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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-17-01 DIRECT TESTIMONY OF TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your duties?

A. Yes. I am responsible for preparing the electric cost of service studies for the Company, as well as providing support for the preparation of results of operations reports, among other things.

Q. What is your educational background and professional experience?

A. I am a graduate of Washington State University with a Bachelor of Arts degree in General Humanities in 1982, and a Master of Accounting degree in 1990. As an employee in the State and Federal Regulation Department at Avista since 1991, I have attended several ratemaking classes, including the EEI Electric Rates Advanced Course that specializes in cost allocation and cost of service issues. I am also a member of the Cost of Service Working Group and the Northwest Pricing and Regulatory Forum, which are discussion groups made up of technical professionals from regional utilities and utilities throughout the United States and Canada concerned with cost of service issues.

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

A. My testimony and exhibits will cover the Company's electric revenue normalization adjustment to the test year results of operations, the proposed Load Change Adjustment Rate to be used in the Power Cost Adjustment and Fixed Cost Adjustment mechanisms, and the electric cost of service study performed for this proceeding. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit No. 14 composed of three schedules. Schedule 1 details the calculation of the proposed Load Change Adjustment Rate, Schedule 2 includes a narrative of the electric cost of service study process, and Schedule 3 presents the electric cost of service study summary results.

Q. Were these exhibit schedules prepared by you or under your direction?

A. Yes, they were.

II. ELECTRIC REVENUE NORMALIZATION

Q. Would you please describe the electric revenue normalization adjustment included in Company witness Ms. Andrews' pro forma results of operations?

A. Yes. The electric revenue normalization adjustment represents the difference between the Company's actual recorded retail revenues during the 12-months ended December 2016 test period, and base rate retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $1,208,000, as shown in adjustment column 2.07 on page 6 of Ms. Andrews' Exhibit No. 12, Schedule 1.

The revenue normalization adjustment consists of four primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) to base tariff rates presently in effect, 2) adjusting customer load and revenue to a 12-month calendar basis (unbilled revenue adjustment), 3) weather normalizing customer usage and revenue, and 4) eliminating both the deferred revenue associated with the

2016 Fixed Cost Adjustment (FCA) mechanism as well as a true-up to the 2015 earnings test provision.

Q. Since these elements are combined into a single adjustment, would you please identify the impact of each component?

A. Yes. A breakdown of the four components of the revenue normalization is as follows:

1. The re-pricing of billed usage including the effects of the January 1, 2017 base rate increase (AVU-E-16-03), as well as the elimination of adder schedule revenue and related amortization expense (Schedule 59 Residential Exchange Credit, Schedule 91 Public Purpose Tariff Rider, Schedule 95 Optional Renewable Power and Schedule 97 Rebate of Electric Earnings Test Deferral)[1] results in an <u>increase</u> to net income of $3,115,000.
2. The re-pricing of unbilled calendar usage and elimination of unbilled adder schedule revenue and expense results in a <u>decrease</u> to net income of $96,000.[2]
3. The weather adjustment <u>increases</u> net income $2,343,000.
4. The elimination of the 2016 FCA deferred revenue and 2015 earnings test provision true-up <u>decreases</u> net income by $4,154,000.

The combined impact of these four elements is an increase to net income of $1,208,000.

[1] Municipal Franchise Fee and Power Cost Adjustment revenues and related expenses are eliminated in separate adjustments.

[2] The unbilled adjustment consists of removing December 2015 usage billed in January 2016 from the 2016 test year, adding December 2016 usage billed in January 2017 to the 2016 test year, and re-pricing the net usage at present base rates.

Q. Earlier you stated that customer usage is "adjusted for any known and measurable changes". What material usage adjustments were made to the 2016 test year?

A. Two large customers shifted from Schedule 21 to Schedule 25 during the test year. In addition, the usage on Schedule 25P is expected to be reduced later in 2017, prior to new rates going into effect. Both of these changes were reflected in the re-pricing of billed usage. These estimated load reductions from the test year were provided to Mr. Kalich in order to capture the associated cost reduction in the power supply adjustment.

Q. Have you quantified the impact of the load reductions since the last general rate case on the revenue requirement in this case?

A. Yes. Pumping Service Schedules 31/32 had reductions in usage compared to the 2015 test year billing determinants used to set present rates. For Schedule 25P, in addition to the expected reduction in load later in 2017 indicated above, the 2016 test period Schedule 25P load is already lower than the load in 2015. The following table compares the usage and revenues expected from the rates approved in Case No. AVU-E-16-03 with the usage and revenues at present rates in this case for Schedule 25P and Schedules 31/32:

Table No. 1[3]

	Schedule Number	Case No. AVU-E-16-03	Case No. AVU-E-17-01	Difference
Revenue $000s				
Ex. Lg. Gen. Service	25P	$ 21,634	$ 19,145	$ (2,489)
Pumping Service	31,32	$ 5,919	$ 5,494	$ (425)
Total Revenue Difference		$ 27,553	$ 24,639	$ (2,915)
kWh's				
Ex. Lg. Gen. Service	25P	419,473,590	362,572,860	(56,900,730)
Pumping Service	31,32	65,364,271	60,392,324	(4,971,947)
Total kWh difference		484,837,861	422,965,184	(61,872,677)

Q. Please briefly summarize the electric weather normalization process.

A. The Company's electric weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the 2016 test period to the amount expected if weather had been normal. This adjustment incorporates the effect of both heating and cooling on weather-sensitive customer groups. The weather adjustment is developed from a regression analysis of ten years of billed usage per customer and billing period heating and cooling degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day and use-per-customer-per-cooling-degree day) are applied to monthly test period customers and the difference between

[3] Lower power costs associated with these reduced loads, estimated using the proposed PCA Load Change Adjustment Rate, would be approximately $1.5 million resulting in a net revenue requirement impact of approximately $1.4 million.

normal heating/cooling degree-days and monthly test period observed heating/cooling degree-days.

Q. Have the seasonal weather sensitivity factors been updated since the last rate case?

A. Yes. The factors used in the weather adjustment are based on regression analysis of monthly billed use-per-customer from January 2006 through December 2015, which is the most recent completed analysis.

Q. What data did you use to determine "normal" heating and cooling degree days?

A. Normal heating and cooling degree days are based on a rolling 30-year average of heating and cooling degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year. The calculation includes the 30-year period from 1987 through 2016.

Q. Is this proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Idaho?

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation is consistent with the methodology presented in Case No. AVU-E-16-03.

Q. What was the change in kWhs resulting from weather normalization for the 12-months ended December 2016 test year?

A. Weather was warmer than normal throughout 2016. Since electric usage is impacted by both heating and cooling, weather normalization required an addition to usage for warm weather during the winter and spring that was partially offset by a reduction to usage for the hot summer months.

Overall, the adjustment to normal required the addition of 766 heating degree-days during the heating season,[4] and the deduction of 19 cooling degree-days during the summer season.[5] The annual total adjustment to Idaho electric sales volumes was an addition of 42,628,368 kWhs, which is approximately 1.5% of billed usage.

The electric system monthly weather adjustment volumes were provided to Company witnesses Mr. Kalich and Mr. Johnson as an input to the Pro Forma Power Supply adjustment.

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[4] The heating season includes the months of January through June and October through December.

[5] The summer season includes the months of June through September. June is included in both seasons because both heating load and cooling load fluctuations occur during the month.

III. PROPOSED LOAD CHANGE ADJUSTMENT RATE

Q. What is the Load Change Adjustment Rate?

A. The Load Change Adjustment Rate (LCAR) is part of the Power Cost Adjustment (PCA) mechanism that prices the change in power supply-related costs associated with the change in actual retail loads from the retail loads that were used to set the PCA base costs. The LCAR determination process for all Idaho investor-owned utilities was established in IPUC Case No. GNR-E-10-03, Order No. 32206, which was approved on March, 15, 2011. The LCAR is also a key component in the Company's electric Fixed Cost Adjustment (FCA) mechanism.[6]

Q. How is the rate determined?

A. The proposed LCAR was determined by first computing the proposed revenue requirement on the total production and transmission costs contained within Ms. Andrews' Idaho electric pro forma total results of operations. The production/transmission revenue requirement amount is then divided by the Idaho normalized retail load used to set rates in order to arrive at the average production and transmission cost-per-kWh embedded in

[6] As required in the Company's FCA, the LCAR from the PCA (grossed up for revenue-related expenses) multiplied by kWh sales is deducted from base rate revenues in the FCA to ensure that no overlap occurs between the PCA and the FCA.

proposed rates. This amount is then multiplied by the proportion of production and transmission costs classified as energy-related in the cost of service study. The LCAR, therefore, represents the energy-related portion of Avista's production and transmission costs, on a per-kWh basis.

Q. Do you have an exhibit schedule that shows the calculation of the proposed LCAR for the 2018 and 2019 rate years?

A. Yes. Exhibit No. 14, Schedule 1 begins with the identification of the production and transmission revenue, expense and rate base amounts included in each of Ms. Andrews' actual, restating, and pro forma adjustments to results of operations. The "2018 Pro Forma Total" on Line 30 at the bottom of page 1 shows the resulting production and transmission cost components.

Page 2 shows the revenue requirement calculation on the production and transmission cost components. The rate of return and debt cost percentages on Line 2 are inputs from the proposed cost of capital. The normalized retail load on Line 10 comes from the workpapers supporting the revenue normalization adjustment. Line 11 represents the average total production and transmission cost-per-kWh proposed to be embedded in Idaho customer retail rates. Lines 12 and 13 are values taken from the cost of service study report titled

"<u>Functional Cost Summary by Classification at Uniform Requested Return</u>" which represents total costs at unity. Line 12 shows the amount of production and transmission costs classified as energy-related, while Line 13 shows the total production and transmission costs in the study.

The same process is repeated for the 2019 rate year pro forma period on pages 3 and 4 of Exhibit 14, Schedule 1. ("2019 Pro Forma Total" production and transmission cost components are shown on Line 35 of Page 3).

The resulting 2018 LCAR on Page 2, Line 14 is $0.02489 per kWh or $24.89 per MWh. The resulting 2019 LCAR on Page 4, Line 14 is $0.02534 per kWh or $25.34 per MWh. The calculation of the LCAR for each rate year will be revised based on the final production and transmission costs, and rate of return, that are approved by the Commission in this case.

<u>IV. ELECTRIC COST OF SERVICE</u>

Q. Please briefly summarize your testimony related to the electric cost of service study.

A. I believe the Base Case cost of service study presented in this case is a fair representation of the costs to serve each customer group. The Base Case study shows Residential Service Schedule 1, Extra Large General Service

Schedule 25, and Pumping Service Schedules 31/32 provide less than the overall rate of return under present rates. All of the other service schedules provide more than the overall rate of return under present rates to varying degrees.

Q. What is an electric cost of service study and what is its purpose?

A. An electric cost of service study is an engineering-economic study, which separates the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. The groups are made up of customers with similar load characteristics and facilities requirements. Costs are assigned or allocated to each group based on, among other things, test period load and facilities requirements, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers.

The study results are used as a guide in determining the appropriate rate spread among the groups of customers. Schedule 2 of Exhibit No. 14 explains the basic concepts involved in performing an electric cost of service study.

It also details the specific methodology and assumptions utilized in the Company’s Base Case cost of service study.

Q. What is the basis for the electric cost of service study provided in this case?

A. The electric cost of service study provided by the Company as Exhibit No. 14, Schedule 3 is based on the 2018 Pro Forma Study presented by Ms. Andrews in Exhibit No. 12, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 14, Schedule 3?

A. Yes. Exhibit No. 14, Schedule 3 is composed of a series of summaries of the cost of service study results. The summary on page 1 shows the results of the study by FERC account category. The rate of return by rate schedule and the ratio of each schedule’s return to the overall return are shown on Lines 39 and 40. This summary was provided to Company witness Mr. Ehrbar for his consideration regarding rate spread and rate design. The results will be discussed in more detail later in my testimony.

Pages 2 and 3 are both summaries that show the revenue-to-cost relationship at current and proposed revenue. Costs by category are shown first at the existing schedule returns (revenue); next the costs are shown as if all schedules were providing equal recovery (cost). These comparisons show how far current and proposed rates are from rates that would be in alignment with the cost study. Page 2 shows the costs segregated into production, transmission, distribution, and common functional categories. Line 44 on page 2 shows the target change in revenue which would produce unity in this cost study. Page 3 segregates the costs into demand, energy, and customer classifications. Page 4 is a summary identifying specific customer-related costs embedded in the study.

The Excel model used to calculate the cost of service and supporting schedules has been included in its entirety both electronically and in hard copy in the workpapers accompanying this case.

Q. Given that the specific details of this methodology are described in the narrative in Exhibit No. 14, Schedule 2, would you please give a brief overview of the key elements and the history associated with those elements?

A. Yes. Production costs are classified to energy and demand in this case based on the system load factor. The Company has proposed this approach in prior general rate cases (Case Nos. AVU-E-11-01, AVU-E-15-05 and AVU-E-16-03).

Transmission costs are classified as 100% demand and allocated by the average of the 12 monthly coincident peaks.

This methodology is the same treatment as the last three Idaho cases (Case Nos. AVU-E-12-08, AVU-E-15-05 and AVU-E-16-03) and reflects the methodology accepted in the Settlement in Case No. AVU-E-10-01.

Distribution costs are classified and allocated by the basic customer theory accepted by the Idaho Commission in Case No. WWP-E-98-11.[7] Additional direct assignment of demand-related distribution plant has been incorporated to reflect improvements accepted by the Commission in Case No. AVU-E-04-01.

Administrative and general costs are first directly assigned to production, transmission, distribution, or customer relations functions. The remaining administrative and general costs are categorized as common costs and have been assigned to customer classes by the four-factor allocator accepted by the Idaho Commission in Case No. AVU-E-04-01.

Q. Does the Company's electric Base Case cost of service study follow the methodology filed in the Company's last electric general rate case in Idaho?

A. Yes.

[7] Basic customer cost theory classifies only meters, services, and street lights as customer-related plant; all other distribution facilities are considered demand-related.

Q. What is the Company proposing in this case with regard to the peak credit methodology?

A. In this case the Company is proposing to use the system load factor to determine the proportion of the production function that is demand-related.[8] This peak credit ratio is then applied uniformly to all production costs. This is the same method the Company proposed in Case Nos. AVU-E-11-01, AVU-E-15-05, and AVU-E-16-03 that was derived through cost of service workshops held at the Idaho Commission in February 2011 and September 2012.

Q. What do you believe are the benefits of using the system load factor to determine the peak credit ratio?

A. There are several benefits to the system load factor approach for identifying the demand-related proportion of production costs: 1) it is simple and straightforward to calculate; 2) it is directly related to the system and test year under evaluation; and 3) the relationship should remain relatively stable from year to year.

Q. What are the results of the Company's electric cost of service study presented in this case?

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[8] One minus the load factor equals the demand percentage or peak credit ratio.

A. Table No. 2 below shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates for each rate schedule:

Table No. 2:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	5.14%	0.81
General Service Schedule 11/12	9.37%	1.47
Large General Service Schedule 21/22	7.25%	1.14
Extra Large General Service Schedule 25	6.13%	0.96
Extra Large General Service Clearwater Paper Schedule 25P	6.78%	1.06
Pumping Service Schedule 31/32	5.88%	0.92
Lighting Service Schedules 41-49	6.84%	1.07
Total Idaho Electric System	6.38%	1.00

As can be observed from the above table, Residential Service Schedule 1, Extra Large General Service Schedule 25, and Pumping Service Schedules (31/32) show under-recovery of the costs to serve them. The General, Large General, Extra Large General-Clearwater Paper, and Lighting Service Schedules (11/12, 21/22, 25P, and 41-49) show over-recovery of the costs to serve them. The summary results of this study were provided to Mr. Ehrbar for consideration in the development of proposed rates.

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

A. Yes.