-upon five-year average, allocates approximately five days to May and an estimated twelve days to June. For 2021, the maintenance cycle was scheduled from June 4 through June 18, contributing to the largest favorable variance for the year in May of 157 aMW. For June, in addition to the planned maintenance cycle, additional issues were uncovered which extended the outage from June 18 to June 28. The net impact of the planned and unplanned outage, combined with other modeling assumptions in authorized, resulted in an unfavorable 4 aMW variance for the month of June.

<u>Other CT</u> generation assets are peaking resources that dispatch less frequently than more efficient base load generation resources. For 2021, these resources were dispatched 7 aMW less than authorized on a net basis. Increased gas prices led to an unfavorable total annual variance of $521,000. However, during the "heat dome" event generation was 21 aMW above authorized, benefitting customers by approximately $911,000 during this period.

Q. Again, staying with "Natural Gas Plant Generation", would you please describe the unfavorable <u>cost variance</u> of $8.1 million?

A. Yes. The higher cost of fuel for these natural gas generation facilities resulted in an unfavorable cost variance of $8.1 million. Natural gas prices[6] were approximately $0.77 per Dth higher than authorized for the year, resulting in the substantial cost variance. The highest variation in natural gas prices occurred in the fourth quarter with an actual average price of $4.39 per Dth compared to an authorized amount per Dth of $2.49 - a net difference of $1.90 per Dth. There are several factors which impacted the increase in natural gas prices. Initially the main driver of the increase in prices was the supply and demand imbalance as a result of the COVID-19 pandemic. Natural gas production recovery from the pandemic stalled in November 2020 and remained relatively stable until August 2021, when there was a sharp decrease in production resulting from hurricane outages in the Gulf of Mexico. During this period of reduced production, demand was continuing to recover and grow, primarily a result of LNG exports. As such, storage levels were lower than normal at the end of the injection season, resulting in the higher prices for the fourth quarter.

Increases in LNG exports were primarily influenced by natural gas prices in Europe. Prices in Europe at the start of winter were around $30/Dth (prior year they were in

[6] For ease of reference, natural gas prices for both CS2 and Lancaster were averaged.

the $5-$7 range). Compounding this, natural gas storage was extremely dire in Europe due to reduced gas flows from Russia. We anticipate this cost pressure trend to continue as recent European natural gas prices have been in the $70-$90/Dth range in response to the war in Ukraine. Along with the high prices, there has been tremendous volatility both in Europe and to a lesser extent in the US markets.

In 2021, several stretches of cold temperatures resulted in volatility in natural gas prices with prices spiking, and receding, settling at an overall price level that has been much higher than we have seen the past several years. The level of authorized natural gas prices in the ERM base did not anticipate the increase in wholesale natural gas prices during 2021, as illustrated in the actual to authorized natural gas prices provided in Figure No. 11 above.

Q. Returning to Table No. 3, would you please describe the variance related to *Item No. 6 Other* ($781,396 surcharge)?

A. Yes. Item No. 6. Other, is comprised of variances related to variable natural gas pipeline transportation contract expense, transmission expense, the Lancaster power purchase agreement (PPA), and miscellaneous small charges. The net impact of these individual components is a net variance of approximately $781,000 unfavorable compared to authorized. The primary components are as follows:

- Gas Pipeline Contact Expense $1.188 million favorable variance. This variance is primarily due to general rate cases on US pipelines and annual adjustments for Canadian pipelines. Several adjustments have been made since the level of authorized was established in 2017.

- Lancaster Power Purchase Agreement - $1.058 million unfavorable. The Lancaster PPA includes a variable portion and a fixed portion intended to cover Capital and Operation & Maintenance costs. The level in authorized would have been for the pro-forma period 2018 and did not include the known increases in the contract through to 2021. In addition, the increase in generation over authorized resulted in an increase in variable expenses.

- Transmission Wheeling Expense - $556,000 unfavorable. 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 - $354,000 unfavorable. This category is comprised of expenses such as CAISO fees, broker fees, etc. The primary contributor to this variance was CAISO transaction fees which were not included in the authorized level of expense until October 2021.

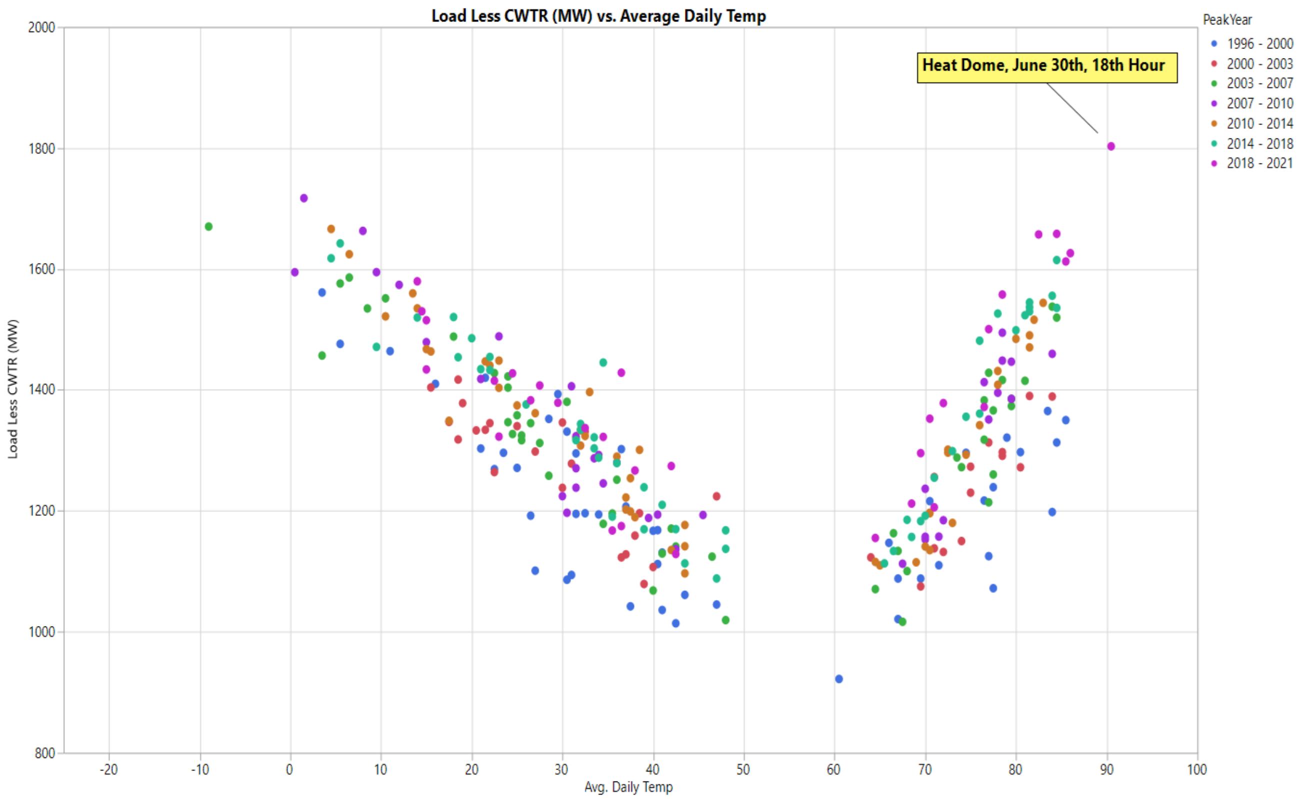
Q. Would you please describe the variance related to *Item No. 7 Transmission Revenue* ($3,377,779 rebate) listed in Table No. 3?

A. Transmission revenue was higher than the authorized level resulting primarily from higher than normal short-term and non-firm use of Avista's transmission system from June through September of 2021. 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 our Annual Transmission Revenue Requirement (which applies to BPA Network Service) rose 53%. Additionally, Avista entered into a new long-term firm point-to-point transmission service agreement with Idaho Power for 100 MW of service commencing on May 1, 2021 and continuing through April 30, 2026. The value of that contract in 2021 was $1.825 million (system).

Q. Would you please describe the variance related to *Item No. 8 Load Variance* ($11,066,913 surcharge) listed in Table No.3?

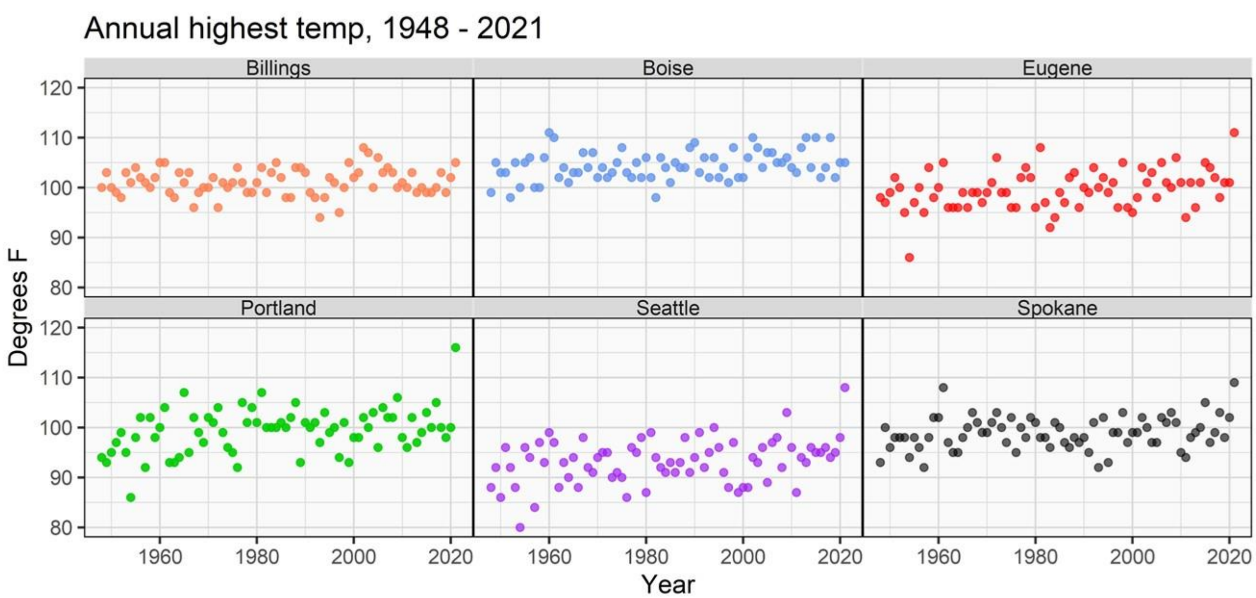
A. Yes. Item No. 8 Load Variance was higher than authorized by 19 aMW for the year, resulting in $11.1 million in additional expense as compared to authorized. This additional load variance is reallocated in the variance analysis to the generation which contributed to meeting load. For purposes of this variance analysis, the additional load is valued at the market price. Particularly during the June and July timeframe, customer loads reached an all-time high as a result of unseasonably hot, record-setting heat. As illustrated in Figure No. 12 below, on June 30, 2021 at the 18th hour, Avista's system reached the highest ever summer peak at approximately 1800 MW. It is no surprise that this increase was heavily correlated with the increase in temperatures previously discussed.

Figure No. 12 – MW vs. Average Daily Temp



The record temperatures occurred across the entire Northwest, impacting major cities like Spokane, Seattle, Portland and Eugene. While temperatures were at record-setting levels for longer in Eastern Washington as compared to Western Washington and Oregon, it is important to note that the higher temperatures impacted loads across the region, pushing peaks to all-time high levels and putting more stress on the overall electric system. All else being equal, the market responded to this increase in regional demand by pushing prices to the highest level of the year (as shown in Figure No. 1). The net impact of the increased loads, valued at proxy market prices, was approximately $2.9 million in June and $5.3 million in July alone (including the impact of the retail revenue credit).

<u>Figure No. 13 - Average Highest Temperature 1948 – 2021</u>



Q. Please summarize how the Company responded to the Heat Dome event in June and July 2021.

A. Beginning on Monday, June 28, 2021, Eastern Washington began to experience a record heatwave, with temperatures reaching and exceeding 110 degrees in some areas. The heatwave placed an unprecedented strain on Avista's electrical distribution system. During the course of the heatwave, Avista saw loads exceed all previous records; in fact, at the height of the event, Avista saw additional loads that were roughly equivalent to 40,000 additional homes on the system.

Avista prepared for these conditions considering potential impacts to supply, transmission and distribution. All areas postponed routine work to both minimize any disruptions and ensure that the system was fully available. Additional planning for Avista's energy supply included purchasing additional power in anticipation of increased load, decreased market supply, and wholesale price volatility, coordinating with power plants to put contingency plans in place, accelerating plans to return generation to service from scheduled maintenance and upgrades, and identifying load reduction opportunities. Additional planning for the Avista distribution system included proactively shifting electric load to accommodate increased usage in certain areas. In addition, on Monday, June 28, 2021, Avista began requesting that customers do what they could to help conserve electricity.

Q. In summary, were the outages related to the Heat Dome event a power supply or power generation issue?

A. No. The outages related to the Heat Dome event were not a power supply issue, and were limited to distribution-related issue as explained above. The Company was well positioned to cover forecasted energy demands through a combination of Company-owned assets and existing purchase agreements as well as the ability to acquire additional resources through the market. The net result was a resource stack that included all of the components discussed in the above variance analysis (i.e., hydro generation, thermal generation, wind generation, natural gas plant generation, and finally increases in net purchase and sales). My workpapers provide additional detail for each component and the generation and cost variance associated with each. Please see Exhibit AMB-3 for a copy of the report provided to the Commission regarding the Heat Dome and distribution system limitations.

Q. Commission Staff informally inquired of the Company after the Heat Dome event as to why there was a substantial difference between Avista's power supply cost

variances, and those of Puget Sound Energy and Pacific Power. What was the Company's response?

A. Staff's communication in late Summer 2021 noted a difference between Avista's power supply cost variance versus those of our peer utilities. Previously, through the power supply workshop process, Avista described the differences in the overall resource stack between the three Washington utilities (PacifiCorp, Puget Sound Energy, Avista), noting how Avista is heavily hydro dependent, and how a higher proportion of our overall load is served through natural gas generation as compared to our peer utilities (who have more coal in their resource mix, for example). As such, the impact of poor hydro conditions and higher wholesale natural gas prices will impact our overall costs more substantially. That said, the Company has no way of knowing the exact resources utilized by our peers to meet their specific requirements during the Heat Dome event, which of course occurred in a slightly different timeframe than that experienced by Avista. Variances between authorized costs and actual costs are not only a factor of resource mix, energy loads, and wholesale power/natural gas prices, but also differences between the authorized values in each utility's power supply baselines.

Q. Finally, please describe the impacts of the line No. 9 _ Retail Revenue Credit**_ ($1,231,699 rebate) on line 9 of Table No. 3.**

A. The retail revenue credit represents the average power supply cost on a Megawatt hour (MWh) basis. This rate is based on the authorized level of power supply costs as approved in the Company's general rate case. For the initial nine months of 2021, this rate was $18.11 in accordance with Docket UE-170485 et. al., and effective October 1, 2021, the rate was reduced to $15.37 in accordance with Docket UE-200900 et. al. This rate is intended to offset the volume variance associated with the authorized level of costs. For 2021, the total annual load variance as compared to the weather normalized amount included in authorized was higher by 61,066 MWhs. The calculation of this variance is included in Exhibit No. AMB-2, page 3.

Q. Are there any other factors which affected the Power Supply Deferral for 2021?

A. Yes. In 2021, the Company tracked the revenues and expenses associated with the Solar Select Program approved by this Commission in Docket UE-180102. The net margin associated with this Program was approximately $892,000 in the rebate direction. The primary contributor to this variance was prices which were higher than the level of expense assumed within the tariff filing. Average prices were especially high during the months of May through July, for the reasons previously discussed. The generation and prices during those months alone contributed to approximately $657,000 of the overall $892,000 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 2021

Q. Please provide a brief description of new long-term contracts that the Company executed during 2021.

A. The Company entered two (2) long-term power purchase contracts in 2021 with Public Utility District No. 1 of Chelan County ("Chelan"), stemming from Avista's 2020 renewable Request for Proposals (RFP). In March, the Company completed a contract which resulted in the acquisition of a 5% Fixed Cost Slice (88 MW / 51 aMW) of Chelan's "Chelan Power System" (CPS) consisting of Rocky Reach and Rock Island hydro projects located on the Columbia River. The contract will supply Avista with output from the combined operation of Chelan's Rocky Reach and Rock Island hydro-electric projects with planned delivery of renewable energy and capacity to Avista for 10 years, beginning on January 1, 2024 and continuing through December 31, 2033.

In addition, 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. This contract increases to 10% on January 1, 2031, when an existing Chelan contract expires on December 31, 2030, and continues until 2045. These two contracts are outside the review period for this ERM filing, however, they have been provided for informational purposes only.[7]

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 2021 review period are subject to limitations on cost recovery.

VI. THERMAL RESOURCE AVAILABILITY

Q. Please describe the availability factor requirement and actual availability factors for the Company's major thermal plants, specifically Kettle Falls, Colstrip, CS2 and Lancaster.

A. The 2006 Settlement Agreement in Docket No. UE-060181 regarding the continuation of the ERM included potential limitation of the recovery of fixed costs associated

[7] While not a long-term Power Purchase Contract, the Company also entered into a contract with Pend Oreille Public Utility District for the Dynamic Services agreement for 14 aMW October 1, 2021 through September 30, 2026.

with Kettle Falls, Colstrip, CS2 and Lancaster generating plants when the plants fail to meet a 70% availability factor during the ERM review period. The Equivalent Availability Factors[8] for the Company's thermal plants during 2021 are shown in Table No. 6 below.

Table No. 6 - 2021 Thermal Generation Plant Availability Factors

2021 Thermal Generation Plant Availability Factors	
Cosltrip	81.30%
Coyote Springs 2	64.50%
Kettle Falls	88.30%
Lancaster	90.62%

Mr. Dempsey, on behalf of the Company, provides further details regarding the issues regarding CS2 and the 64.5% availability factor in 2021.

VII. 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 2021, including all key transaction details such as trade date,

[8] Note "equivalent availability factor" is an industry-standard calculation: Total available hours minus outages (forced and planned) divided by Total available hours. This is not meant to represent the North America Electric Reliability Corporation (NERC) required Generating Availability Data System (GADS) calculation which is done within NERC's system for conventional generating units that are 20 MW and larger.

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.

- 2021 Variance Analysis. This excel files provides detailed calculations for hydro and thermal authorized and actual values by month. In addition, the "Summary" tab which 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 2021 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 2021 result from the power supply revenues and expenses approved by the Commission in Docket No. UE-170485, et. al. for the January – September 2021 timeframe and Docket No. UE-200900, et. al. for the October – December 2021 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.

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. Fifty percent of power cost increases, or 75 percent of the decreases, between $4.0 million and $10.0 million, and ninety 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. 7 below:

Table No. 7 - 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 in 2021 was $18.11/MWh for January through September 2021, and $15.37 for October through December 2021.

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 2021 deferral report are included as Exh. AMB-2. The December 2021 deferral report pages show all of the months, January through December of 2021. Please note these pages represent a subset of the December 2021 Report provided as Exh. AMB-2.

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

A. Yes.