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BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-19____

DIRECT TESTIMONY OF

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is William G. Johnson. 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 Resources Department.

Q. What is your educational background?

A. I am a 1981 graduate of the University of Montana with a Bachelor of Arts Degree in Political Science/Economics. I obtained a Master of Arts Degree in Economics from the University of Montana in 1985.

Q. How long have you been employed by the Company and what are your duties as a Wholesale Marketing Manager?

A. I started working for Avista in April 1990 as a Demand Side Resource Analyst. I joined the Energy Resources Department as a Power Contracts Analyst in June 1996. My primary responsibilities involve power contract origination and management and power supply regulatory issues.

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

A. My testimony will provide an overview of the history of the Energy Recovery Mechanism (ERM) and provide a summary of the factors contributing to the power cost deferrals during the 2018 calendar year review period. I provide an overview of the documentation the Company has provided in workpapers, which the Company has agreed to provide in the ERM Settlement Stipulation approved and adopted in Docket No. UE-030751. My testimony will also briefly describe how the power cost deferrals are calculated.

Q. What was the ERM deferral amount in 2018?

A. For the 2018 calendar year, actual net power costs were less than authorized net power costs for the Washington jurisdiction by $15,544,268. The deferral in the customer rebate direction for 2018 amounted to $9,489,841 (excluding interest). Pursuant to the mechanics of the ERM, the Company retained $6,054,427 in 2018.

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

A. Yes. Company witness Mr. Ehrbar provides testimony concerning the monthly deferral entries and the deferral balance. In addition, Company witness Mr. Dempsey provides testimony describing the generation interruptions at Colstrip Units #3 and #4, as well as Coyote Spring 2, during 2018.

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

A. Yes. I am sponsoring Exh. WGJ-2, which are four pages from the Company's December 2018 Monthly Power Cost Deferral Report previously provided to the Commission. These four pages show the deferral calculations for the period January 2018 through December 2018. Page 1 of Exh. WGJ-2 shows the calculation of the deferral, pages 2 through 3 show the actual expenses and revenues, and page 4 shows the retail revenue adjustment. 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.

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 No. 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 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 to be 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 2017 calendar year was filed March 28, 2018 in Docket No. UE-180261. Order 01 was issued in that docket on June 28, 2018, and the Commission found that the power cost deferrals for 2017 were properly calculated and recorded.

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. As such we employ the Energy Resources Risk Policy to recognize and actively manage the interaction and dynamics among these variables by establishing processes for future load and obligation estimation, resource estimation, and management of the expected net surplus or deficit Short Term position.

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 (which impacted Avista in 2018, as discussed by Mr. Dempsey), transmission constraints, fuel availability and conditions, ambient conditions, environmental and permit conditions and other factors.

Energy Resources, of which I am a member of, 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 provide 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 a number of estimates. Actual loads rarely match forward estimates precisely. The net surplus or deficit requires constant attention and its variability dictates that flexibility be maintained at all times. It is necessary to buy and sell energy (or financially equivalent derivative transactions) in hourly, daily, monthly and longer increments, and adjust dispatch plans to meet prevailing conditions. As such, we may use any electricity and fuel transactions that are authorized in our Risk Policy to the extent that they relate directly or indirectly to serving Avista Utilities electric loads or obligations and optimizing the value of Avista Utilities energy resources.

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

A. The following are example types of transactions permitted in the context of managing Avista's energy resources and serving the Company's obligations in the Short-Term and Immediate-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 Utilities 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 Utilities 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 Utilities 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's 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 or 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 Utilities 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 gas basis spread based on 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 2018?

A. During 2018 actual net power costs were lower than the authorized net power costs for the Washington jurisdiction by $15,544,268. 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), 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), as it the case with this filing, 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 Company retained $6,054,427 in 2018.

The deferral in the customer rebate direction for 2018 amounted to $9,489,841 (excluding interest). The total ERM deferral for 2018 amounted to $9,696,264 which consists of the following two items:

1. Rebate amount of $9,489,841 related to $4.0 million in the deadband, 75% of the net power costs residing in the $4.0 million to $10.0 million sharing band, and 90% of the net power costs residing in the over $10.0 million sharing band.
2. Rebate amount of $206,423 related to interest.

Q. Please summarize why actual power supply expense was lower than the authorized level during the review period?

A. Table No. 1 below shows the primary factors impacting power supply expense during 2018:

<u>Table No. 1:</u>

	Factors Contributing to Decreased Power Supply Expense 2018 - Washington Allocation	
1	Change in Hydro Generation	-$2,260,606
2	Change in Gas Generation and Natural Gas Prices	-$14,637,079
3	Change in Colstrip & Kettle Falls Generation and Fuel Expense	-$369,857
4	Change in Net Power Purchase Expense	$2,003,936
5	Change in Net Transmission Expense (Expense - Revenues)	-$1,799,356
6	Change in Palouse Wind Net Expense	$722,430
7	Change in Retail Loads (Power Cost Change less Retail Revenue Adjustmer	$2,530,206
8	Change in Power Product Sales and Misc Expense	-$1,733,942
	Total Expense Below the Authorized Level	-$15,544,268

Notes:
1 Hydro generation was 19 aMW above the authorized level.
2 Includes change in gas generation net value and gas transport value.
3 Includes change in generation and fuel expense.
4 Increased expense due to high power prices in certain months.
5 Increased transmission revenue exceeded increased transmission expense.
6 Includes change in generation and purchase expense.
7 Cost increase during higher load period plus retail revenue adjustment.
8 Revenue from sale of additional ancillary products.

Q. Based on the information provided in Table No. 1 above, the primary contributor to the decrease in power supply expense in 2018 was related to changes in "Gas Generation and Natural Gas Prices". Would you please provide additional information related to this contributing factor?

A. Yes. The largest factor affecting power supply costs, as compared to authorized, was revenue captured through the use of firm natural gas transportation contracts and reduced natural gas generation expense. For 2018, natural gas generation and natural gas prices reduced power supply expense by approximately $14.6 million below the authorized level. This is shown in Table No. 1 as ***Item No. 2 Change in Gas Generation and Natural Gas Prices (-$14,637,079)***. The primary contributor to this reduction was low natural gas prices at the AECO natural gas trading hub, and relatively higher natural gas prices at the Malin natural gas trading hub. Avista was able to capture the increased price spreads between those basins in 2018 by utilizing its firm natural gas transportation contracts to purchase natural gas at a low price at AECO, and sell natural gas into the higher-priced Malin market, thereby locking in a favorable benefit for our customers.

Q. Please provide further details on the price (or basis) spreads between AECO and Malin?

A. The AECO natural gas trading hub experienced an unprecedented reduction in prices in 2018 caused by over supply conditions partly due to reduced demand from the eastern United States. Natural gas supplies from Alberta had previously been transported across Canada in order to meet natural gas demands in the Northeast. However, with the proliferation of natural gas production resulting from hydraulic fracturing in Pennsylvania and the Northeast, the demand for natural gas from other regions, like Alberta, was diminished. This led to an oversupply and a price drop at AECO. As for Malin, it serves as a major natural gas hub for higher priced regions, especially California. In the end, the price spread between AECO and Malin was more than double historical levels, as shown in Table No. 2 below.

Table No. 2

Year	AECO	Malin	Spread
2015	$2.11	$2.52	$0.41
2016	$1.64	$2.34	$0.70
2017	$1.67	$2.73	$1.06
2018	$1.18	$2.74	$1.56

In addition, the Company was also able to take advantage of market opportunities by purchasing lower cost natural gas, generating electricity from it, and selling the generated electricity at the Mid-Columbia ("Mid-C") electricity trading hub, again locking in favorable spreads for customers. As a result of the falling AECO natural gas prices, in part, the effective average 2018 transacted natural gas cost was $1.83/dekatherm compared to $2.57/ dekatherm in authorized expense.

Avista's natural gas generation facilities generated 7 aMW less than the authorized level in 2018. This was partially due to an incident in late 2018 when Coyote Springs 2 was either taken offline, or operated at a reduced level, due to step-up transformer issues. Mr. Dempsey provides a complete description of the outage issue at Coyote Springs 2 in his testimony provided in this proceeding.

Market power prices were high during those months so the Company was forced to purchase additional higher-priced power to replace the lost generation. The Company calculates that the incident at Coyote Springs 2 during October and December increased power supply expense by approximately $4.6 million (Washington allocation). This estimate was developed by pricing out at market prices the reduced generation, versus the authorized level, and netting the increased expense resulting from reduced generation with reduced fuel expense, versus the authorized level. Despite the reduced value due to the transformer issues, Coyote Springs 2 net impact (i.e., actual versus authorized) for the entire year was approximately a positive $363,000 (rebate direction) because of lower gas costs to run the plant and/or selling into favorable market prices.

Overall, natural gas generation and natural gas prices shown as item No. 2 in Table No. 1 lowered power supply expense below the authorized level by approximately $14.6 million, and was the primary reason for the overall rebate direction of the ERM in 2018.

Q. Please describe the components which contributed the remaining $0.9 million in reduced power supply expenses.

A. Provided below is a summary of the other factors that, coupled together, resulted in the remaining $0.9 million in reduced power supply expenses for 2018 (the "Item" number references back to Table No. 1):

<u>Item No. 1 Change in Hydro Generation ($2,260,606 rebate direction)</u>. One factor lowering power supply expense was an additional 19 aMW of hydro generation above the authorized level. Generation in the first six months of the year was well above the authorized level, while generation in the second half of the year was below normal. All of the benefit was observed on the Clark Fork River, at our Noxon Rapids and Cabinet Gorge Hydroelectric Generating Facilities. The Spokane River generation plants value was lower than the authorized value due to above average spring temperatures that increased runoff and associated spill and an extremely dry summer. Just like wholesale electric and natural gas prices, hydro generation is very weather dependent and difficult to predict.

<u>Item No. 3 Change in Colstrip and Kettle Falls Generation ($369,857 rebate direction)</u>. The change in the value of 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. The value of Kettle Falls was $578,451 higher than the authorized level (rebate direction), while the value of Colstrip was $208,594 less than the authorized level (surcharge direction), for a net rebate of $369,857 rebate. Kettle Falls generated 9 aMW above the authorized level. Colstrip generated 7 aMW less than the authorized level partially due to an incident during July and August when Colstrip was offline or operated at a reduced level due to the inability to meet certain emission standards. Mr. Dempsey provides a complete description of the outage issues at Colstrip in his testimony provided in this proceeding. The Company estimates that the incident at Colstrip during July and August alone increased power supply expense by $3.5 million (Washington allocation). This estimate was developed by pricing out the reduced generation, versus the authorized level, and netting the increased expense resulting from reduced generation with reduced fuel expense, versus the authorized level. Despite the incident, Colstrip performed close to their expected level over the course of the entire year. In total, for 2018 the Company calculates that Colstrip increased power supply expense by $208,594 versus the authorized level.

Item No. 4 Change in Net Power Purchase Expense: ($2,003,936 surcharge direction). This category is a function of the authorized level of short-term purchases and sales times the difference in actual market prices versus authorized prices, plus any incidental changes in contract expenses not related to changes in generation. Effectively, when Avista was a net buyer, power prices deviated from the authorized prices to a greater degree than prices deviated from the authorized level when Avista was a net seller. The Pacific Northwest region experienced significantly volatile market prices during the Summer of 2018 primarily as a result of higher temperatures and reduced generation (partially due to Colstrip emission issues). In addition, prices were also high in November and December due to the rupture of the Enbridge pipeline.

Item No. 5 Change in Net Transmission Expense ($1,799,356 rebate direction). Net transmission expense was below the authorized level primarily due to higher third-party transmission revenues. Transmission expense was slightly lower than the authorized level and third-party transmission revenue was much higher than the authorized level. Third-party transmission revenues result from increased purchases or sales from other regional entities utilizing our transmission system. Fluctuations in short-term transmission sales are partially a function of other utilities' load/resource balance and whether they are sellers or buyers.

Item No. 6 Change in Palouse Wind Net Expense ($722,430 surcharge direction). The increase in net Palouse Wind power purchase expense was a function of the deviation of the actual hourly generation pattern versus the authorized generation pattern. For the year, Palouse Wind generated 3 aMW below the authorized level, which would typically push the ERM in the rebate direction. However, the hourly deviation in generation was such that there was less generation in higher priced on-peak hours and greater generation in lower priced off-peak hours. The resulting lower overall reduced value of the generation was greater than the reduced power purchase expense, resulting in a surcharge direction impact of the Palouse Wind contract.

Item No. 7 Change in Retail Loads ($2,530,206 surcharge direction). The impact of the change in retail loads is the net of the deviation in actual retail load versus the authorized level times the market price of power netted against the retail revenue adjustment. For the entire year, Washington retail sales were 9 aMW below the authorized level. However, in periods when retail sales were higher (primarily August), prices were also very high, which more than offset the savings in periods when retail sales were less than the authorized level. In addition, because retail sales were below the authorized level for the entire year, the retail revenue adjustment was in the surcharge direction, which combined with the increased expense of serving load resulted in the overall surcharge impact of the change in retail load.

<u>Item No. 8 Change in Power Product Sales and Misc. Expense ($1,733,942 rebate direction)</u>. There were additional ancillary capacity product sales beyond what was included in the authorized level. Additional ancillary capacity sales were primarily for two entities that operate wind facilities and need additional energy balancing services. The contracts for these sales were signed after the rate case pro forma adjustment was developed and/or are variable in the volumes requested and the volumes provided by Avista. Avista does not sell these products at a loss, however, we also don't know how much money we will make selling these products in a given year since we don't not know if the entities will actually need these services and the exact volumes they will request.

In summary, $14.6 million out of the total $15.5 million of net decrease in power supply expense was due to "Change in Gas Generation and Natural Gas Prices", primarily driven by lower AECO gas prices and the large increase in the price spread between the AECO and Malin trading points. This resulted in lower natural gas generation costs and a significant increase in natural gas transport trading revenues for the year. All other factors, netted together, accounted for less than $1 million of the reduction in total power supply expense in the ERM. The Company is providing workpapers supporting all impacts listed in Table No. 1 and described in more detail above.

<u>V. NEW LONG-TERM CONTRACTS ENTERED INTO IN 2018</u>

Q. Please provide a brief description of new long-term contracts that the Company entered into in 2018.

A. The Company entered into two long-term power purchase contract in 2018. In September, the Company entered into a 63 month contract with Douglas County PUD for a

10% share of the output of the Wells dam beginning October, 2018. In October, a PURPA contract was entered into with the City of Cove, for the purchase of the output of an 800 kilowatt hydro-electric generation plant for 20 years.

Q. Are any long-term contracts subject to the limitation for inclusion in the ERM that was part of the settlement in Docket No. 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 2018 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 and Coyote Spring 2 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 with Kettle Falls, Colstrip and Coyote Springs 2 generating plants when the plants fail to meet a 70% availability factor during the ERM review period. Availability factors for the Company's thermal plants during 2018 are shown in Table No. 3 below.

Table No. 3: 2018 Thermal Generation Plant Availability Factors

Colstrip	82%
Coyote Springs 2	82%
Kettle Falls	85%
Lancaster	95%

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 2018, 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 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.

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 2018 result from the power supply revenues and expenses approved by the Commission in Docket No. UE-150204 for the months of January through April and Docket No. UE-170485 for the months of May through December. 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 changes 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 gas turbines and power supply's 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. 4 below:

<u>Table No. 4:</u>

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 2018 was $15.66/MWh for the months of January through April and $18.11/MWh for the months of May through December.

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 2018 deferral report are included as Exh. WGJ-2. The December 2018 deferral report pages show all of the months, January through December of 2018. Please note these pages represent a subset of the December 2018 Report provided as Exh. PDE-2.

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

A. Yes.