BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14\_\_\_\_\_\_

DIRECT TESTIMONY OF

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

##### 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 regulatory cost of service model for the Company, as well as providing support for the preparation of results of operations reports.

**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 cost of service study performed for this proceeding. Additionally, I am sponsoring the electric revenue normalization adjustments to the test year results of operations and the proposed Retail Revenue Credit rate to be used in the Energy Recovery Mechanism (ERM). A table of contents for my testimony is as follows:

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**Q. Are you sponsoring any exhibits in this case?**

A. Yes. I am sponsoring Exhibit No.\_\_ (TLK-2), which shows the calculation of the proposed Retail Revenue Credit rate. Exhibit No.\_\_ (TLK-3) includes a narrative of the electric cost of service study process, and Exhibit No.\_\_ (TLK-4) presents the electric cost of service study summary results.

**Q. Were these exhibits prepared by you or under your direction?**

A. Yes, they were.

##### II. REVENUE NORMALIZATION

##### Electric Revenue Normalization

**Q. Would you please describe the electric revenue normalization adjustments included in Company witness Ms. Andrews Attrition Study?**

A. Yes. There are three separate adjustments that normalize revenue as part of the electric Attrition Study.

1 – The Commission Basis Results of Operations in column [A] of Exhibit No. \_\_\_(EMA-2), page 4 includes a Commission Basis weather normalization adjustment. Revenues for this adjustment are based on rates that were in effect during the July 2012 through June 2013 test period.

2 – The Incremental Revenue Normalization Adjustment in column [D] of Exhibit No.\_\_\_(EMA-2), page 4 adjusts July 2012 through June 2013 test period customers and usage for any known and measurable changes, then re-prices billed, unbilled, and weather adjusted usage at the base tariff rates approved for 2013 as if the January 1, 2013 increase had been in effect for the full twelve months of the period.

3 – The 2014 Temporary Rate Increase shown in column (f) of Exhibit No.\_\_\_(EMA-2), page 1 identifies the incremental revenue produced when the normalized usage is re-priced at the base tariff rates approved for 2014.

**Q. Please begin with the first revenue normalizing adjustment in the Attrition Study. What is the Commission Basis weather normalization adjustment?**

A. Weather normalization is a required element of Commission Basis reporting pursuant to WAC 480-100-257. The intent of this adjustment is for Commission Basis adjusted revenues (and power supply costs) to reflect operations under normal temperature conditions during the reporting period.

**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 twelve months ended June 2013 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 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 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 usage per customer from January 2002 through December 2011 which is the most recent completed analysis. Autoregressive terms were included in the regressions in order to correct for autocorrelation in the data.

**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 1983 through 2012.

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

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation are consistent with the methodology presented in Docket No. UE-120436. This methodology has been used in every case and Commission Basis Report since it was introduced in Docket No. UE-070804.

**Q. What was the change in kWhs resulting from weather normalization for the twelve months ended June 2013 test year?**

A. Weather was warmer than normal from July through December of 2012, then a colder than normal January 2013 was offset by a warmer than normal February through June 2013. Since electric usage is impacted by both heating and cooling, weather normalization reductions to usage in July and August 2012 were largely offset by additions to usage September through December. Similarly, in 2013, the weather normalization reduction to usage in January was largely offset by the additions to usage in February, March and May, resulting in a very small annual adjustment. Overall, the adjustment to normal required the addition of 281 heating degree-days during the heating season[[1]](#footnote-1) and the deduction of 124 cooling degree-days during the summer season[[2]](#footnote-2). The annual total adjustment to Washington electric sales volumes was a reduction of 1,841,566 kWhs, which is approximately 0.03% of billed usage.

**Q. What was the impact of this adjustment on Commission Basis results of operations?**

A. The Commission Basis weather normalization adjustment reduced revenues by $159,000 and, after revenue-related expenses and taxes, produced a decrease to net income of $99,000. The electric system monthly weather adjustment volumes were provided to Company witness Mr. Johnson as an input to the Commission Basis Power Supply analysis.

**Q. Moving on to the second revenue normalizing adjustment in the Attrition Study. What is the purpose of the Incremental Revenue Normalization adjustment?**

A. The purpose of the “Incremental Revenue Normalization” adjustment is to restate revenue on a forward-looking basis. This is accomplished by re-pricing test year normalized billing determinants (including unbilled and weather adjustments, as well as any known and measurable changes to the test year loads and customers) to reflect revenues for the July 2012 through June 2013 test period, as if the revenue increase effective January 1, 2013 had been in effect for the full twelve months of the test period.

Base rates do not include any of the adder schedules that are included in billed revenues such as the Residential Exchange Credit Schedule 59, the Public Purpose Tariff Rider Schedule 91, and Optional Renewable Power Schedule 95[[3]](#footnote-3). Therefore the amortization expenses associated with the adder schedule revenues must be eliminated in this adjustment for proper matching of revenues and expenses.

**Q. What is the impact of the Incremental Revenue Normalization adjustment?**

A. The Incremental Revenue Normalization adjustment increases net revenue[[4]](#footnote-4) by $7,484,000 which, after revenue-related expenses and taxes, increases Washington net operating income $4,844,000, as shown in column [D] on pages 4 and 5 of Exhibit No.\_\_\_(EMA-2)[[5]](#footnote-5).

**Q. Please describe the third revenue normalizing adjustment in the Attrition Study.**

A. The “2014 Temporary Rate Increase” shown on page 1 of Exhibit No.\_\_\_(EMA-2) reflects the incremental change when the same normalized billing determinants used in the Incremental Revenue Normalization adjustment are re-priced at the base tariff rates in effect during the calendar year 2014[[6]](#footnote-6). This adjustment adds an incremental $14,054,000 of revenue over the 2013 base rates.

**Q. Are the same normalized restated revenues included in Ms. Andrews’ Pro Forma Cross Check Study shown as Exhibit No.\_\_\_(EMA-4)?**

A. Yes. The presentation in the Pro Forma Cross Check Study is slightly different because the first and second revenue normalizing adjustments discussed earlier are incorporated into one 2013 Revenue Normalization adjustment. Therefore the weather adjustment at restated rates is included with the annualization of test year revenue to 2013 base rates. The 2013 restating revenue normalization adjustment for the Pro Forma Cross Check Study increases Washington net operating income by $4,683,000, as shown in adjustment column 2.10 on page 6 of Exhibit No.\_\_\_(EMA-4). The 2014 Revenue Normalization adjustment captures the 2014 Temporary Rate Increase of $14,054,000 with an increase to Washington net operating income of $8,724,000, as shown in adjustment column 4.07 on page 10 of Exhibit No.\_\_\_(EMA-4).

**III. PROPOSED RETAIL REVENUE CREDIT RATE**

**Q. Company witness Mr. Johnson testifies that the proposed Retail Revenue Credit rate to be used in the ERM represents the energy classified portion of the fixed and variable production and transmission costs in this filing. How is that rate determined?**

A. The Retail Revenue Credit rate is determined by computing the total production and transmission related costs contained within Ms. Andrews’ Washington electric Pro Forma Cross Check Study analysis of results of operations[[7]](#footnote-7). The production/transmission-related costs are then divided by the Washington normalized retail load, in order to arrive at the average production and transmission revenue-per-kWh included in proposed rates. This value is then multiplied by the ratio of energy-classified production and transmission costs, versus total production and transmission costs, from the cost of service study, to arrive at the proposed Retail Revenue Credit rate.

**Q. Do you have an exhibit that shows the calculation of the proposed Retail Revenue Credit rate?**

A. Yes. Exhibit No. \_\_\_(TLK-2) 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 in her Pro Forma Cross Check Study analysis model. The “Pro Forma Total” at the bottom of page 1 shows the resulting production and transmission cost components.

Page 2 shows the calculation of 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. Lines 12 and 13 contain values from the cost of service study (total production and transmission amounts are the sum of column (f) lines 32 and 33 on Page 2 of Exhibit No.\_\_\_(TLK-4); the energy-classified amount is from the supporting schedule containing the functional components of line 23 on Page 3 of the same exhibit). The proposed Retail Revenue Credit rate is shown on Line 14 and represents the energy-classified portion of the average production and transmission costs per-kWh.

The proposed Retail Revenue Credit rate is $0.03360 per kWh or $33.60 per MWh as Mr. Johnson refers to it. The calculation of the Retail Revenue Credit rate will be revised based on the final revenue increase approved by the Commission in this case.

**Q. Was the same methodology used to determine the Retail Revenue Credit rate in the Company’s last general rate case?**

A. Yes. The current Retail Revenue Credit rate established in Docket No. UE-120436 was determined using this methodology.

##### IV. ELECTRIC COST OF SERVICE

**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, Pumping Service Schedule 31 and Street and Area Lighting Service Schedules 41 - 49 provide less than the overall rate of return under present rates. General Service Schedule 11 and Large General Service Schedule 21 provide more than the overall rate of return under present rates.

**Q. Please identify the Company’s electric cost studies presented to this Commission in the last five years as required by WAC 480-07-510 (6).**

A. Electric cost of service studies were presented to this Commission in Docket No. UE-080416, Docket No. UE-090134, Docket No. UE-100467, Docket No. UE-110876 and Docket No. UE-120436.

**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. Exhibit No. \_\_\_(TLK-3) 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.\_\_\_(TLK-4) is based on the twelve months ended June 30, 2013 test year Pro Forma Cross Check Study results of operations presented by Ms. Andrews in Exhibit No.\_\_\_(EMA-4). The Pro Forma Cross Check Study analysis was used for the cost of service study to provide results at the comprehensive level of detail required by the cost of service model. The Pro Forma Cross Check Study includes an adjustment that brings total expenses and rate base into agreement with the Attrition Study, therefore it provides the appropriate detailed cost basis for the cost of service study in this case.

**Q. Would you please explain the cost of service study presented in Exhibit No. \_\_\_(TLK-4)?**

A. Yes. Exhibit No. \_\_\_(TLK-4) 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.\_\_\_(TLK-3), would you please give a brief overview of the key elements and the history associated with those elements?**

A. Yes. In general, the cost study follows the methodology established in Docket No. UE-920499 for Puget Sound Power and Light (now Puget Sound Energy). Production and transmission costs are classified to energy and demand by a peak credit analysis. The definitions of “peaks” and “peak credit” specific to Avista were accepted by the Commission for Avista in Docket No. UE-991606 and confirmed in Docket No. UE-050482. As I will discuss later in my testimony, the electric cost of service study presented in this case includes a revision to the Avista-specific peak credit analysis.

Distribution costs are classified and allocated by the basic customer theory[[8]](#footnote-8) that was derived directly from the methodology approved for Puget in Docket No. UE-920499. Administrative and general costs are first directly assigned to production, transmission, distribution, or customer relations functions. The Commission found this process acceptable in Avista’s Docket No. UE-991606. The remaining administrative and general costs are categorized as common costs and have been allocated by a variety of factors as approved by this Commission for Puget in Docket No. UE-920499. The specific factors and items they are applied to are described in detail in Exhibit No. \_\_\_(TLK-3) on page 5 and listed by account on page 9.

**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 Washington?**

A. Yes. The methodology presented in this case is the same as that used in the studies presented in Docket Nos. UE-120436 and UE-110876.

**Q. You mentioned a revision to the Avista-specific peak credit analysis accepted by the Commission in 2005. Has Avista proposed the same revision in recent cases?**

A. Yes. In developing its cost of service study in Docket No. UE-100467, the Company examined the Avista-specific peak credit classification methodology applied to production and transmission functional costs. It was determined that the prior methodology was complicated to compute and apply, unrelated to the actual usage of the system, and has a tendency to shift costs back and forth between energy and demand with changes in the cost of natural gas to fuel combustion turbines. The peak credit method proposed by Avista in that Docket provided a less complex way to determine a fair apportionment of production and transmission costs between energy and demand, is directly related to our electrical system, and is expected to be stable both during the pendency of a case and over time from case to case.

While a revision to the peak credit classification of production and transmission costs was proposed in both Docket No. UE-100467 and Docket No. UE-110876, the cost of service methodology change was specifically not part of the settlements in either case. In Docket No. UE-120436, while Commission staff provided testimony supportive of the Company’s load factor based peak credit methodology, and no other parties addressed it, the revision to the electric cost of service methodology was not mentioned at all in the settlement or the Commission Order. Therefore the “Prior Methodology” continues to refer to the study methodology last presented in Docket No. UE-090134.

**Q. How was the prior peak credit methodology determined and applied?**

A. In the Company’s cost of service studies prior to 2010, Avista’s electric system resource costs were classified to energy and demand using a comparison of the replacement cost per kW of the Company’s peaking units to the replacement cost per kW of the Company’s thermal and hydro plants (separately). This analysis created separate peak credit ratios applied to thermal plant and hydro plant. Transmission costs were assigned to energy and demand by a 50/50 weighting of the thermal and hydro peak credit ratios. Fuel and load dispatching expenses were classified entirely to energy, and peaking plant related costs were classified entirely to demand.

**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.[[9]](#footnote-9) This single peak credit ratio is then applied uniformly to all production costs. This is the same method the Company proposed in its recent rate filings, as discussed earlier.

In Washington, transmission costs have traditionally been treated as an extension of the generation system, therefore, the revised peak credit ratio has also been applied to transmission costs in this study.

**Q. What 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 is the net effect of the proposed change in the peak credit method?**

A. The net effect of this change is to slightly decrease the overall production and transmission costs that are classified as demand-related. Using the prior method, approximately 32.57% of total production and transmission costs (31% of total production costs and 42% of total transmission costs) were classified as demand-related. Under the proposed method, 31.27% of total production and transmission costs are classified as demand-related. In this circumstance, costs are shifted away from the low load factor residential class, and to all the other classes, but the difference is very minor.

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

A. The following table 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. 1



As can be observed from the above table, Residential service Schedule 1 shows significant under-recovery of the costs to serve them. The Extra Large General service Schedule 25, the Pumping service schedule (31/32) and the Lighting service schedules (41-49) all show moderate under-recovery. However, the General and Large General service schedules (11/12 and 21/22) show significant 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.

1. The heating season includes the months of January through June and October through December. [↑](#footnote-ref-1)
2. 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. [↑](#footnote-ref-2)
3. City Business and Occupation Taxes (Schedule 58) and Energy Recovery Mechanism (Schedule 93) revenues and expenses are eliminated in separate Commission Basis adjustments. [↑](#footnote-ref-3)
4. Net revenue refers to the change in revenue less the change in expense associated with the eliminated adder schedule revenue. [↑](#footnote-ref-4)
5. Ms. Andrews explains the rate base adjustments shown in this column, which are unrelated to this revenue normalization adjustment. [↑](#footnote-ref-5)
6. Docket No. UE-120436 base rates effective 1/1/2014 – 12/31/2014. [↑](#footnote-ref-6)
7. The proposed revenue increase in this case is based on the Attrition Study. However, components from the Pro Forma Cross Check Study analysis are used for both the Retail Revenue Credit rate and the Cost of Service study in order to have the level of detail necessary to properly functionalize the costs. The Pro Forma Cross Check Study analysis includes an adjustment that brings total expenses and rate base into agreement with the attrition study. [↑](#footnote-ref-7)
8. Basic customer theory classifies only meters, services and street lights as customer-related plant; all other distribution facilities are considered demand-related. [↑](#footnote-ref-8)
9. One minus the load factor equals the demand percentage or peak credit ratio. [↑](#footnote-ref-9)