Exhibit No. ___(TLK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-10______

DOCKET NO. UG-10______

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 regulatory cost of service models 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 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 this proceeding?

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 Energy Recovery 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:

Table of Contents **Page**

		Page
I.	Introduction	1
II.	Revenue Normalization	3
	Electric	3
	Natural Gas	6
III.	Proposed Retail Revenue Credit Rate	8
IV.	Electric Cost of Service	10
	Table 1 Base Case Results	15
	Demand Study	16
V.	Natural Gas Cost of Service	19
	Table 2 Base Case Results	22

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit No.__ (TLK-2), the proposed retail revenue credit rate calculation. Related to the electric cost of service study, I am sponsoring Exhibit No.__ (TLK-3), the electric cost of service study process description; Exhibit No.__ (TLK-4), the electric cost of service study summary results; and Exhibit No.__ (TLK-5), the load research study report.

Finally, related to the natural gas cost of service study, I am sponsoring Exhibit No.__ (TLK-6), the natural gas cost of service study process description; and Exhibit No.__ (TLK-7), the natural gas 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 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 Washington net operating income by $3,882,000, as shown in column (AD) on page 9 of Exhibit No.___(EMA-2). The revenue normalization adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) at base tariff rates presently 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 January 1, 2010, 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 in net revenue of $15,728,000. Revenue from unbilled calendar usage compared to the amount included in results

[1] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.
[2] City Business and Occupation Taxes and Energy Recovery Mechanism revenues are eliminated in separate adjustments.

of operations results in a reduction of $3,557,000[3]. Finally, the weather normalization adjustment reduces revenue by $6,624,000. The combined impact of these elements is an increase of $5,547,000 which, after revenue-related expenses and income tax, results in the increase to net operating income of $3,882,000.

Q. Would you please briefly discuss electric weather normalization?

A. Yes. The Company's electric 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 ten years of billed usage per customer and billing period heating and cooling degree-day data[4]. 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 1999 through 2008 billing data which resulted in higher sensitivity factors. Use of these higher sensitivity factors would have resulted

[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 January 1, 2010 rates.

[4] Ten years of data was used for all customer groups except Residential Schedule 21. The results for this customer group did not meet the statistical criteria with 10 years of data, but did with 5 years, therefore the group was kept in the weather adjustment with the 5 year regression result.

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 Washington?

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[5] and 155 cooling degree-days. The total adjustment to Washington sales volumes was a reduction of 84,033,763 kWhs which is approximately 1.5% of billed usage.

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

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 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, 2) Public Purposes Rider Adjustment Schedule 191, and 3) Natural Gas Decoupling Rate Adjustment Schedule 159[6].

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

A. Yes. Purchase gas costs are normalized using the gas costs approved by the Commission in Docket No. UG-091462, the Company's 2009 PGA filing, as set forth under Schedule 156. Those gas costs are then applied to the pro forma retail sales volumes so that there is a matching of revenues and gas costs.

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

The total net amount of the natural gas revenue normalization, which includes the purchase gas cost normalization, is a decrease to net operating income of $395,000, as shown in column (H), page 6 of Exhibit No. ___(EMA-3).

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

A. Yes. The natural gas weather normalization 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 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 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. UG-090135.

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.[7] The adjustment to sales volumes was a reduction of 8,958,536 therms which is approximately 3.6 percent of billed usage. The margin impact (revenue less gas cost) of the weather adjustment was a reduction of $2,280,000.

III. PROPOSED RETAIL REVENUE CREDIT RATE

Q. Company witness Mr. Johnson indicates that the retail revenue credit rate to be used in the ERM 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' Washington electric pro forma total results of operations. The production/transmission revenue requirement amount is then divided by the Washington normalized retail load used to set rates in

[7] 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.

order to arrive at the average production and transmission cost-per-kWh embedded in proposed rates.

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. The "Pro Forma Total Production and Transmission Costs" 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. 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 Washington customer retail rates.

The proposed retail revenue credit rate is $0.05280 per kWh or $52.80 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 Pumping Service Schedule 31 provide substantially less than the overall rate of return under present rates. General Service Schedule 11, Large General Service Schedule 21 and Street and Area Lights provide more than the overall rate of return under present rates. In fact, the study shows that General Service Schedule 11 is currently providing a rate of return more than two times the current overall rate of return for WA electric 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).

A. Electric cost of service studies were presented to this Commission in Docket No. UE-050482, Docket No. UE-070804, Docket No. UE-080416, and Docket No. UE-090134.

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 December 2009 test year pro forma results of operations presented by Ms. Andrews in Exhibit No.___(EMA-2).

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 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 in hard copy in the workpapers accompanying this case.

Q. Given that the specific details of this methodology are described 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 definition of "peaks" and "peak credit" specific to Avista have been 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] 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

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

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 pages 5 and 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. In most respects, yes. The Base Case cost of service study was prepared using the methodology applied to the study presented in Docket No. UE-090134 <u>except</u> that the <u>peak credit</u> classification of production and transmission costs has been revised.

Q. Why is the Company proposing to revise the method for classifying production and transmission costs into energy-related and demand-related components?

A. In the settlement agreement in Docket No. UE-070804, the Company agreed that, in addition to preparing a new load study, "the Company will further 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." (Partial Settlement Stipulation, at pages 3-4). Since electric system resources have traditionally been subject to an Avista-specific peak credit analysis within the cost of service study, compliance with this settlement requirement led to examination of our "peak credit" classification methodology.

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.

In Washington, transmission costs have 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 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 and transmission costs that are classified as demand-related. Using the prior method, approximately 24% of total production costs and 36% of total transmission 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 (Schedules 21 and 25) as well as customer groups which have a limited contribution to system peak usage (pumping and street lighting).

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 1

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	2.82%	0.55
General Service Schedule 11	10.55%	2.05
Large General Service Schedule 21	8.06%	1.57
Extra Large General Service Schedule 25	3.74%	0.73
Pumping Service Schedule 31	4.24%	0.83
Lighting Service Schedules 41 - 49	9.53%	1.86
Total Washington Electric System	5.14%	1.00

As can be observed from the above table, residential and extra large general service schedules (1 and 25) show significant under-recovery of the costs to serve them, the pumping service schedule (31) shows moderate under-recovery, 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.

Demand Study

Q. In the settlement agreement in Docket No. UE-070804[9], the Company agreed to conduct a new load and cost allocation study. Has Avista incorporated current load research into the cost-of-service study presented for this case?

A. Yes. The Company designed and implemented an ongoing 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 results based upon one full year of data. The goal was to have this study ready for regulatory proceedings no later than the Spring of 2010. The requirement of randomly selecting customers for participation in the study and the diverse and often low-density nature of much of our service territory demanded a high-quality and reliable metering and communication system to support a long-term study. The Company retained a load research consulting specialist to design the sample to deliver statistically valid results.

[9] In Order 10 ((UE-090134, UG-090135, & UG-060518) consolidated), at paragraph 31, the Commission noted "In accordance with the Settlement Agreement we approved in Dockets UE-070804 and UG-070805, Avista is expected to complete a new cost and load study in 2010."

Avista interviewed four consulting firms. Based on these interviews and other due diligence, the Company engaged the services of Mr. Curt Puckett of KEMA (formally known as RLW Analytics) to provide planning, sample design and selection, as well as analysis and reporting associated with Avista's Load Research Project. KEMA is a respected consulting firm specializing in electric utility load research.

Q. How many customers were selected for the project?

A. In total, 629 Avista customers were included in the overall sample. This included 404 customers within the Company's Washington service territory. The remaining 225 customers were in the Company's Idaho service territory.

Q. How were external stakeholders involved in this process?

A. The Company's load research team (consisting of Jon Powell, Jon Seubert, and myself) as well as Mr. Puckett of KEMA met with Commission staff and Tom Spinks of Public Counsel on May 22, 2008 in Olympia. The Company presented the initial plan for the study and requested input from the parties before finalizing the plan and commencing implementation of the project. Summaries of the presentation were subsequently distributed to the larger list of those invited but who were unable to attend in person. A project update was also sent to the parties on October 31, 2008 to mark the installation of the first of the sample meters. Finally, periodic updates were presented to the Company's External Energy Efficiency Board (Triple-E) as the parties on this board are largely the same as the parties interested in the Company's load study.

Since that time, Avista has been collecting the data from the meters and forwarding the resulting meter reads to KEMA for their analysis. On March 16, 2010, KEMA delivered to

Avista the final load research study[10]. The study report is attached as Exhibit No. __(TLK-5) and the supporting electronic files have been included in the accompanying workpapers.

Q. Were the stakeholders made aware of the key elements of the load research study?

A. Yes. Stakeholders were informed of the issues involved in choice of technology, sample selection and the timetable for the completion of the installation and evaluation.

Q. Did the results from the new load study cause major changes in the allocation of demand-related costs in the cost of service study in this case, as compared to prior cost of service studies?

A. No. Using the prior peak credit method cost of service model run (for an apples to apples comparison), the demand contribution of the different customer groups produced by the load study showed <u>very</u> similar over- and under-recovery relationships as studies from prior cases.

Q. Is the cost-of-service study the only anticipated use of the load research study?

A. No. We have found additional use for the load research in improving transformer design and potentially in the design and implementation of Smart Grid technologies. We are also contemplating the future use of this data to develop end-use load profiles.

Q. How will Avista maintain the study in the future?

A. It is Avista's intent to annually augment the existing customer sample with additional randomly selected participants beginning in 2011. These additional installations will

[10] Key result tables were provided in late February to facilitate incorporation of the load study results in the presented cost of service analysis, however the complete load study report was delivered in March.

ensure that the study sample continues to be representative of the population as a whole. The additional samples will be selected to maximize statistical precision of the rate classes and to serve the needs of evaluating future alternative rate designs and engineering topics that arise over time.

V. NATURAL GAS COST OF SERVICE

Q. Please identify the natural gas cost studies presented to this Commission in the last five years as required by WAC 480-07-510 (6).

A. Natural gas cost of service studies were filed with this Commission in Docket No. UG-090135, Docket No. UG-080417, Docket No. UG-070805 and Docket No. UG-050483.

Q. Please describe the natural gas cost of service study and its purpose.

A. A natural gas cost of service study is an engineering-economic study which separates the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. The groups are made up of customers with similar usage characteristics and facility requirements. Costs are assigned in relation to each group's test year 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-6) explains the basic concepts involved in performing a natural gas 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 natural gas cost of service study provided in this case?

A. The cost of service study provided by the Company as Exhibit No.__(TLK-7) is based on the twelve months ended December 2009 test year pro forma results of operations presented by Ms. Andrews in Exhibit No.__(EMA-3).

Q. Would you please explain the cost of service study presented in Exhibit No.__(TLK-7)?

A. Yes. Exhibit No. ___(TLK-7) is composed of a series of summaries of the cost of service study results. Page 1 shows the results of the study by FERC account category. The rate of return and the ratio of each schedule's return to the overall return are shown on lines 38 and 39. This summary is provided to Mr. Ehrbar for his work on rate spread and rate design. The results will be presented later in my testimony. Additional summaries show the costs organized by functional category (page 2) and classification (page 3), including margin and unit cost analysis at current and proposed rates. Finally, 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 Natural Gas Base Case cost of service study utilize the methodology from the Company's last natural gas 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. UG-090135.

Q. What are the key elements that define the cost of service methodology?

A. Allocations of gas costs and underground storage costs reflect the current purchased gas tracker methodology. Natural gas main investment has been segregated into large and small mains. Large usage customers that take service from large mains do not receive an allocation of small mains. Meter installation and services investment is allocated by number of customers weighted by the relative current cost of those items. System facilities that serve all customers are classified by the peak and average ratio that reflects the system load factor, then allocated by coincident peak demand and throughput, respectively. Demand side management costs are treated in the same way as system facilities. General plant is allocated by the sum of all other plant. Administrative & general expenses are segregated into labor-related, plant-related, revenue-related, and "other". The costs are then allocated by factors associated with labor, plant in service, or revenue, respectively. The "other" A&G amounts get a combined allocation that is one-half based on O&M expenses and one-half based on throughput. A detailed description of the methodology is included in Exhibit No.___(TLK-6).

Q. Does this methodology follow previously-approved methods?

A. Yes, with the exception of Company-specific purchased gas and related items that match the PGA assumptions, the methodology I have presented here, and in prior cases before this Commission, replicates the methodology established in Docket No. UG-940814 for Washington Natural (now Puget Sound Energy).

Q. What are the results of the Company's natural gas cost of service study?

A. I believe the Base Case cost of service study presented in this filing is a fair representation of the costs to serve each customer group. The study indicates that the Residential and Interruptible service schedules (101 and 131) are providing slightly less than the overall return (unity), and Small Firm general, Large Firm general, and Transportation service schedules (111, 121 and 146) are providing more than unity.

The following table shows the rate of return and the relative return ratio at present rates for each rate schedule:

Table 2

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 101	5.37%	0.94
Small Firm Service Schedule 111	6.80%	1.20
Large Firm Service Schedule 121	6.13%	1.08
Interruptible Service Schedule 131	5.56%	0.98
Transportation Service Schedule 146	6.54%	1.15
Total Washington Natural Gas System	5.68%	1.00

The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

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

A. Yes.