Exh. TLK-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-19_____

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 the Manager of Regulatory Accounting Initiatives in the Regulatory Affairs 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 revenue normalization adjustments and the electric cost of service study performed for this proceeding. 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 Exh. TLK-2 which includes a narrative of the electric cost of service study process, and Exh. TLK-3 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. SUMMARY

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 Schedules 01/02 and Pumping Service Schedules 30/31/32 provide less than the overall rate of return under present rates. General Service Schedules 11/12, Large General Service Schedules 21/22, Extra Large General Service Schedule 25 and Street and Area Lighting Service Schedules 41 - 48 provide more than the overall rate of return under present rates. Table No. 1 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. 1 – Relative Rates of Return at Present Rates

Customer Class	Rate of Return	Return Ratio
Residential Service Schedules 01/02	2.36%	0.43
General Service Schedules 11/12	12.29%	2.24
Large General Service Schedules 21/22	8.51%	1.55
Extra Large General Service Schedule 25	5.93%	1.08
Pumping Service Schedules 31/32	4.68%	0.85
Lighting Service Schedules 41 - 48	6.25%	1.14
Total Washington Electric System	5.50%	1.00

Notably, the residential rate schedules (Schedules 01/02) and general service rate schedules (Schedules 11/12) are considerably further from unity in the cost study than the other rate schedules.

III. ELECTRIC REVENUE NORMALIZATION

Q. Would you please describe the electric revenue normalization adjustments included in Company witness Ms. Andrews' Revenue Requirement Study?

A. Yes. Similar to the natural gas revenue normalization adjustment, sponsored by Company witness Mr. Miller, there are three separate adjustments that normalize revenue as part of the electric revenue normalization adjustment:

1. Weather Normalization: Column 2.10 of Ms. Andrews' Exh. EMA-2, page 6 is a Commission Basis weather normalization restating adjustment. Revenues for this adjustment are based on rates that were in effect during the January 2018 through December

2018 test period, and kWh sales and revenues have been adjusted to reflect normal weather conditions. The weather-related revenues associated with the Company's electric Decoupling Mechanism are removed in this adjustment, as kWh sales and revenues have been normalized to reflect normal weather conditions.

2. Eliminate Adder Schedules: In addition to the weather normalization adjustment, Ms. Andrews' study also includes an Eliminate Adder Schedules restating adjustment in column 2.11 of Exh. EMA-2, page 6, which removes the impact of adder schedule revenues and related expenses during the January 2018 through December 2018 test period. Decoupling contra-revenues recorded in the test year associated with financial reporting revenue recognition limits on deferred revenue mechanisms are also eliminated in this adjustment for Commission Basis reporting purposes.

3. Pro Forma Revenue: The Pro Forma Revenue Normalization Adjustment in column 3.01 of Exh. EMA-2, page 8, adjusts January 2018 through December 2018 test period customers and usage for any known and measurable (pro forma) changes. In addition, the adjustment re-prices billed, unbilled, and weather adjusted usage at the base tariff rates approved in 2018, as if the May 1, 2018 base tariff rates were effective for the full 12-months of the test year.[1]

Weather Normalization

Q. Please begin with the first revenue normalizing adjustment, what is the Commission Basis weather normalization adjustment?

[1] Docket No. UE-170485.

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 12-months ended December 2018 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 multiplied by the monthly test period number of customers, which is then multiplied by the difference between normal heating/cooling degree-days and actual heating/cooling degree-days. This calculation produces the change in kWh usage required to adjust existing loads to the amount expected if weather had been normal.

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 2007 through December 2016 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 1989 through 2018.

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-170485. 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 12-months ended December 2018 test year?

A. Weather was warmer than normal most of the test year. Since electric usage is impacted by both heating and cooling, weather normalization required an increase to usage for warm weather during the winter months that was offset by a reduction to usage for some colder than normal spring months and hot summer months. Overall, the adjustment to normal required the addition of 447 heating degree-days during the heating season[2] and the

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

reduction of 78 cooling degree-days during the summer season.[3] The annual total adjustment to Washington electric sales volumes was an addition of 29,571,094 kWhs, which is approximately 0.5% of billed usage.

Q. What was the impact of this adjustment on restated results of operations?

A. The Commission Basis weather normalization adjustment increased total electric revenues by $2,745,000. The combined effect of netting the increase to revenue against the decoupling revenue offset of ($2,110,000), resulted in net weather adjustment revenue of $635,000.[4] After an offsetting reduction for revenue-related expenses and taxes, the weather normalization adjustment produced an increase to net operating income of $406,000, as shown below:

Illustration 1: - Summarize Weather Normalization Adjustment

General Business Revenue (Sales)	$2,745,000
Other Revenue (Decoupling Deferred)	($2,110,000)
Total Revenue (Net Adjustment)	$635,000
Less: Revenue Related Expenses	($121,000)
Less: Income Tax Expense	($108,000)
Net Operating Income	$406,000

The cost of the weather-related load change is reflected in the "Authorized Power Supply" adjustment in column 2.18 (page 7, Exh. EMA-2). This power supply adjustment also captures the test period load difference from the retail load included in the Energy Recovery Mechanism (ERM) base approved by Docket No. UE-170485. Both the difference from authorized to actual 2018 loads and the weather normalization adjustment to

[3] The summer season normally 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. May was also adjusted for cooling in 2018 as the month was extraordinarily warm.

[4] The Decoupling Mechanism went into effect January 1, 2015.

loads are multiplied by the ERM Retail Revenue Adjustment Rate then added to the May 1, 2018 ERM base costs. This process matches power supply costs with the power supply revenue per kWh embedded in present rates thereby maintaining the present authorized ERM base in this case.

<u>Eliminate Adder Schedules</u>

Q. Moving on to the <u>second revenue normalizing</u> adjustment, what is the purpose of the Eliminate Adder Schedules restating adjustment?

A. The Eliminate Adder Schedules adjustment removes both the revenues and expenses associated with all adder schedule rates not accounted for in other adjustments. These items are recovered/rebated by separate tariffs and therefore are not part of base rates. The items eliminated from the test year include: Schedule 59 Residential Exchange credit, Schedule 74 Tax Reform Temporary rebate, Schedule 75 Decoupling rate adjustment, Schedule 89 Fixed-Income Senior and Disabled Residential Service Discount rate adjustment, Schedule 91 Demand Side Management rate adjustment, Schedule 92, Low Income Rate Assistance Program rate adjustment, the unbilled portion of Schedule 93 Energy Recovery Mechanism rate adjustment, Schedule 95 Optional Renewable Power rate, and the unbilled portion of Schedule 98 Renewable Energy Credit Revenue Mechanism credit.

Decoupling contra-revenues recorded in the test year associated with financial reporting revenue recognition limits on deferred revenue mechanisms are also eliminated in this adjustment for Commission Basis reporting purposes.

Q. What was the impact of the Eliminate Adder Schedule adjustment on restated results of operations?

A. The Eliminate Adder Schedule adjustment results in an equal and offsetting reduction to both revenue and expense and has no impact on net income unless contra-decoupling entries were recorded in the test year. For the 2018 test year, an electric contra-decoupling entry reduced revenue $1,396,000. Elimination of this entry increased net income $1,103,000.

The billed portion of Schedules 93 and 98 are eliminated in the Eliminate WA Power Cost Deferral adjustment 2.15 on page 7 of Exh. EMA-2, and Schedule 58 Municipal Tax Adjustment is eliminated in the Eliminate B&O Taxes adjustment 2.01 on page 5 of Exh. EMA-2. After these adjustments the Restated Total General Business revenue (column R-Ttl on page 7 of Exh. EMA-2) represents weather normalized <u>base</u> rate revenue received during the 12-months ended December 31, 2018 test period (including decoupling deferred revenue not explained by weather).

<u>Pro Forma Revenue</u>

Q. Please describe the purpose of <u>third revenue normalizing</u> adjustment, the Pro Forma Revenue Normalization adjustment.

A. The purpose of the Pro Forma Revenue Normalization adjustment (3.01) 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 January 2018 through December 2018 test period, as if the base tariff rates approved in

Docket No. UE-170485 effective May 1, 2018 had been in effect for the full 12 months of the test period.[5]

Q. What is the impact of the Pro Forma Revenue Normalization adjustment?

A. The Pro Forma Revenue Normalization adjustment increases general business revenue by $3,949,000. The combined effect of the increase to revenue from rates with elimination of both the 2018 restated decoupling deferred revenue of (-$13,186,000) and the Tax Reform provision for rate refund booked January through April 2018 (+$8,155,000), resulted in a total pro forma revenue adjustment decrease of $1,082,000. After an offset for revenue-related expenses and taxes, Washington net operating income decreased $993,000, as shown below and in column 3.01 on page 8 of Exh. EMA-2.

Illustration 2 – Summarize Revenue Normalization Adjustment

General Business Revenue (Sales)	$3,949,000
Other Revenue (Eliminate Decoupling Deferred)	($13,186,000)
Other Revenue (Eliminate Provision for Refund)	$8,155,000
Total Revenue (Net Adjustment)	($1,082,000)
Less: Revenue Related Expenses	($175,000)
Less: Income Tax Expense	$264,000
Net Operating Income	($993,000)

IV. ELECTRIC COST OF SERVICE

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).

[5] The Pro Forma Normalized Revenue does not include any pro formed decoupling deferred revenue. The decoupling base will be updated with the rates approved for this case based on the same usage and customers used to determine revenue from present rates in this adjustment.

A. Electric cost of service studies were presented to this Commission in Docket No. UE-120436, Docket No. UE-140188 Docket No. UE-150204, Docket No. UE-160228 and Docket No. UE-170485.

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. Exh. TLK-2 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 Exh. TLK-3 is based on the 12-months ended December 2018 test year pro forma results of operations presented by Company witness Ms. Andrews as Exh. EMA-2.

Q. Would you please explain the cost of service study presented in Exh. TLK-3?

A. Yes. Exh. TLK-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 Mr. Miller 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. Does the Electric Base Case cost of service study utilize the same methodology from the Company's last electric case in Washington?

A. Yes, the Base Case cost of service study was prepared using the same methodology applied to the study presented in Docket No. UE-170485 (also presented in Docket Nos. UE-160228, UE-150204, UE-140188, UE-120436). The Company is cognizant that there is an ongoing cost of service docket underway that is analyzing many aspects of how parties conduct cost of service studies. It is the Company's belief that no major cost of service methodology changes should occur until after the culmination of those proceedings.

Q. Given that the specific details of this methodology are described in the narrative in Exh. TLK-2, 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 into energy-related and demand-related 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.

Distribution costs are classified and allocated by the basic customer theory[6] 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, and 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 Exh. TLK-2 on page 5 and listed by account on page 9.

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

Q. What peak credit methodology did the Company use in this case?

A. In this case the Company used the system load factor to determine the proportion of the production function that is demand-related.[7] This single peak credit ratio is then applied uniformly to all production costs. In Washington, transmission costs have traditionally been treated as an extension of the generation system, therefore, the 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 are the results in this case using the system load factor peak credit methodology?

A. Under the system load factor peak credit methodology, 39.52% of total production and transmission costs are classified as demand-related, and 60.48% are classified as energy-related.

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

A. Table No. 2 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:

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

Table No. 2 – Electric Cost of Service Base Case Results

Customer Class	Rate of Return	Return Ratio
Residential Service Schedules 01/02	2.36%	0.43
General Service Schedules 11/12	12.29%	2.24
Large General Service Schedules 21/22	8.51%	1.55
Extra Large General Service Schedule 25	5.93%	1.08
Pumping Service Schedules 30/31/32	4.68%	0.85
Lighting Service Schedules 41 - 48	6.25%	1.14
Total Washington Electric System	5.50%	1.00

As can be observed from the above table, Residential service Schedules 01/02 and Pumping service Schedules 30/31/32 show under-recovery of the costs to serve them. The Extra Large General service Schedule 25 and the Street and Area Lighting service Schedules 41-48 are slightly over unity with the overall return from present rates. However, the General and Large General service Schedules 11/12 and 21/22, respectively, show over-recovery of the costs to serve them (currently providing in excess of the requested rate of return). Notably, the residential rate schedules (Schedules 01/02) and general service rate schedules (Schedules 11/12) are considerably further from unity in the cost study than the other rate schedules. The summary results of this study were provided to Mr. Miller for consideration in the development of proposed rates.

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

A. Yes.