Exhibit No. ___(TLK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09______

DOCKET NO. UG-09______

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 Rate 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. I am a 1982 graduate of Washington State University with a Bachelor of Arts degree in General Humanities, and a Master of Accounting degree in 1990. As an employee in the Rate 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.

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II. REVENUE NORMALIZATION

Electric Revenue Normalization

Q. Would you please describe the electric revenue adjustment included in 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 September 2008 test period and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Washington net operating income by $23,394,000 as shown in column (W) on page 7 of Exhibit No.___(EMA-2). The revenue normalization adjustment consists of three primary components: 1) repricing customer usage (adjusted for any known and measurable changes) at present base tariff rates in effect, 2) adjusting customer loads and revenue to 12-month calendar basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue.

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, 2009 and the elimination of revenue and amortization expense from adder schedules, (Schedule 59 Residential Exchange, and Schedule 91 Public Purpose Tariff Rider[1]) is an increase of $42,272,000. The impact of the pro forma unbilled revenue compared to the amount included in results of operations is a reduction of $1,503,000 and the weather normalization adjustment reduces revenue by $3,517,000. The resulting net operating adjustment is $23,394.

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 September 2008 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[2]. The resulting seasonal weather sensitivity factors (use per customer per heating degree day and use per customer per cooling degree day)

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[1] City Business and Occupation Taxes and Energy Recovery Mechanism revenues are eliminated in separate adjustments.
[2] 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.

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. How are normal heating and cooling degree days defined?

A. Normal heating and cooling degree days are based on a rolling 30-year average of heating and cooling degree-days[3] 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. In Docket No. UE-080416 the Company used a twenty-five year rolling average to determine normal heating and cooling degree days for each month. As mentioned above, in this case an additional five years have been included in the rolling average calculation. Otherwise, the process is the same as the method presented in the last general rate case in Washington.

Q. Why are you proposing to change from a 25-year to a 30-year average for normal degree days?

A. In response to concerns from Commission staff that twenty-five years may be insufficient to determine "normal", I performed additional analysis comparing twenty-five year rolling averages to thirty year rolling averages for all available Spokane heating degree day data. This analysis revealed that while both thirty year averages and twenty-five year averages captured

[3] The National Climatic Data Center publication used to acquire the final quality controlled data for the Spokane Airport weather station did not include cooling degree day information prior to 1980. Consequently, the 30 year

the long term trend in regional temperatures, the thirty year averages produced more reliable statistical results.

The proposed averaging process maintains the advantage of reflecting current weather trends by updating the values annually, while providing a less volatile statistic through the use of additional years of data.

Q. What was the impact of electric weather normalization on the twelve months ended September 2008 test year?

A. Weather was colder than normal during the winter and spring, and warmer than normal during the summer of the test year. The adjustment to normal required the deduction of 294 heating degree-days and 45 cooling degree-days. The total adjustment to Washington sales volumes was a reduction of 45,996,924 kWhs which is approximately eight tenths of one percent of billed usage.

<u>Natural Gas Revenue Normalization</u>

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 September 2008 test period and retail revenues on a normalized (pro forma) basis. The adjustment includes the repricing of pro forma sales and transportation volumes at present rates using pro forma sales volumes that have been adjusted for unbilled sales,

average is actually a 29 year average including the years 1980 through 2008. As a rolling average, in all future years it would contain a full 30 years of data. Heating degree day information was available for all the desired years.

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.

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-082271, the Company's 2008 PGA filing[4], 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 an increase to net operating income of $3,648,000, as shown in column (I), page 5 of Exhibit No. ___(EMA-3).

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.

[4] The January 16, 2009 gas cost reduction to customer charges was accomplished through Schedule 155 which is excluded from base revenues.

Q. How are normal heating and cooling degree days defined?

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. Other than the change from a 25-year rolling average to a 30-year rolling average discussed with regards to electric weather normalization, 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-080417.

Q. What was the impact of natural gas weather normalization on the twelve months ended September 2008 test year?

A. Weather was colder than normal during the 2007/2008 heating season. The adjustment to normal required the deduction of 352 heating degree-days from October through June.[5] The adjustment to sales volumes was a reduction of 6,895,414 therms which is approximately 2.7 percent of billed usage. The margin impact (revenue less gas cost) of the weather adjustment was a reduction of $1,850,000.

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[5] 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.

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 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" 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 $0.05341 per kWh or $53.41 per mWh. The calculation of the retail revenue credit rate be revised based on the final production and transmission costs and rate of return that are approved by the Commission.

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. Are you sponsoring any exhibits related to the electric cost of service study?

A. Yes. I am sponsoring Exhibit No.__(TLK-3), electric cost of service study process description; and Exhibit No. ___(TLK-4), electric cost of service study summary results.

Q. Were these exhibits prepared by you?

A. Yes.

Q. Please identify the Company's electric cost studies presented to this Commission in the last five years.

A. An Electric cost of service study was presented to this Commission in Docket No. UE-050482, Docket No. UE-070804 and Docket No. UE-080416.

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 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 September 2008 test year pro forma results of operations presented by Company witness 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. Hirschkorn 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.

The Excel model used to calculate the cost of service and supporting schedules have been included in their 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 filed in the Company's last electric general rate 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-080416 with one enhancement.

Q. What is the nature of that enhancement?

A. In a cost of service study the direct assignment of costs is desirable whenever possible. The Company has included direct assignment of distribution substation costs to the Extra Large General Service customers on Schedule 25 for many years. In this study, that direct assignment has been extended to the primary voltage distribution facilities connected to the specific substations utilized by these twenty-two customers. This is discussed further in Exhibit No. ___(TLK-3), page 5.

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. In general the cost study follows the methodology established in Docket No. UE-920499 for Puget Sound Power and Light (now PSE). Production and transmission costs are classified to energy and demand by a peak credit analysis. The definition of peaks and peak credit are specific to Avista and 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, 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), see pages 5 and 9.

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

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

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	2.88%	0.66
General Service Schedule 11	9.35%	2.14
Large General Service Schedule 21	6.29%	1.44
Extra Large General Service Schedule 25	2.18%	0.50
Pumping Service Schedule 31	3.34%	0.76
Lighting Service Schedules 41 - 49	5.43%	1.24
Total Washington Electric System	4.37%	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. However, only general service schedule 11 currently provides a rate of return higher than the rate of return requested in this case (which is over twice the overall return). The summary results of this study were provided to Mr. Hirschkorn as an input into development of the proposed rates.

Q Is there something else that should be noted with regards to the cost study results?

A. Yes. As shown on page 1, lines 38 and 41 of Exhibit No.___(TLK-4) Schedules 1, 25, and 31 all do not provide enough net income to cover the interest expense (debt cost) associated with their rate base. Consequently, these Schedules have been allocated negative income tax which improves their net income and rate of return results. Simply comparing the relative return ratios in Table 1 fails to acknowledge that these schedules do not cover their debt cost at present rates.

V. DEMAND STUDY

Q. In the settlement agreement in Docket No. UE-070804, the Company agreed to conduct new load and cost allocation studies with input from Staff and other interested parties. What is the status of the electric demand study?

A. The Company has engaged the services of Mr. Curt Puckett of RLW Analytics (RLW) to provide planning, sample design and selection, as well as analysis and reporting associated with Avista's Load Research Project. RLW is a respected consulting firm specializing in electric utility load research. The Company's load research team (consisting of Jon Powell, Jon Seubert, and myself) as well as Mr. Puckett of RLW met with selected 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.

A project update was also sent to the parties on October 31, 2008 to mark the installation of the first of the sample meters. Since that time, nearly all sample meters have been installed and are collecting data (the last few are expected to be in place shortly).

Q. Has the Company provided any updated load data as part of the cost of service study in this case?

A. No. A <u>full year</u> of hourly load data is necessary to make use of the information in the cost of service demand allocations. The first full year of sample data will be collected over the calendar year 2009. Consequently, the earliest that a general rate filing could incorporate updated load study data would be sometime in 2010.

Q. Without updated load study information, is it reasonable for Mr. Hirschkorn to rely on the cost of service study results as a guide for the allocation of revenue to customer classes?

A. Yes, I believe it is for the following reasons. I elected to perform a sensitivity analysis on the demand allocations within the cost of service study. There are two types of demand allocations, namely **coincident** peak and **non-coincident** peak. The **coincident** peak allocations are applied to demand-related production and transmission costs. The **non-coincident** peak allocations are applied to demand-related distribution costs.

I ran two sensitivity cases to determine how changes in non-coincident demand for each customer class, i.e., from a new load study, would affect the allocation of demand costs. I also ran two sensitivity cases to determine how changes in coincident demand for each customer class would affect the allocation of demand costs.

Before I walk through the four sensitivity studies, it is important to have some context for what we are trying to test with the studies. Column (a) in the table below shows the relative rates of return for each customer class from our Base Case cost of service study under present retail rates. Column (b) shows the relative rates of return by schedule after application of the proposed rate increase in this case. As Mr. Hirschkorn explains in his testimony, the spread of the revenue increase to each customer class was designed to move each customer class closer to unity.

Table 2

Customer Class	Present Relative ROR (a)	Proposed Relative ROR (b)
Residential Service Schedule 1	0.66	0.79
General Service Schedule 11	2.14	1.67
Large General Service Schedule 21	1.44	1.28
Extra Large General Service Schedule 25	0.50	0.73
Pumping Service Schedule 31	0.76	0.82
Lighting Service Schedules 41 - 49	1.24	1.09
Total Washington Electric System	1.00	1.00

The table shows that the relative rate of return for some customer schedules is above unity (1.0) for both present rates and proposed rates, and others are below unity. The purpose of the sensitivity studies is to determine whether demand data from a new load study would likely cause us to spread the revenue increase to customer classes differently than that proposed by the Company in this case.

Q. What was your conclusion after running the four sensitivity studies?

A. The results of each of the studies, that I will explain below, show that while an updated load study may fine tune the cost relationships among the customer groups, we can expect relatively small changes in the overall cost of service results. Therefore, we believe the current cost of service study provides a sound foundation for rate spread purposes in this case.

Scenario 1

Q. What did you test in the first sensitivity run, and what did the results show?

A. The first sensitivity run, which I will refer to as Scenario 1, was designed to examine how a change in the **non-coincident** peak for each customer class would affect the allocation of demand-related **distribution** costs. For this scenario I simply took the non-coincident peak demand for each customer class embedded in the cost of service study, and doubled the demand for each class, with the exception of Schedule 25. By doubling the demand for each class, we will see what happens to demand allocations if a new load study were to show that the non-coincident peak demand for each class were to increase in the same proportion.

Q. Why did you not double the peak demand for Schedule 25?

A. We already have hourly metering, and hourly data, for Schedule 25, so we already know what their actual non-coincident peak demand is without a new load study. It is also important to note, as I mentioned earlier, that the non-coincident peak demand analysis is used entirely to allocate demand-related **distribution** costs. With the enhancement to the direct assignment included in this study, nearly all demand-related distribution costs for Schedule 25 are now directly assigned, and therefore, a change in the non-coincident demand would result in essentially no change in the allocation of distribution costs to these customers.

Q. What were the results of this first scenario?

A. The results from Scenario 1, compared with the Base Case cost of service study filed in this case, are summarized on Exhibit No.___(TLK-5), lines 1 through 8. Although the rate base and net income values change slightly, the relative rates of return for Scenario 1 are virtually the same as our Base Case study for all customer classes, as shown in the table below.

Table 3

Customer Class	Base Case Rate of Return		Scenario 1 Rate of Return	
Residential Service Schedule 1	2.88%	0.66	2.88%	0.66
General Service Schedule 11	9.35%	2.14	9.34%	2.14
Large General Service Schedule 21	6.29%	1.44	6.29%	1.44
Extra Large General Service Schedule 25	2.18%	0.50	2.18%	0.50
Pumping Service Schedule 31	3.34%	0.76	3.33%	0.76
Lighting Service Schedules 41 - 49	5.43%	1.24	5.43%	1.24
Total Washington Electric System	4.37%	1.00	4.37%	1.00

Therefore, if a new load study were to show a significant increase in non-coincident peak demand across all schedules, it would result in very little change in our cost of service results.

Scenario 2

Q. What did you test in Scenario 2, and what did the results show?

A. The first scenario explored what would happen if the non-coincident peak demand was higher for all schedules than our Base Case demand data. In Scenario 2, I wanted to test what would happen if a new load study were to indicate that some schedules have higher non-coincident peak demand than our Base Case, and other schedules have lower demand. For Scenario 2, I made the following adjustments to the Base Case non-coincident peak demand data:

1. For customer classes that have a relative rate of return above unity (1.0) in the Base Case study, I increased the non-coincident peak demand for the class by 15%.

2 For customer classes that have a relative rate of return below unity (1.0), I decreased the non-coincident peak demand for the class by 15%.

Q. What were you trying to measure by making these adjustments?

A. In this filing we are proposing a rate spread that is designed to move each customer class closer to unity. For example, for those customer classes that are above unity, we are proposing a lower percentage base rate increase in order to accomplish this movement. If a new load study were to show an increased non-coincident peak demand for these customer classes (above unity), and a lower non-coincident peak demand for the customer classes below unity, it would result in the following changes to the cost of service study:

1 The increase in non-coincident peak demand for customer classes above unity would result in an increased allocation of demand-related distribution costs to these customer classes, which would lower the relative rate of return for these classes (move them closer to unity).

2 The decrease in non-coincident peak demand for customer classes below unity would result in a decreased allocation of demand-related distribution costs to these customer classes, which would increase the relative rate of return for these classes (move them closer to unity).

The purpose of this scenario was to determine how much movement toward unity would occur for each customer class if the new load study were to show a significant increase in non-coincident peak demand for classes above unity, and a significant decrease for those below unity. As mentioned above, we increased the non-coincident peak demand for classes above unity by 15%, and reduced the demand for classes below unity by 15%.

Q. What were the results for Scenario 2?

A. The results of Scenario 2 are shown on Exhibit No. ___(TLK-5), lines 9 through 12. The table below highlights the rates of return produced by this scenario compared to the base case.

Table 4

Customer Class	Base Case Rate of Return		Scenario 2 Rate of Return	
Residential Service Schedule 1	2.88%	0.66	3.29%	0.75
General Service Schedule 11	9.35%	2.14	8.49%	1.94
Large General Service Schedule 21	6.29%	1.44	5.59%	1.28
Extra Large General Service Schedule 25	2.18%	0.50	2.18%	0.50
Pumping Service Schedule 31	3.34%	0.76	3.78%	0.86
Lighting Service Schedules 41 - 49	5.43%	1.24	5.18%	1.18
Total Washington Electric System	4.37%	1.00	4.37%	1.00

Costs did shift in this scenario, but not enough to change the rate spread implications. Schedules 11, 21 and Lighting service are still above unity, and Schedules 1 and 31 are improved but remain less than unity. Therefore, even if this Scenario were to occur, there would still be a need for a rate spread proposal to move relative rates of return for customer classes closer to unity, similar to what Mr. Hirschkorn has proposed in this case.

Q. Would you expect the new load study to show higher non-coincident peak demands for only the customer classes above unity, and lower non-coincident peak demands for only the customer classes below unity, as you tested in Scenario 2?

A. No. It is unlikely that such a scenario would actually occur. However, for my sensitivity analysis I wanted to test a scenario that is probably beyond what would likely occur.

Scenario 3

Q. Let's move on to the two sensitivity studies related to coincident peak. How are the class contributions to system peak demand determined in the Base Case?

A. The coincident peak allocation factor is based on the electric system hourly peak for each month of the twelve-month test period (12 hourly coincident peaks). The total Washington peak load is known for the twelve peak hours.

With regard to each customer class, the peak demand for each class, for each of the 12 monthly peak hours (contribution to the system peak) is based on an analysis of monthly billing data, weather sensitivity statistics, and hourly load shapes from prior load studies.

Q. Are the twelve hourly coincident peaks for Schedule 25 estimated in the same manner?

A. No. As I mentioned earlier, we have actual hourly load data for Schedule 25 and therefore, we know what their usage is at the time of the twelve monthly system peaks. Thus, with regard to the use of peak demand data in cost of service studies to allocate demand-related production and transmission costs, the current cost of service study already includes the actual metered contribution to the system peak for these schedules.

Q. What change did you make to the coincident peak demand data in Scenario 3, and what were you trying to measure?

A. In Scenario 3, I made one change from the Base Case in the determination of the hourly coincident peak contribution for each schedule. Rather than use hourly load shapes from prior load studies to determine the hourly peak for each customer class on the peak day, I used one-sixteenth, or 6.25%, of the <u>daily energy use</u> on the peak day for each class to represent the <u>hourly peak demand</u> at the time of the system coincident peak.

The use of 6.25% of daily energy to represent a peak hour demand for the peak day has been used historically in the natural gas industry to determine the appropriate size of natural gas delivery service equipment. Although the 6.25% may not be perfectly transferrable to the electric industry, it provided a reasonable basis to achieve my objective in this scenario.

My objective in Scenario 3 was to adjust the peak demand data such that the peak hour for each customer class occurred at the time of the system peak, i.e., all customer classes peak at the time of the system peak in each of the twelve months.

Q. What were the results of this Scenario 3?

A. Scenario 3 results are shown on Exhibit No.___(TLK-5), lines 13 through 16. The table below highlights the rates of return produced by this scenario compared to the Base Case.

Table 5

Customer Class	Base Case Rate of Return		Scenario 3 Rate of Return	
Residential Service Schedule 1	2.88%	0.66	2.91%	0.67
General Service Schedule 11	9.35%	2.14	9.45%	2.16
Large General Service Schedule 21	6.29%	1.44	6.23%	1.42
Extra Large General Service Schedule 25	2.18%	0.50	2.18%	0.50
Pumping Service Schedule 31	3.34%	0.76	3.00%	0.69
Lighting Service Schedules 41 - 49	5.43%	1.24	5.43%	1.24
Total Washington Electric System	4.37%	1.00	4.37%	1.00

The rate of return and return ratios for Schedules 1 and 11 rise slightly, while they fall somewhat for 21 and 31, but the rate spread implications remain unchanged.

Scenario 4

Q. What did you test in the fourth scenario?

A. In Scenario 4, I wanted to test what would happen if a new load study were to indicate that some schedules have higher contribution to the system coincident peak than the Base Case, and other schedules have a lower contribution.

For Scenario 4, I made the following adjustments to the Base Case coincident peak demand data:

1 For customers classes that have a relative rate of return above unity (1.0) in the Base Case study, I increased the demand for the class at the time of the system coincident peak by approximately 10%.[7]

2 For customer classes that have a relative rate of return below unity (1.0) in the Base Case study, I decreased the demand for the class at the time of the system coincident peak by approximately 10%.

Q. What were you trying to measure by making these adjustments?

A. As I explained earlier related to Scenario 2, in this filing we are proposing a rate spread that is designed to move each customer class closer to unity. If a new load study were to show an increased contribution to the system coincident peak for the customer classes above unity, and a lower contribution to the system coincident peak for the customer classes below unity, it would result in the following changes to the cost of service study:

1 The increased contribution to the system coincident peak for customer classes above unity would result in an increased allocation of demand-related production and transmission costs to these customer classes, which would lower the relative rate of return for these classes (move them closer to unity).

2 The decreased contribution to the system coincident peak for customer classes below unity would result in a decreased allocation of demand-related production and

[7] In order to preserve the same level of Washington peak demand as the Base Case, it was necessary to adjust the percentage increase to Schedules 11, 21 and Street and Area Lights by 12%, and reduce the percentage decrease for Schedules 1, and 31 to 8.5%.

transmission costs to these customer classes, which would increase the relative rate of return for these classes (move them closer to unity).

The purpose of this scenario was to determine how much movement toward unity would occur for each customer class if the new load study were to show a significant increase in contribution to the system coincident peak for classes above unity, and a significant decrease for those below unity.

Q. What were the results for Scenario 4?

A. Scenario 4 results are shown on Exhibit No. ___(TLK-5), lines 17 through 20. The table below highlights the rates of return produced by this scenario compared to the base case.

Table 6

Customer Class	Base Case Rate of Return		Scenario 4 Rate of Return	
Residential Service Schedule 1	2.88%	0.66	3.11%	0.71
General Service Schedule 11	9.35%	2.14	8.88%	2.03
Large General Service Schedule 21	6.29%	1.44	5.89%	1.35
Extra Large General Service Schedule 25	2.18%	0.50	2.18%	0.50
Pumping Service Schedule 31	3.34%	0.76	3.56%	0.81
Lighting Service Schedules 41 - 49	5.43%	1.24	5.37%	1.23
Total Washington Electric System	4.37%	1.00	4.37%	1.00

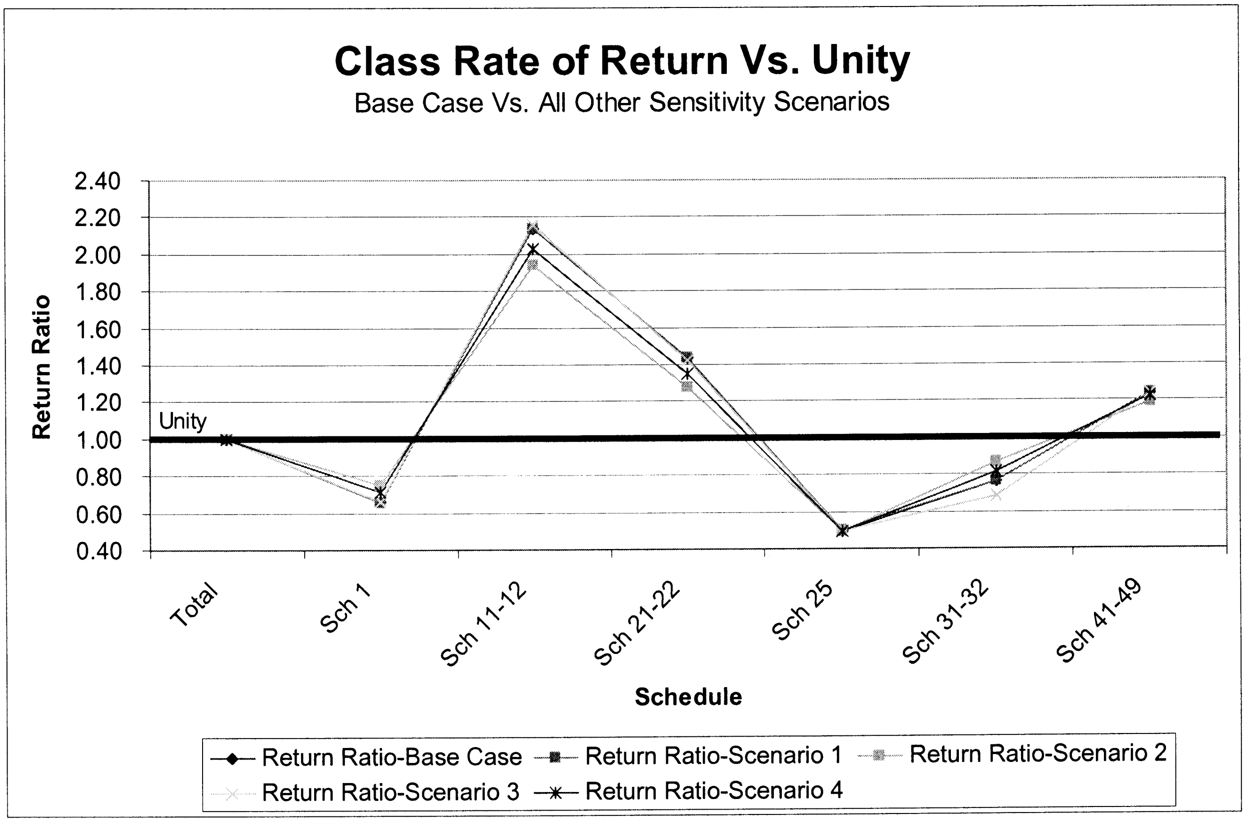
The rate of return and return ratios for Schedules 1 and 31 improve, but are still well below unity. The return ratios for Schedule 11, and 21 each drop by about one-tenth but are still well above unity. The rate spread implications remain essentially unchanged.

Q. Would you expect the new load study to show a <u>higher</u> contribution to the system coincident peak for only the customer classes <u>above unity</u>, and a lower contribution to the system coincident peak for only the customer classes <u>below unity</u>, as you tested in Scenario 4?

A. No. As with Scenario 2, it is unlikely that such a scenario would occur. However, again, for my sensitivity analysis I wanted to test a scenario that is probably beyond what would likely occur.

Q. What conclusions do you draw from these demand allocation sensitivity studies?

A. The following chart illustrates the return ratios for the Base Case and all four sensitivity scenarios:



As can be seen in the chart above, the sensitivity analyses demonstrate that, while an updated load study may fine tune the cost relationships among the customer groups, we can expect only relatively small changes in the results. The schedules that are well above unity will continue to be above unity, and the schedules that are well below unity will continue to be below unity. (There will be little or no change to Schedule 25 which already has actual hourly demand data and receives direct assignment of most distribution plant.) Therefore, the Company believes that the existing cost of service study, <u>even absent</u> new load study information, provides a sound foundation for rate spread purposes.

V. NATURAL GAS COST OF SERVICE

Q. Are you sponsoring any exhibits related to the natural gas cost of service study?

A. Yes. 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.

Q. Please identify the natural gas cost studies presented to this Commission in the last five years.

A. Natural gas cost of service studies were filed with this Commission in Docket No. UG-080417, Docket No. UG-070805, Docket No. UG-050483 and Docket No. UG-041515.

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 September 2008 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. Hirschkorn for his work on rate spread and rate design. The results will be discussed in more detail later in my testimony. The 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.

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-080417.

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 PSE).

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 Small Firm and Large Firm general service schedules (111 and 121) are providing slightly less than the overall return (unity), and Interruptible and Transportation service schedules (131 and 146) are providing slightly more than unity. Residential service on Schedule 101 has a return ratio of 1.00 indicating that schedule is essentially at unity. The return for all of the rate groups are relatively close to the overall return indicating that the current rate spread is fair.

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

Table 7

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 101	6.98%	1.00
Small Firm Service Schedule 111	6.83%	0.98
Large Firm Service Schedule 121	6.48%	0.93
Interruptible Service Schedule 131	7.20%	1.03
Transportation Service Schedule 146	7.97%	1.15
Total Washington Natural Gas System	6.96%	1.00

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

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

A. Yes.