DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL OF
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

RECEIVED
2010 MAR 23 AM 11:17
IDAHO PUBLIC
UTILITIES COMMISSION

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-10-01 CASE NO. AVU-G-10-01 DIRECT TESTIMONY OF TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

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. I am responsible for preparing the regulatory cost of service models for the Company, as well as providing support for the preparation of results of operations reports.

Q. Would you describe your educational background and professional experience?

A. Yes. 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 have also been 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 these proceedings?

A. My testimony and exhibits will cover the Company's electric and natural gas cost of service studies performed for this proceeding. Additionally, I am sponsoring the electric and natural gas revenue normalization adjustments to the test year results of operations and the proposed retail revenue credit rate to be used in the Power Cost Adjustment mechanism. I will also provide an overview of the electric load research study that was recently completed by the Company. A table of contents for my testimony is as follows:

<u>Table of Contents</u>	**<u>Page</u>**

Q. Are you sponsoring any Exhibits with your pre-filed testimony?

A. Yes. I am sponsoring Exhibit No. 13 composed of six schedules as follows: Schedule 1, retail revenue credit rate calculation; Schedule 2, electric cost of service study process description; Schedule 3, electric cost of service study summary results; Schedule 4, load research study report; Schedule 5, natural gas cost of service study process description; and Schedule 6, natural gas cost of service 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 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 twelve months ended December 2009 test period and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $3,620,000, as shown in column (z) on page 6 of Ms. Andrews Exhibit No.12, Schedule 1. The revenue normalization adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) at present base tariff rates in effect, 2) adjusting customer loads and revenue to a 12-month calendar basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue[1].

Q. Since these three elements are combined into a single adjustment, would you please identify the impact (before taxes and revenue related expenses) of each component?

A. Yes. The re-pricing of billed usage comprises the majority of the change in test year revenue. The combined impact of the rate increase effective August 1, 2009 and the elimination of revenue and amortization expense from adder schedules (Schedule 59 Residential Exchange, and Schedule 91 Public Purpose Tariff Rider[2]) is an increase of $9,302,000. Revenue from unbilled calendar usage compared to the amount included in results of operations is a reduction of $134,000[3]. Finally, the weather normalization adjustment reduces revenue by $3,497,000. The combined impact of these elements is an increase of $5,671,000 which, after revenue-related expenses and income taxes, results in the increase to net operating income of $3,620,000.

---

[1] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.
[2] City Franchise Fee and Power Cost Adjustment revenues are eliminated in separate adjustments.
[3] The unbilled adjustment consists of removing December 2008 usage billed in January 2009 from the 2009 test year, adding December 2009 usage billed in January 2010 to the 2009 test year, and re-pricing the net adjustment to usage at the base rates presently in effect.

Q. Would you please briefly discuss electric weather normalization?

A. Yes. The Company's weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the twelve months ended December 2009 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 five 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. No. Regression analysis was performed on 2004 through 2008 billing data which resulted in higher sensitivity factors. Use of these higher sensitivity factors would have resulted in a greater reduction in usage which in turn would have increased the current rate request. In an effort to present a conservative estimate of the impact of abnormal weather during 2009 (beneficial to customers), the Company elected to stay with the previous factors.

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.

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

A. Yes.

Q. What was the impact of electric weather normalization on the twelve months ended December 2009 test year?

A. Weather was colder than normal during the winter and spring, and warmer than normal during the summer of 2009. The adjustment to normal required the deduction of 430 heating degree-days during the heating season[4] and 155

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

cooling degree-days. The total adjustment to Idaho sales volumes was a reduction of 44,832,283 kWhs which is approximately 1.3 percent of billed usage.

Natural Gas Revenue Normalization

Q. Would you please describe the natural gas revenue adjustment included in Ms. Andrews pro forma results of operations?

A. Yes. The natural gas revenue normalization adjustment is similar to the electric adjustment and represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2009 test period and retail revenues on a normalized (pro forma) basis. The adjustment includes the re-pricing of pro forma sales and transportation volumes at present rates (effective November 1, 2009) using pro forma sales volumes that have been adjusted for unbilled sales, abnormal weather, and any material customer load or schedule changes. The rates used exclude: 1) Temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization rate for deferred gas costs approved in the Company's last PGA filing and 2) Public Purposes Rider Adjustment Schedule 191[5].

Q. Does the Revenue Normalization Adjustment contain a component reflecting normalized gas costs?

[5] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

A. Yes. Purchase gas costs are normalized using the gas costs approved by the Commission in Case No. AVU-G-09-05, the Company's 2009 PGA filing, as set forth under Schedule 150. Those gas costs are then applied to the pro forma retail sales volumes so that there is a matching of revenues and gas costs.

The total net amount of the natural gas revenue normalization, which includes the purchase gas cost adjustment, is a decrease to net operating income of $537,000, as shown in column (h), page 6 of Ms. Andrews Exhibit No.12, Schedule 2.

Q. Would you please briefly discuss natural gas weather normalization?

A. Yes. The natural gas weather adjustment is developed from a regression analysis of ten years of billed usage-per-customer and billing period heating degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating degree-day) are applied to monthly test period customers and the difference between normal heating degree-days and monthly test period observed heating degree-days. This calculation produces the change in therm usage required to adjust existing loads to the amount expected if weather had been normal.

Q. In your discussion of electric weather normalization you indicated that the adjustment utilized

sensitivity factors from the last case. Is this true for natural gas as well?

A. Yes. Once again, in an effort to present a more conservative reduction to usage due to abnormal weather, the factors from the last case were used instead of updated factors which indicated slightly higher sensitivity.

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

A. Normal heating degree-days are based on a rolling 30-year average of heating 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 data dropping off, thereby reflecting the most recent information available at the end of each calendar year.

Q. Is the 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 are consistent with the methodology presented in Case No. AVU-G-09-01.

Q. What was the impact of natural gas weather normalization on the twelve months ended December 2009 test year?

A. Weather was colder than normal during the 2009 winter and spring months. The adjustment to normal required the deduction of 430 heating degree-days from January through June and October through December.[6] The adjustment to sales volumes was a reduction of 3,762,074 therms which is approximately three percent of billed usage. The margin impact (revenue less gas cost) of the weather adjustment was a reduction of $1,187,000.

III. PROPOSED ELECTRIC RETAIL REVENUE CREDIT RATE

Q. Company witness Mr. Johnson indicates that the retail revenue credit rate to be used in the Power Cost Adjustment (PCA) represents the average cost of production and transmission in this filing. How is that rate determined?

A. The retail revenue credit rate is determined by computing the proposed revenue requirement on the 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 proposed rates.

[6] Warmer than normal weather that occurred during July through September did not impact the natural gas weather normalization adjustment as the seasonal sensitivity factor is zero for summer months.

Q. Do you have an exhibit that shows the calculation of the proposed retail revenue credit rate?

A. Yes. Exhibit No. 13, 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 "Pro Forma Total" 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 to the revenue normalization adjustment. The proposed retail revenue credit rate is shown on Line 11 and represents the average production and transmission cost-per-kWh proposed to be embedded in Idaho customer retail rates.

The proposed retail revenue credit rate is $0.05026 per kWh or $50.26 per mWh. The calculation of the retail revenue credit rate will be revised based on the final production and transmission costs and rate of return that are approved by the Commission in this case.

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 and 25P, and Pumping Service Schedule 31 provide less than the overall rate of return under present rates. General Service Schedule 11, Large General Service Schedule 21 and Street and Area Lighting Service provide more than the overall rate of return under present rates.

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 in relation to each group's characteristics, 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. 13, Schedule 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 Exhibit No.13, Schedule 3 is based on the twelve months ended December 2009 test year pro forma results of operations presented by Company witness Ms. Andrews in Exhibit No.12, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 13, Schedule 3?

A. Yes. Exhibit No. 13, 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 Mr. Ehrbar for his work on 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. 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 hard copy in the workpapers accompanying this case.

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

A. Only in part. The methodology applied to distribution and administrative and general costs has not changed from the methodology accepted by the Idaho Commission in Case No. AVU-E-04-01 and subsequently presented in AVU-E-08-01 and AVU-E-09-01. However, the

Company <u>is</u> proposing a revision to the peak credit classification for production costs and a change to the methodology applied to transmission costs in this case.

Q. With respect to the components that have not changed (given that the specific details of this methodology are described in Exhibit No. 13, Schedule 2), would you please give a brief overview of the key elements and the history associated with those elements?

A. Yes. Distribution costs are classified and allocated by the basic customer theory[7] accepted by the Idaho commission in Case No. WWP-E-98-11. 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. Moving on to components of the study that have changed, let's start with production costs. You said the

[7] Basic customer theory classifies only meters, services and the direct assignment of street light fixtures as customer-related plant; all other distribution facilities are considered demand-related.

Company is proposing a revision to the peak credit classification for production cost. Please explain.

A. In addition to preparing a new load study, the Company also decided to examine the operating characteristics, and associated costs, of its electric system resources in conjunction with the allocation of costs within its cost of service study. Traditionally, both production and transmission costs have been classified into energy-related and demand-related components by the peak credit ratio method. Therefore the "peak credit" classification methodology was evaluated to determine whether it was appropriate to make any changes, given our current electric system characteristics.

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

A. In the Company's prior cost of service studies, 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 with regard to the peak credit methodology and how was it developed?

A. Energy Resources Department personnel were enlisted to examine the issue. The result of their analysis is reflected in Company witness Mr. Kalich's recommended revised peak credit classification ratio of 38.1% applied uniformly to all production costs. As explained by Mr. Kalich, the peak credit ratio (the proportion of total production cost that is capacity-related) is determined using the operational model of the incremental capacity resource detailed in the Company's latest Integrated Resource Plan. The ratio of the costs remaining after dispatch into the wholesale marketplace relative to the entire cost of the incremental resource is the share of production costs attributable to demand.

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

A. The net effect of this change is to increase the overall production costs that are classified as demand-related. Using the prior method, approximately 26% of total production costs were classified as demand-related, compared to 38.1% under the revised method. This change shifts costs away from high load factor customer groups as well as customer groups which have a limited contribution to system peak usage (pumping and street lighting).

Q. Moving on to transmission, you mentioned the Company is proposing "a change to the methodology applied to transmission costs". What are you changing and why?

A. The proposed method applied in the Base Case cost of service study incorporates changes to both the classification and allocation of transmission costs. These changes resulted from examining the issues raised by the intervening parties in Case No. AVU-E-09-01. In fact, as part of the Settlement Agreement in Case No. AVU-E-09-01, the Company agreed to the following:

> As part of its next general rate case (GRC), the Company will prepare an analysis of the impacts of allocating 100% of transmission costs to demand, as well as allocating transmission costs to reflect any peak and off-peak seasonal cost differences over seven months, rather than assuming an equal weighting over twelve months. (page 11).

Q. How did you change the classification of transmission costs?

A. Historically, Avista has included transmission costs in the production peak credit classification. It has been done this way largely because it is the accepted process in Washington, even though, as the interveners pointed out, 100% demand is the more universally accepted classification of transmission costs in other states (including the other investor-owned utilities in Idaho).

In the Base Case cost of service study in this case, all transmission costs have been classified as demand-related.

Q. Did you make any further changes to the allocation of transmission costs?

A. Yes. In prior studies, demand-related transmission costs have been allocated to customer groups by their contributions to the average of the twelve monthly system coincident peaks. In this study, only the system coincident peaks occurring in 4 winter months and 3 summer months were included in the average. The rationale behind this allocation is that the lower customer demands in the off-peak fall and spring seasons do not impose the same capacity utilization of the transmission facilities as the high demand winter and summer seasons.

Q. The Settlement Agreement only required the Company to prepare an analysis of the impact of these two issues. Why did you include them in the Base Case cost of service study?

A. There are reasonable arguments supporting both of these changes, some of which are identified above. In addition, these changes reduce cost allocation to high load factor customers. Since the last test year, we have seen the number of Schedule 25 Extra Large General Service customers reduced by one-third, as the forest industry in particular continues to experience financial difficulties.

Choosing acceptable methodologies that can legitimately reduce cost pressure for this group of customers represents a conscious effort to help keep this segment in business.

Q. What are the results of the Company's Base Case cost of service study?

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:

Illustration 1:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	4.06%	0.78
General Service Schedule 11	8.68%	1.67
Large General Service Schedule 21	6.47%	1.25
Extra Large General Service Schedule 25	2.72%	0.53
Ex. Lg. Gen. Svc. Clearwater Paper Schedule 25P	4.47%	0.86
Pumping Service Schedule 31	4.55%	0.88
Lighting Service Schedules 41 - 49	6.30%	1.21
Total Idaho Electric System	5.19%	1.00

As can be observed from the above table, residential, extra large general service, and pumping service schedules (1, 25, 25P, and 31) show under-recovery of the costs to serve them, while the general, large general, and lighting service schedules (11, 21, and 41 - 49) show over-recovery of the costs to serve them. The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. Can you illustrate how the changes to the methodology applied to production and transmission costs impacted the cost of service study results?

A. Yes. The following table contains the progression in the relative return ratio from the model run of the study using the prior method to the proposed Base Case method.

Illustration 2:

Customer Class	Prior Method	Step 1 Revised Peak Credit	Step 2 Revised Peak Credit and Transmission 100% Demand	Base Case Revised Peak Credit Transmission 100% Demand & 7CP
Schedule 1	0.87	0.83	0.80	0.78
Schedule 11	1.72	1.70	1.67	1.67
Schedule 21	1.25	1.24	1.24	1.25
Schedule 25	0.46	0.49	0.51	0.53
Schedule 25P	0.59	0.74	0.83	0.86
Schedule 31	0.79	0.83	0.85	0.88
Schedules 41-49	1.12	1.17	1.21	1.21
Total Idaho	1.00	1.00	1.00	1.00

This illustration shows the impact of each incremental change to the electric cost of service methodology.

Demand Study

Q. An issue was raised in Case No. AVU-E-08-01 regarding the load data used to develop demand allocations

in the electric cost of service. Please elaborate on this issue.

A. In the Company's 2008 general rate case, the Company indicated that, while the estimation process used to create the demand allocators in the cost of service study provides a reasonable assignment of cost to the existing customer groups, the Company's load data was in the process of being updated. Accordingly, the Commission provided the following directive on page 13 of its Order No. 30647:

> In this case the Commission finds the Company-filed cost of service study to be sufficient to determine rate design in this case. We direct the Company in its next general rate case to provide updated load data as part of its COS study or, in the alternative, show how the lack of such an update affects COS-based revenue allocations to customer classes.

Q. How was this issue treated in the Company's 2009 general rate case?

A. The load study was in progress during the pendency of Case No. AVU-E-09-01. Even though the Company presented sensitivity analysis to illustrate the potential impact of updated load information on cost of service based revenue allocations, the parties ultimately agreed to spread the increase in electric base revenue on a uniform percentage basis. The Company also agreed as part of the approved settlement to share the results of the load study as soon as it became available. This contingency was meant to assure the parties that if another case had been filed before the load study had been completed, the results could be considered during the case as soon as they did become available.

Q. Has Avista incorporated current load research into the cost-of-service study presented for this case?

A. Yes. The Company designed and implemented a load research study in 2009. The results of that study were applied within the Company's cost-of-service study.

Q. How does the load research influence the cost-of-service study?

A. Many of the components of a cost-of-service study are distributed among the various rate classes based upon the energy use and demand of that customer class during different time periods. A load research study is a measurement of a statistically valid sample of each customer class used to estimate how that customer class contributes to the overall system load. Those contributions then become part of the cost-of-service study.

Q. How was this load study performed?

A. In 2008, Avista reviewed the tasks necessary for the design and implementation of a long-term load research study that would deliver usable results based upon one full