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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-09-01 CASE NO. AVU-G-09-01 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 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. Yes. 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 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.

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

A. Yes. I am sponsoring Exhibit No. 11 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, Demand

Sensitivity Results summary; 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.

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 September 2008 test period and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $14,065,000 as shown in column (u) on page 6 of Ms. Andrews Exhibit No.10, 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.

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 October 1, 2008 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 $23,880,000. The impact of the pro forma unbilled revenue compared to the amount included in results of operations is a reduction of $31,000, and the weather normalization adjustment reduces revenue by $1,837,000. The resulting net operating income adjustment is $14,065,000.

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

[1] City Franchise Fee and Power Cost Adjustment revenues are eliminated in separate adjustments.

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. 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 reported for each month by the National Weather Service for the Spokane Airport weather station. For heating, the 30 years are included on a heating season basis, July through June, so, for example, the October average reflects all the Octobers beginning in 1978 and through 2007, whereas the May average reflects all of the Mays beginning in 1979 and through 2008. For cooling, the 30 years reflect the cooling season calendar years beginning in 1979 and through 2008[2]. Each year the normal

[2] 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 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.

values will be adjusted to capture the next heating and cooling season with the oldest data dropping off, thereby encapsulating the most recent information available at the end of each calendar year.

Q. Are there any changes in the weather adjustment methodology since the company's last general rate case in Idaho?

A. Yes. In Case No. AVU-E-08-01 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[3] as the method introduced in Case No. AVU-E-08-01.

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 in another jurisdiction that twenty-five years may be insufficient to determine "normal," I performed additional analysis on how the rolling averages change over time. Specifically, I compared twenty-five year rolling averages to thirty year rolling averages for all data available from the NOAA published Annual Climatological Summary for the Spokane

[3] The regression analysis presented in Case No. AVU-E-08-01 used ten years of data for Schedule 1 and five years for all other schedules. In the updated analysis Schedule 1 no longer met all the statistical tests with ten years of data. The five year analysis passed all the tests and was used in this analysis.

Airport weather station. This analysis revealed that while both a thirty-year average and a twenty-five year average captures the long term trend in regional temperatures, the thirty-year averages showed less variability.

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 Idaho sales volumes was a reduction of 24,948,329 kWhs which is approximately 0.7 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 re-pricing of pro forma sales and transportation volumes at present rates (effective October 1, 2008) 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.

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 Case No. AVU-G-08-03, 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

[4] The January 6, 2009 gas cost reduction to customer charges was accomplished through Schedule 155 which is excluded from base revenues.

$2,359,000, as shown in column (i), page 5 of Ms. Andrews Exhibit No.10, 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. How are normal heating 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. The 30 years are included on a heating season basis, July through June, so, for example, the October average reflects all the Octobers beginning in 1978 and through 2007 whereas the May average reflects all of the Mays beginning in 1979 and through 2008. Each year the normal values will be adjusted to capture the next heating season with the oldest data dropping off, thereby encapsulating 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, were any changes made to the gas weather normalization methodology?

A. No, the process for determining the weather sensitivity factors and the monthly adjustment calculation are the same as the method introduced in Case No. AVU-G-08-01.

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. Warmer than normal weather that occurred during the summer months did not impact gas usage as customers are at baseload during that time. The adjustment to sales volumes was a reduction of 2,827,731 therms which is approximately 2.3 percent of billed usage. The margin impact (revenue less gas cost) of the weather adjustment was a reduction of $834,000.

III. PROPOSED RETAIL REVENUE CREDIT RATE

Q. Company witness Mr. Johnson discusses using the average cost of production and transmission for the retail revenue credit rate in the Power Cost Adjustment (PCA). How is that rate determined?

A. The retail revenue credit rate is determined by computing the proposed revenue requirement on the production and transmission subset of 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.

Q. Is this process illustated in an Exhibit?

A. Yes. Exhibit No. 11, 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 subset of these 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.

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

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. 11, 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.11, Schedule 3 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.10, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 11, Schedule 3?

A. Yes. Exhibit No. 11, 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. 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 accepted in the Company's last electric general rate case in Idaho?

A. Yes. The Base Case cost of service study was prepared using the methodology accepted by the Idaho commission in Case No. AVU-E-04-01 and used in Case No. AVU-E-08-01.

Q. Given that the specific details of this methodology are described in Exhibit No. 11, Schedule 2, would you please give a brief overview of the key elements and the history associated with those elements?

A. Yes. Production and transmission costs are classified to energy and demand by a peak credit analysis. Avista has been using the peak credit classification process for cost of service studies in both Washington and Idaho jurisdictions since the 1980's. Distribution costs are classified and allocated by the basic customer theory[5] 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.

[5] 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.

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	4.56%	0.85
General Service Schedule 11	7.89%	1.48
Large General Service Schedule 21	6.74%	1.26
Extra Large General Service Schedule 25	3.15%	0.59
Ex. Lg. Gen. Service Potlatch Schedule 25P	3.93%	0.73
Pumping Service Schedule 31	7.64%	1.43
Lighting Service Schedules 41 - 49	4.89%	0.92
Total Idaho Electric System	5.34%	1.00

As can be observed from the above table, residential, extra large general service, and lighting service schedules (1, 25, 25P, and 41-49) show under-recovery of the costs to serve them, while the general, large general, and pumping service schedules (11, 21, and 31) show over-recovery of the costs to serve them. However, all customer groups are currently providing a rate of return lower than the rate of return requested in this case. The summary results of this study were provided to Mr. Hirschkorn as an input into development of the proposed rates.

V. 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 last 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 <u>or, in the alternative, show how the lack of such an update affects COS-based revenue allocations to customer classes</u>. (emphasis added)

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

A. No. While an electric demand study is currently underway, with nearly all sample meters in place collecting data (and the last few expected to be in place shortly), <u>a 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. Have you performed a sensitivity analysis to determine the potential impact of updated load information on cost of service based revenue allocations to customer classes?

A. Yes. 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 (with the exception of Street and Area Lights).

	Present Relative ROR (a)	Proposed Relative ROR (b)
Residential Sch. 1	0.85	0.86
General Srvc. Sch. 11	1.48	1.27
Lg. Gen. Srvc. Sch. 21	1.26	1.17
Ex. Lg. Gen. Srvc. Sch. 25	0.59	0.84
Potlatch-Lewiston Sch. 25P	0.73	0.99
Pumping Srvc. Sch. 31	1.43	1.28
Street & Area Lgt. Schs.	0.92	0.73
Overall	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.

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 Schedules 25 and 25P. 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 Schedules 25 and 25P?

A. We already have hourly metering, and hourly data, for Schedules 25 and 25P, 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. Nearly all demand-related distribution costs for Schedules 25 and 25P are directly assigned, and therefore, a change in the non-coincident peak demand for these Schedules would result in essentially no change in the allocation of distribution costs to these Schedules.

Q. What were the results from 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 11, Schedule 4, 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 Illustration 2 below.

Illustration 2:

Customer Class	Base Case Rate of Return		Scenario 1 Rate of Return	
Residential Service Schedule 1	4.56%	0.85	4.56%	0.85
General Service Schedule 11	7.89%	1.48	7.89%	1.48
Large General Service Schedule 21	6.74%	1.26	6.74%	1.26
Extra Large General Service Schedule 25	3.15%	0.59	3.16%	0.59
Ex. Lg. Gen. Service Potlatch Schedule 25P	3.93%	0.73	3.94%	0.74
Pumping Service Schedule 31	7.64%	1.43	7.64%	1.43
Lighting Service Schedules 41 - 49	4.89%	0.92	4.89%	0.92
Total Idaho Electric System	5.34%	1.00	5.34%	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 a 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. 11, Schedule 4, lines 9 through 12. Illustration 3 below highlights the rates of return produced by this scenario compared to the base case.

Illustration 3:

Customer Class	Base Case Rate of Return		Scenario 2 Rate of Return	
Residential Service Schedule 1	4.56%	0.85	5.19%	0.97
General Service Schedule 11	7.89%	1.48	7.09%	1.33
Large General Service Schedule 21	6.74%	1.26	5.89%	1.10
Extra Large General Service Schedule 25	3.15%	0.59	3.15%	0.59
Ex. Lg. Gen. Service Potlatch Schedule 25P	3.93%	0.73	3.93%	0.73
Pumping Service Schedule 31	7.64%	1.43	6.85%	1.28
Lighting Service Schedules 41 - 49	4.89%	0.92	5.02%	0.94
Total Idaho Electric System	5.34%	1.00	5.34%	1.00

Costs did shift in this scenario, but not enough to change the rate spread implications. Schedules 11, 21 and 31 are still above unity, and Schedules 1 and Lighting service 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 <u>higher</u> non-coincident peak demands for only the customer classes <u>above unity</u>, and <u>lower</u> non-coincident peak demands for only the customer classes <u>below unity</u>, 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. Lets 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 Idaho 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 Schedules 25 and 25P estimated in the same manner?

A. No. As I mentioned earlier, we have actual, hourly load data for Schedules 25 and 25P, 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 Scenario 3?

A. Scenario 3 results are shown on Exhibit 11, Schedule 4, lines 13 through 16. Illustration 4 below highlights the rates of return produced by this Scenario compared to the Base Case.

Illustration 4:

Customer Class	Base Case Rate of Return		Scenario 3 Rate of Return	
Residential Service Schedule 1	4.56%	0.85	4.66%	0.87
General Service Schedule 11	7.89%	1.48	7.96%	1.49
Large General Service Schedule 21	6.74%	1.26	6.55%	1.23
Extra Large General Service Schedule 25	3.15%	0.59	3.15%	0.59
Ex. Lg. Gen. Service Potlatch Schedule 25P	3.93%	0.73	3.93%	0.73
Pumping Service Schedule 31	7.64%	1.43	6.77%	1.27
Lighting Service Schedules 41 - 49	4.89%	0.92	4.89%	0.92
Total Idaho Electric System	5.34%	1.00	5.34%	1.00

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

<u>Scenario 4</u>

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 a 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 demand data:

1. For customer classes that have a relative rate of return above unity (1.0), I increased the demand for the class at the time of the system coincident peak by approximately 10%.[6]

2. For customer classes that a have a relative rate of return below unity (1.0), 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,

[6] In order to preserve the same level of Idaho peak demand as the Base Case, it was necessary to adjust the percentage increase to Schedules 11, 21 and 31 to 11.6%, and reduce the percentage decrease for Schedules 1 and Lighting service to 9.4%.

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 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 of Scenario 4?

A. Scenario 4 results are shown on Exhibit 11, Schedule 4, lines 17 through 20. Illustration 5 below highlights the rates of return produced by this scenario compared to the Base Case.

Illustration 5:

Customer Class	Base Case Rate of Return		Scenario 4 Rate of Return	
Residential Service Schedule 1	4.56%	0.85	5.06%	0.95
General Service Schedule 11	7.89%	1.48	7.26%	1.36
Large General Service Schedule 21	6.74%	1.26	6.09%	1.14
Extra Large General Service Schedule 25	3.15%	0.59	3.15%	0.59
Ex. Lg. Gen. Service Potlatch Schedule 25P	3.93%	0.73	3.93%	0.73
Pumping Service Schedule 31	7.64%	1.43	7.08%	1.32
Lighting Service Schedules 41 - 49	4.89%	0.92	4.95%	0.93
Total Idaho Electric System	5.34%	1.00	5.34%	1.00

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

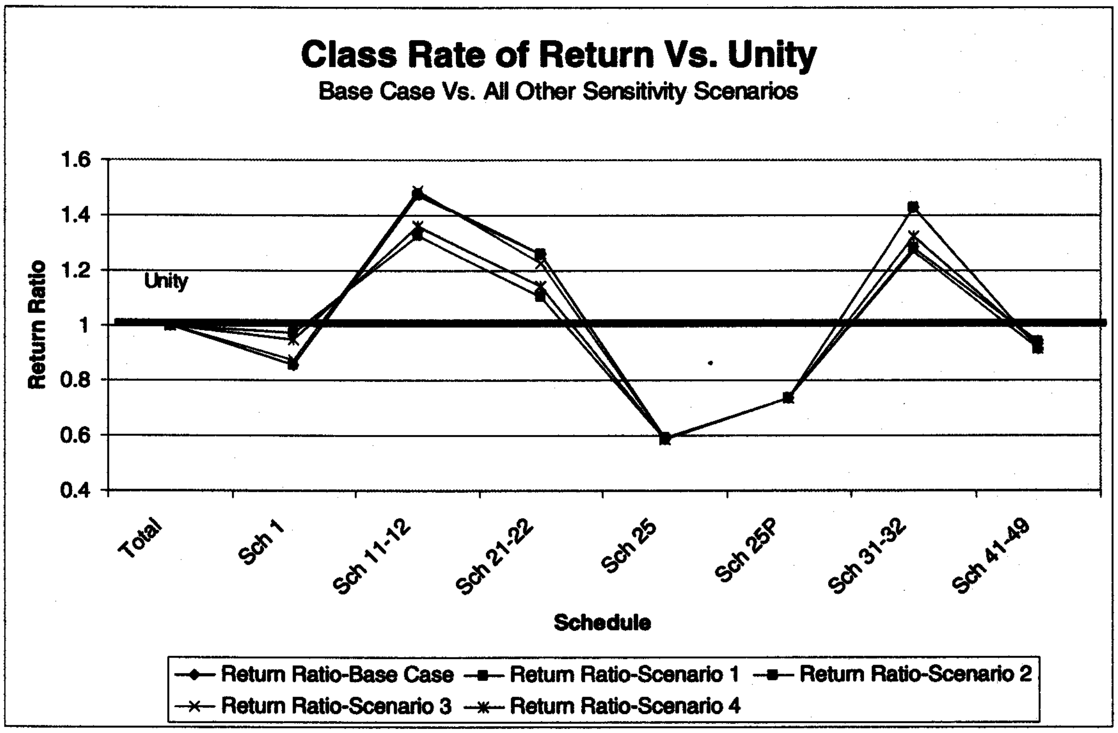
Q. Would you expect the new load study to show a <u>higher</u> contribution to the system coincident peak for only the customer classes <u>above unity</u>, and a <u>lower</u> contribution to the system coincident peak for only the customer classes <u>below unity</u>, as you tested in Scenario 4?

A. No. As with Scenario 2, it is unlikely that such a scenario would actually 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:

Illustration 6:



As can be seen in Illustration 6 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 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 Schedules 25 and 25P, which already have actual, hourly demand data and receive 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.

VI. NATURAL GAS COST OF SERVICE

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 groups' 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.11, Schedule 5 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.11, Schedule 6 is based on the twelve months ended September 2008 test year pro forma results of operations presented by Ms. Andrews in Exhibit No.10, Schedule 2.

Q. Would you please explain the cost of service study presented in Exhibit No. 11, Schedule 6?

A. Yes. Exhibit No. 11, Schedule 6 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 have been included in their 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 Idaho?

A. Yes. The Base Case cost of service study was prepared using the methodology accepted by the Idaho Commission in Case No. AVU-G-04-01 and AVU-G-08-01.

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

A. Purchased gas costs are derived from the current purchased gas tracker methodology. Underground storage costs are allocated by normalized winter throughput. 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.11, Schedule 5.

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 Large Firm general service Schedule 111 is providing slightly less than the overall return (unity), while all other schedules are providing slightly more than unity to varying degrees. The return for all of the Schedules are relatively close to the overall return indicating 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:

Illustration 7:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 101	6.97%	1.02
Small Firm Service Schedule 111	6.24%	0.91
Interruptible Service Schedule 131	7.44%	1.08
Transportation Service Schedule 146	8.78%	1.28
Total Idaho Natural Gas System	6.87%	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.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-09-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-09-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 11
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND GAS)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED SEPTEMBER 30, 2008

Column	Description of Adjustment	(000's)	Production/Transmission Revenue	Production/Transmission Expense	Rate Base
b	Per Results Report		87,662	196,202	337,543
c	Deferred FIT Rate Base			-	(47,411)
d	Deferred Gain on Office Building			-	
e	Colstrip 3 AFUDC Elimination		-	202	1,956
f	Colstrip Common AFUDC		-	-	925
g	Kettle Falls & Boulder Park Disallow.		-	-	(2,233)
h	Customer Advances			-	
i	Weatherizn and DSM Investment		-	-	1,669
	Actual		87,662	196,404	292,449
j	Depreciation True-up		-	(377)	-
k	Eliminate B & O Taxes			-	
l	Property Tax			1,143	
m	Uncollect. Expense			-	
n	Regulatory Expense			-	
o	Injuries and Damages			-	
p	FIT			-	
q	Idaho PCA			5,603	
r	Nez Perce Settlement Adjustment			(12)	
s	Eliminate A/R Expenses			-	
t	Misc Restating Adjs			-	
u	Revenue Normalization Adjustment		59	1,358	
v	Clark Fork PM&E			1,010	
w	Restate Debt Interest			-	
	Restated Total		87,721	205,129	292,449
PF1	Pro Forma Power Supply		(55,375)	(45,585)	-
PF2	Pro Forma Production Property Adj		(1,332)	(6,528)	(10,202)
PF3	Pro Forma Labor Non-Exec			399	
PF4	Pro Forma Labor Exec			5	
PF5	Pro Forma Transmission Rev/Exp		13	5	-
PF6	Pro Forma Capital Add 2008			(39)	3,427
PF7	Pro Forma Capital Add 2009			661	2,929
PF8	Pro Forma Information Services			-	-
PF9	Pro Forma Asset Management			240	-
PF10	Pro Forma Spokane Rvr Relicensing			2,100	12,184
PF11	Pro Forma CDA Tribe Settlement			401	7,861
PF12	Pro Forma Montana Lease			1,917	1,583
PF13	Pro Forma Colstrip Mercury Emiss. O&M			596	-
PF14	Pro Forma Incentives			-	
PF16	Pro Forma ID AMR			-	
PF15	Pro Forma CS2 Levelized Adj			199	
PF16	Pro Forma ID AMR			-	
PF17	Pro Forma O&M Plant Expense			1,400	
PF18	Pro Forma Employee Benefits			368	
PF19	Pro Forma Insurance			-	
PF20	Pro Forma Chicago Climate (CCX)		425	-	
PF21	Pro Forma Wartsila Amortization			185	
PF22	Pro Forma Colstrip Lawsuit Stlmnt			369	
	Pro Forma Total		31,452	161,822	310,231

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED SEPTEMBER 30, 2008

Proposed Production and Transmission Revenue Requirement
Calculation of Retail Revenue Credit Rate at Proposed Return

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	$310,231	
2		Proposed Rate of Return	8.800%	3.300%
3	Rate Base	Net Operating Income Requirement	$27,300	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,583)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	130,370	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($45,629)	
7	Total Prod/Trans	Net Operating Income Requirement	$108,457	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$166,857	
10	12ME Sept 2008 ID Normalized Retail Load MWh		3,487,446	
11	Prod/Trans Rev Requirement per kWh (Retail Revenue Credit Rate)		$ 0.04785	

1. ELECTRIC COST OF SERVICE

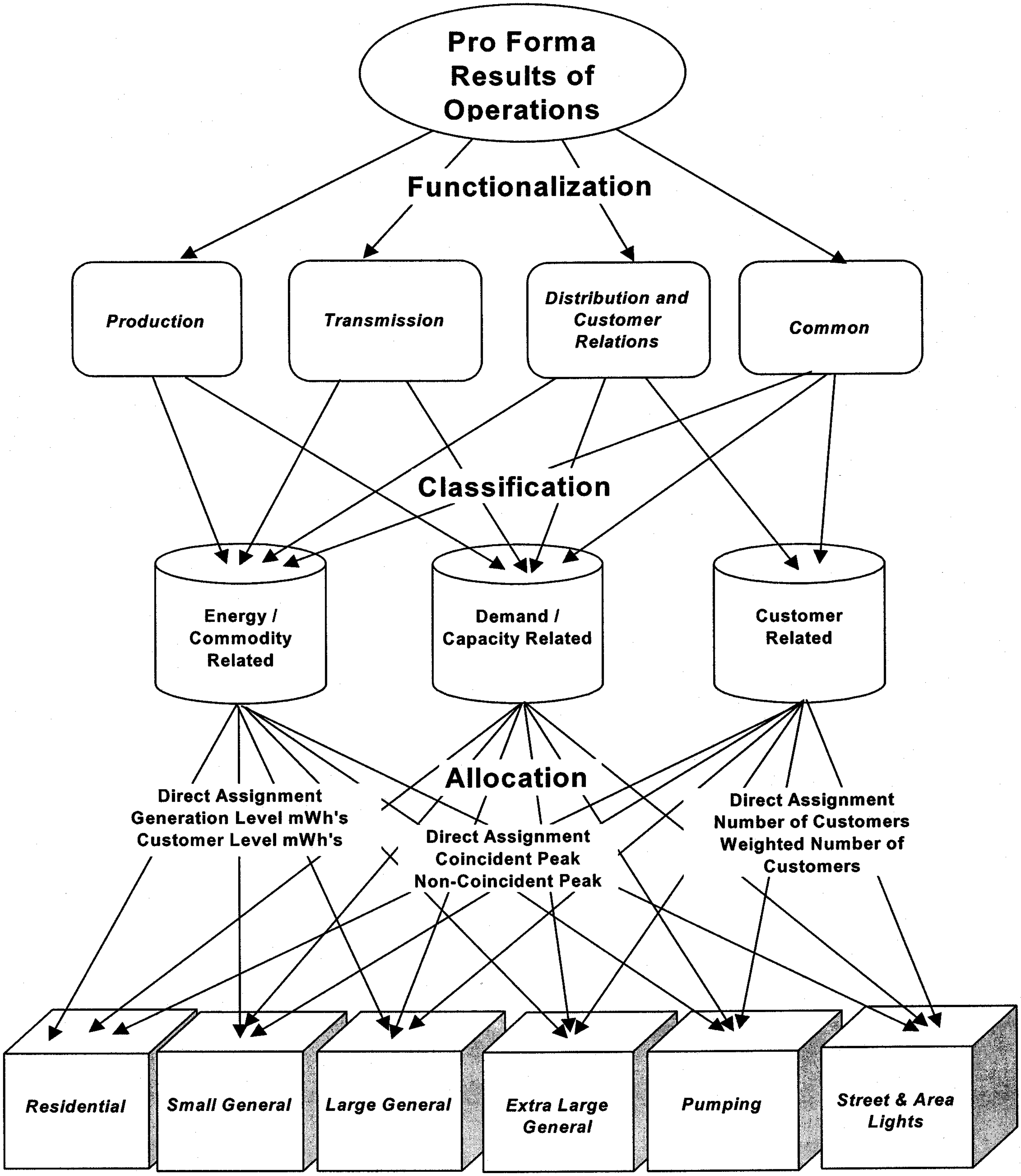
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, transmission, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items that cannot be directly assigned to customer groups are classified into three primary cost components: energy, demand or customer related. Energy related costs are allocated based on each rate schedule's share of commodity consumption. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to peak demand. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

Exhibit No. 11
Case No. AVU-E-09-01
T. Knox, Avista
Schedule 2, p. 2 of 9

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production and Transmission Classification (Peak Credit)

This study utilizes a Peak Credit methodology to classify production and transmission costs into demand and energy classifications. The Peak Credit method acknowledges that baseload production facilities provide energy throughout the year as well as capacity during system peaks and likewise the transmission system is built not only for peak use, but also for everyday delivery of energy. The demand/energy ratio is determined by the relationship of the current replacement cost per kW generating capacity of the Company's peaking units to the current replacement cost per kW generating capacity of the Company's thermal or hydro plant. The peak credit ratio for thermal plant is 37.16% to demand and 62.84% to energy. The peak credit ratio for hydro plant is 36.49% to demand and 63.51% to energy. As an intermediate resource (between peaking and baseload), Coyote Springs II has been included with the thermal plant costs, whereas all other plants in the 340 to 349 FERC plant accounts are considered peaking units.

Transmission costs are classified by fifty-fifty weighting of the thermal and hydro peak credit ratios resulting in the transmission peak credit ratio of 36.49% to demand and 63.51% to energy. Fuel and load dispatching expenses are classified entirely to energy. Peaking plant related costs are classified entirely to demand. Purchased Power and Other Power Supply expenses are classified to demand and energy by the relative amounts of assigned and allocated Production Plant in Service.

Production and Transmission Allocation

Production and transmission demand related costs are allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads. Although the Company is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

Energy related costs are allocated to class by pro forma annual kilowatthour sales adjusted for losses to reflect generation level consumption.

Distribution Facilities Classification (Basic Customer)

The Basic Customer method considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution plant. All other distribution plant is then considered demand related. This division delineates plant which benefits an individual customer from plant which is part of the system. The basic customer method provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part they are classified as customer related. Exceptions are sales expenses which are classified as energy related and uncollectible accounts expense which is considered separately as a revenue conversion item. Demand Side Management expenses recorded in Account 908 are also considered separately from the other customer information costs.

The demand side management investment and amortization are classified implicitly to demand and energy by the sum of production plant in service, then allocated to rate schedules by coincident peak demand and energy consumption respectively.

Distribution Cost Allocation

Distribution demand related costs which cannot be directly assigned are allocated to customer class by the average of the twelve monthly non-coincident peaks for each class. Distribution facilities that serve only secondary voltage customers are allocated by the non-coincident peak excluding primary voltage customers or number of customers excluding primary voltage customers. This includes line transformers, services, and secondary voltage overhead or underground conductors and devices. The costs of specific substations and related primary voltage distribution facilities are directly assigned to Extra Large General Service customers based on their load ratio share of the substation capacity from which they receive service.

Most customer costs are allocated by average number of customers. Weighted customer allocators have been developed using typical current cost of meters, estimated meter reading time, and direct assignment of billing costs for hand-billed customers. Street and area light customers are excluded from metering and meter reading expenses as their service is not metered.

Administrative and General Costs

Administrative and general costs which are directly associated with production, transmission, distribution, or customer relations functions are directly assigned to those functions and allocated to customer class by the relevant plant or number of customers. The remainder of administrative and general costs are considered common costs, and have been left in their own functional category. These common costs are classified by the implicit relationship of energy, demand and customer within the four-factor allocator applied to them. The four-factor allocator consists of a 25% weighting of each of the following: 1) operating & maintenance expenses excluding resource costs, labor expenses, and administrative and general expenses; 2) operating and maintenance labor expenses excluding administrative and general labor expenses; 3) net production, transmission, and distribution plant; and 4) number of customers.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax adjusted by interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category by that ratio. Similarly, income tax items have been reduced to a percent of net income before tax then assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case cost of service study.

IPUC Case No. AVU-E-09-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Production Plant			
1	Thermal Production	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Hydro Production	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Production (Coyote Springs)	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other Production	P = Production	Demand	D01 Coincident Peak Demand
	Transmission Plant			
5	All Transmission	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Distribution Plant			
6	360 Land	D = Distribution	Demand	D02 Non-coincident Peak Demand (NCP)
7	361 Structures	D = Distribution	Demand	D03/D04/D05 Direct Assign Large / Non-coincident Peak Demand Excl DA
8	362 Station Equipment	D = Distribution	Demand	D03/D04/D05 Direct Assign Large / Non-coincident Peak Demand Excl DA
9	364 Poles Towers & Fixtures	D = Distribution	Demand	D03/C04/D06/D07 Direct Assign Large & Lights / NCP Excl DA / NCP Secondary
10	365 Overhead Conductors & Devices	D = Distribution	Demand	D03/C04/D06 Direct Assign Large / NCP Excl DA / NCP Secondary
11	366 Underground Conduit	D = Distribution	Demand	D03/C04/D06 Direct Assign Large / NCP Excl DA / NCP Secondary
12	367 Underground Conductors & Devices	D = Distribution	Demand	D03/C04/D06 Direct Assign Large / NCP Excl DA / NCP Secondary
13	368 Line Transformers	D = Distribution	Demand	D06 Non-coincident Peak Demand Secondary
14	369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
15	370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
16	373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
	General Plant			
17	All General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Intangible Plant			
18	301 Organization	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
19	302 Franchises & Consents - Hydro Relicensing	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
20	303 Misc Intangible Plant - Transmission Agreements	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
21	303 Misc Intangible Plant - Software	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Reserve for Depreciation/Amortization			
22	Intangible	P/T/O	Follows Related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
23	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
24	Transmission	T = Transmission	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
25	Distribution	D = Distribution	Follows Related Plant	D02/D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
26	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Other Rate Base			
27	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
28	282/190 Accumulated Deferred Income Tax	P/T/D/O by Plant Balances	Follows Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
29	Gain on Sale of General Office Building	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
30	Hydro Related Deferred Balances	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
31	Demand Side Management Investment	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
	Production O&M			
32	Thermal	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
33	Thermal Fuel (501)	P = Production	Energy	E02 Annual Generation Level Consumption
34	Hydro	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption

IPUC Case No. AVU-E-09-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation	
	Production O&M (continued)				
1	Water for Power (536)	P = Production	Energy	E02	Annual Generation Level Consumption
2	Other (Coyote Springs)	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
3	Other Fuel (547)	P = Production	Energy	E02	Annual Generation Level Consumption
4	Other	P = Production	Demand	D01	Coincident Peak Demand
5	Purchased Power and Other Expenses (555 and 557)	P = Production	Demand/Energy from Production Plant	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
6	System Control & Misc (556)	P = Production	Energy	E02	Annual Generation Level Consumption
	Transmission O&M				
7	All Transmission	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
	Distribution O&M				
8	580 OP Super & Engineering	D = Distribution	Demand/Customer from Other Dist Op Exp	S16	Sum of Other Distribution Operating Expenses
9	581 Load Dispatching	D = Distribution	Demand	D02	Non-coincident Peak Demand
10	582 Station Expenses	D = Distribution	Demand	S09	Sum of Account 362 Station Equipment
11	583 Overhead Lines	D = Distribution	Demand	S10	Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
12	584 Underground Lines	D = Distribution	Demand	S11	Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
13	585 Street Lights	D = Distribution	Customer	S15	Sum of Account 373 Street Light and Signal Systems
14	586 Meters	D = Distribution	Customer	S14	Sum of Account 370 Meters
15	587 Customer Installations	D = Distribution	Customer	S13	Sum of Account 369 Services
16	588 Misc Operating Expense	D = Distribution	Demand/Customer from Other Dist Op Exp	S16	Sum of Other Distribution Operating Expenses
17	589 Rents	D = Distribution	Demand	D02	Non-coincident Peak Demand
18	590 MT Super & Engineering	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17	Sum of Other Distribution Maintenance Expenses
19	591 MT of Structures	D = Distribution	Demand	S08	Sum of Account 361 Structures & Improvements
20	592 MT of Station Equipment	D = Distribution	Demand	S09	Sum of Account 362 Station Equipment
21	593 MT of Overhead Lines	D = Distribution	Demand	S10	Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
22	594 MT of Underground Lines	D = Distribution	Demand	S11	Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
23	595 MT of Line Transformers	D = Distribution	Demand	S12	Sum of Account 368 Line Transformers
24	596 MT of Street Lights	D = Distribution	Customer	S15	Sum of Account 373 Street Light and Signal Systems
25	597 MT of Meters	D = Distribution	Customer	S14	Sum of Account 370 Meters
26	598 Misc Maintenance Expense	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17	Sum of Other Distribution Maintenance Expenses
	Customer Accounts Expenses				
27	901 Supervision	C = Customer Relations	Customer	S18	Sum of Other Customer Accounts Expenses Excluding Uncollectibles
28	902 Meter Reading	C = Customer Relations	Customer	C03	Customers Weighted by Estimated Meter Reading Time
29	903 Customer Records & Collections	C = Customer Relations	Customer	C01/C06	All Customers unweighted / Direct Assign Handbilled Cust
30	904 Uncollectible Accounts	R = Revenue Conversion	Revenue	R01	Retail Sales Revenue
31	905 Misc Cust Accounts	C = Customer Relations	Customer	C01	All Customers unweighted
	Customer Service & Info Expenses				
32	907 Supervision	C = Customer Relations	Customer	C01	All Customers unweighted
33	908 Customer Assistance	C = Customer Relations	Customer	C01	All Customers unweighted
34	908 DSM Amortization Expenses	DSM	Demand/Energy from Production Plant	S01	Sum of Production Plant
35	909 Advertising	C = Customer Relations	Customer	C01	All Customers unweighted
36	910 Misc Cust Service & Info	C = Customer Relations	Customer	C01	All Customers unweighted
	Sales Expenses				
37	911 - 916	C = Customer Relations	Energy	E02	Annual Generation Level Consumption

IPUC Case No. AVU-E-09-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 - 927 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
2	920 - 927 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
3	920 - 927 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
4	920 - 927 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01 All Customers unweighted
5	920 - 935 Assigned to Other	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
6	928 FERC Commission Fees	P = Production	Energy	E02 Annual Generation Level Consumption
7	928 IPUC Commission Fees	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
8	928 CAPAI Intervenor Funding	O=Other	Customer	C07 Direct Assignment to Residential Customers
	Depreciation & Amortization Expense			
9	Intangible	P/T/O	Demand/Energy/Customer as in related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
10	Production	P = Production	Demand/Energy as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
11	Transmission	T = Transmission	Demand/Energy as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
12	Distribution	D = Distribution	Demand/Customer as in related Plant	D02/D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
13	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Taxes			
14	Property Tax	P/T/D/O	Demand/Energy/Customer from Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
15	State kWh Generation Taxes	P = Production	Demand/Energy by Combo Peak Credits & Energy	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
16	Misc Production Taxes	P = Production	Demand/Energy by Combo Peak Credits & Energy	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
17	Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
18	Idaho State Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
19	Federal Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
20	Deferred FIT	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
	Other Income Related Items			
21	CS2 Levelized Return and Boulder Write-off Amort.	P = Production	Demand/Energy as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Operating Revenues			
22	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
23	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
24	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
25	Sales of Water & Water Power (453)	P = Production	Demand	D01 Coincident Peak Demand
26	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
27	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
28	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
29	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
30	Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
31	Optional Renewable Revenue (Sch 95)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
32	Montana Retail Revenue	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Salaries & Wages (allocation factor input)			
	Operation & Maintenance Expenses			
33	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
34	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
35	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
36	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
37	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
38	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
39	Admin & General Total	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers

Sumcost
Scenario: Company Base Case
AVU-E-04-01 Method

AVISTA UTILITIES
Cost of Service Basic Summary
For the Twelve Months Ended September 30, 2008

Idaho Jurisdiction
Electric Utility

01-15-09

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service Potlatch Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Plant In Service									
1	Production Plant		373,731,000	135,227,560	37,650,169	75,194,994	32,149,197	86,363,517	5,962,243	1,183,321
2	Transmission Plant		160,359,000	57,376,174	15,974,374	32,342,771	13,863,648	37,689,700	2,584,411	527,923
3	Distribution Plant		391,018,000	197,358,427	61,571,178	91,364,302	10,733,997	2,156,602	8,513,166	19,320,328
4	Intangible Plant		39,605,000	15,741,657	4,230,439	7,550,082	3,059,674	8,136,299	635,089	251,761
5	General Plant		61,178,000	32,454,852	8,011,877	9,394,461	2,838,928	6,495,775	964,439	1,017,668
6	Total Plant In Service		1,025,891,000	438,158,669	127,438,037	215,846,610	62,645,443	140,841,892	18,659,348	22,301,001
	Accum Depreciation									
7	Production Plant		(146,687,000)	(52,857,182)	(14,716,423)	(29,540,070)	(12,641,759)	(34,111,303)	(2,348,989)	(471,275)
8	Transmission Plant		(55,770,000)	(19,954,410)	(5,555,602)	(11,248,239)	(4,821,529)	(13,107,805)	(898,812)	(183,602)
9	Distribution Plant		(121,422,000)	(60,622,702)	(17,696,227)	(28,258,437)	(3,147,094)	(689,459)	(2,423,039)	(8,585,042)
10	Intangible Plant		(6,504,000)	(3,204,666)	(807,144)	(1,067,179)	(358,755)	(873,971)	(103,044)	(89,241)
11	General Plant		(26,764,000)	(14,198,268)	(3,505,016)	(4,109,865)	(1,241,967)	(2,841,756)	(421,920)	(445,207)
12	Total Accumulated Depreciation		(357,147,000)	(150,837,228)	(42,280,413)	(74,223,790)	(22,211,105)	(51,624,294)	(6,195,804)	(9,774,366)
13	Net Plant		668,744,000	287,321,441	85,157,624	141,622,820	40,434,338	89,217,598	12,463,544	12,526,635
14	Accumulated Deferred FIT		(94,277,000)	(39,954,758)	(11,494,640)	(19,546,335)	(5,961,672)	(13,794,122)	(1,683,524)	(1,841,948)
15	Miscellaneous Rate Base		2,967,000	615,534	238,461	777,855	342,392	931,229	52,419	9,109
16	Total Rate Base		577,434,000	247,982,217	73,901,445	122,854,339	34,815,058	76,354,705	10,832,439	10,693,796
17	Revenue From Retail Rates		220,252,000	86,358,000	27,841,000	46,634,000	14,497,000	37,941,000	4,139,000	2,842,000
18	Other Operating Revenues		32,908,000	12,105,796	3,395,160	6,669,515	2,746,549	7,285,317	533,843	171,820
19	Total Revenues		253,160,000	98,463,796	31,236,160	53,303,515	17,243,549	45,226,317	4,672,843	3,013,820
	Operating Expenses									
20	Production Expenses		132,634,000	46,952,246	13,071,925	26,812,020	11,520,641	31,666,824	2,157,965	452,380
21	Transmission Expenses		8,348,000	2,986,900	831,597	1,683,706	721,716	1,962,058	134,540	27,483
22	Distribution Expenses		9,626,000	4,628,565	1,334,788	2,266,359	325,069	68,906	183,439	818,875
23	Customer Accounting Expenses		3,484,000	2,571,225	566,133	159,263	37,127	96,155	44,220	9,878
24	Customer Information Expenses		1,537,000	673,650	169,327	260,612	110,134	295,791	23,169	4,319
25	Sales Expenses		235,000	78,937	21,975	48,021	20,867	60,270	3,995	934
26	Admin & General Expenses		21,605,000	11,157,633	2,813,361	3,480,772	1,040,376	2,391,071	349,065	372,722
27	Total O&M Expenses		177,469,000	69,049,156	18,809,104	34,710,752	13,775,929	36,541,075	2,896,393	1,686,591
28	Taxes Other Than Income Taxes		8,751,000	3,527,601	1,022,110	1,837,350	603,320	1,460,444	154,807	145,368
29	Other Income Related Items		(106,000)	(41,853)	(11,655)	(20,903)	(8,744)	(21,069)	(1,550)	(226)
	Depreciation Expense									
30	Production Plant Depreciation		9,335,000	3,397,568	945,964	1,875,801	800,892	2,137,719	148,120	28,936
31	Transmission Plant Depreciation		3,232,000	1,156,404	321,960	651,861	279,419	759,628	52,088	10,640
32	Distribution Plant Depreciation		10,048,000	4,965,162	1,601,384	2,459,029	306,220	51,900	226,182	438,121
33	General Plant Depreciation		4,867,000	2,581,937	637,383	747,374	225,850	516,770	76,726	80,960
34	Amortization Expense		2,256,000	816,171	227,239	453,924	194,079	521,445	35,996	7,147
35	Total Depreciation Expense		29,738,000	12,917,243	3,733,930	6,187,989	1,806,460	3,987,461	539,112	565,805
36	Income Tax		6,445,000	1,704,864	1,851,605	2,307,179	(29,058)	260,845	256,563	93,002
37	Total Operating Expenses		222,297,000	87,157,010	25,405,095	45,022,366	16,147,908	42,228,755	3,845,326	2,490,540
38	Net Income		30,863,000	11,306,786	5,831,065	8,281,149	1,095,641	2,997,562	827,518	523,280
39	Rate of Return		5.34%	4.56%	7.89%	6.74%	3.15%	3.93%	7.64%	4.89%
40	Return Ratio		1.00	0.85	1.48	1.26	0.59	0.73	1.43	0.92
41	Interest Expense		19,055,000	8,183,275	2,438,706	4,054,125	1,148,878	2,519,663	357,464	352,889

File: ID 09 Elec Case / Elec COS Base Case / Sumcost Exhibits

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service Potlatch Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule											
1	Production				135,335,369	47,229,312	14,287,020	28,463,985	11,181,180	31,376,910	2,337,896	459,067
2	Transmission				16,053,522	5,466,355	1,988,733	3,700,280	1,149,015	3,381,242	316,054	51,842
3	Distribution				43,588,275	20,418,928	8,098,923	10,485,385	1,038,469	563,555	1,069,584	1,913,431
4	Common				25,274,833	13,243,404	3,466,324	3,984,350	1,128,335	2,619,293	415,466	417,660
5	Total Current Rate Revenue				220,252,000	86,358,000	27,841,000	46,634,000	14,497,000	37,941,000	4,139,000	2,842,000
	Expressed as $/kWh											
6	Production				$0.03881	$0.04066	$0.04419	$0.04020	$0.03559	$0.03456	$0.03977	$0.03339
7	Transmission				$0.00460	$0.00471	$0.00615	$0.00523	$0.00366	$0.00372	$0.00538	$0.00377
8	Distribution				$0.01250	$0.01758	$0.02505	$0.01481	$0.00331	$0.00062	$0.01819	$0.13919
9	Common				$0.00725	$0.01140	$0.01072	$0.00563	$0.00359	$0.00289	$0.00707	$0.03038
10	Total Current Melded Rates				$0.06316	$0.07435	$0.08610	$0.06587	$0.04614	$0.04179	$0.07040	$0.20674
	Functional Cost Components at Uniform Current Return											
11	Production				136,108,108	48,192,991	13,417,365	27,512,989	11,821,235	32,485,592	2,214,048	463,889
12	Transmission				16,382,662	5,861,688	1,631,981	3,304,215	1,416,344	3,850,471	264,030	53,934
13	Distribution				42,444,209	21,896,635	6,553,913	9,265,498	1,273,644	600,669	875,718	1,978,132
14	Common				25,317,020	13,432,535	3,314,993	3,887,051	1,174,634	2,687,691	399,046	421,070
15	Total Uniform Current Cost				220,252,000	89,383,849	24,918,252	43,969,753	15,685,857	39,624,422	3,752,841	2,917,025
	Expressed as $/kWh											
16	Production				$0.03903	$0.04149	$0.04150	$0.03886	$0.03763	$0.03578	$0.03766	$0.03374
17	Transmission				$0.00470	$0.00505	$0.00505	$0.00467	$0.00451	$0.00424	$0.00449	$0.00392
18	Distribution				$0.01217	$0.01885	$0.02027	$0.01309	$0.00405	$0.00066	$0.01490	$0.14390
19	Common				$0.00726	$0.01156	$0.01025	$0.00549	$0.00374	$0.00296	$0.00679	$0.03063
20	Total Current Uniform Melded Rates				$0.06316	$0.07696	$0.07707	$0.06210	$0.04993	$0.04365	$0.06383	$0.21219
21	**Revenue to Cost Ratio at Current Rates**				1.00	0.97	1.12	1.06	0.92	0.96	1.10	0.97
	Functional Cost Components at Proposed Return by Schedule											
22	Production				147,845,557	51,139,821	15,323,930	30,786,204	12,472,189	35,126,868	2,517,492	479,054
23	Transmission				21,260,938	7,070,669	2,414,124	4,667,478	1,688,248	4,968,408	391,500	60,512
24	Distribution				55,555,541	26,415,660	9,941,193	13,464,381	1,512,844	689,090	1,350,732	2,181,641
25	Common				26,822,964	14,010,850	3,646,753	4,221,937	1,221,720	2,850,635	439,276	431,793
26	Total Proposed Rate Revenue				251,485,000	98,637,000	31,326,000	53,140,000	16,895,000	43,635,000	4,699,000	3,153,000
	Expressed as $/kWh											
27	Production				$0.04239	$0.04403	$0.04739	$0.04348	$0.03970	$0.03869	$0.04282	$0.03485
28	Transmission				$0.00610	$0.00609	$0.00747	$0.00659	$0.00537	$0.00547	$0.00666	$0.00440
29	Distribution				$0.01593	$0.02274	$0.03075	$0.01902	$0.00482	$0.00076	$0.02298	$0.15870
30	Common				$0.00769	$0.01206	$0.01128	$0.00596	$0.00389	$0.00314	$0.00747	$0.03141
31	Total Proposed Melded Rates				$0.07211	$0.08492	$0.09688	$0.07505	$0.05378	$0.04806	$0.07993	$0.22936
	Functional Cost Components at Uniform Requested Return											
32	Production				147,899,815	52,464,728	14,606,708	29,884,869	12,835,036	35,205,453	2,401,957	501,064
33	Transmission				21,280,678	7,614,190	2,119,903	4,292,095	1,839,796	5,001,667	342,968	70,059
34	Distribution				55,407,201	28,447,276	8,666,992	12,308,195	1,646,165	691,720	1,169,879	2,476,973
35	Common				26,897,306	14,270,875	3,521,948	4,129,718	1,247,967	2,855,483	423,959	447,358
36	Total Uniform Cost				251,485,000	102,797,068	28,915,551	50,614,878	17,568,963	43,754,324	4,338,763	3,495,453
	Expressed as $/kWh											
37	Production				$0.04241	$0.04517	$0.04517	$0.04221	$0.04085	$0.03878	$0.04086	$0.03645
38	Transmission				$0.00610	$0.00656	$0.00656	$0.00606	$0.00586	$0.00551	$0.00583	$0.00510
39	Distribution				$0.01589	$0.02449	$0.02680	$0.01738	$0.00524	$0.00076	$0.01990	$0.18018
40	Common				$0.00771	$0.01229	$0.01089	$0.00583	$0.00397	$0.00315	$0.00721	$0.03254
41	Total Uniform Melded Rates				$0.07211	$0.08850	$0.08943	$0.07149	$0.05592	$0.04819	$0.07380	$0.25427
42	**Revenue to Cost Ratio at Proposed Rates**				1.00	0.96	1.08	1.05	0.96	1.00	1.08	0.90
43	**Current Revenue to Proposed Cost Ratio**				**0.88**	**0.84**	**0.96**	**0.92**	**0.83**	**0.87**	**0.95**	**0.81**

AVISTA UTILITIES
Revenue to Cost By Classification Summary
For the Twelve Months Ended September 30, 2008

Idaho Jurisdiction
Electric Utility

01-15-09

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description		System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service Potlatch Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Cost Classifications at Current Return by Schedule									
1	Energy		112,358,195	37,226,967	11,275,647	23,952,392	9,473,564	27,947,486	2,037,651	444,488
2	Demand		88,106,759	35,660,621	12,650,826	22,062,115	5,016,892	9,992,632	1,746,114	977,559
3	Customer		19,787,047	13,470,412	3,914,527	619,493	6,544	882	355,236	1,419,954
4	Total Current Rate Revenue		220,252,000	86,358,000	27,841,000	46,634,000	14,497,000	37,941,000	4,139,000	2,842,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.03222	$0.03205	$0.03487	$0.03383	$0.03015	$0.03078	$0.03466	$0.03233
6	Demand	$/kW/mo	$10.88	$11.47	$13.14	$11.68	$8.63	$7.28	$12.28	$23.56
7	Customer	$/Cust/mo	$13.70	$11.39	$17.26	$35.86	$45.44	$73.53	$23.01	$951.07
	Cost Classifications at Uniform Current Return									
8	Energy		113,127,008	37,999,770	10,578,351	23,116,841	10,045,287	29,013,641	1,923,372	449,747
9	Demand		87,455,196	37,427,884	10,942,955	20,305,813	5,631,907	10,609,724	1,526,930	1,009,983
10	Customer		19,669,795	13,956,195	3,396,945	547,099	8,663	1,057	302,539	1,457,296
11	Total Uniform Current Cost		220,252,000	89,383,849	24,918,252	43,969,753	15,685,857	39,624,422	3,752,841	2,917,025
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.03244	$0.03272	$0.03272	$0.03265	$0.03197	$0.03196	$0.03272	$0.03272
13	Demand	$/kW/mo	$10.80	$12.04	$11.37	$10.75	$9.69	$7.73	$10.74	$24.35
14	Customer	$/Cust/mo	$13.62	$11.80	$14.98	$31.67	$60.16	$88.11	$19.59	$976.09
15	**Revenue to Cost Ratio at Current Rates**		1.00	0.97	1.12	1.06	0.92	0.96	1.10	0.97
	Cost Classifications at Proposed Return by Schedule									
16	Energy		123,312,719	40,362,925	12,107,052	25,992,719	10,626,749	31,553,619	2,203,369	466,286
17	Demand		105,383,881	42,832,335	14,687,265	26,351,002	6,257,432	12,079,907	2,063,973	1,111,966
18	Customer		22,788,400	15,441,740	4,531,682	796,279	10,819	1,474	431,657	1,574,748
19	Total Proposed Rate Revenue		251,485,000	98,637,000	31,326,000	53,140,000	16,895,000	43,635,000	4,699,000	3,153,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.03536	$0.03475	$0.03744	$0.03671	$0.03382	$0.03476	$0.03748	$0.03392
21	Demand	$/kW/mo	$13.01	$13.78	$15.26	$13.95	$10.76	$8.80	$14.51	$26.80
22	Customer	$/Cust/mo	$15.78	$13.06	$19.98	$46.10	$75.13	$122.84	$27.96	$1,054.75
	Cost Classifications at Uniform Requested Return									
23	Energy		123,325,286	41,425,408	11,531,978	25,200,799	10,950,859	31,629,189	2,096,762	490,291
24	Demand		105,076,407	45,262,045	13,278,750	24,686,413	6,606,083	12,123,648	1,859,503	1,259,964
25	Customer		23,083,307	16,109,616	4,104,823	727,666	12,021	1,486	382,498	1,745,198
26	Total Uniform Cost		251,485,000	102,797,068	28,915,551	50,614,878	17,568,963	43,754,324	4,338,763	3,495,453
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.03536	$0.03567	$0.03567	$0.03559	$0.03486	$0.03484	$0.03567	$0.03567
28	Demand	$/kW/mo	$12.97	$14.56	$13.79	$13.07	$11.36	$8.83	$13.08	$30.37
29	Customer	$/Cust/mo	$15.99	$13.62	$18.10	$42.13	$83.48	$123.87	$24.77	$1,168.92
30	**Revenue to Cost Ratio at Proposed Rates**		1.00	0.96	1.08	1.05	0.96	1.00	1.08	0.90
31	**Current Revenue to Proposed Cost Ratio**		**0.88**	**0.84**	**0.96**	**0.92**	**0.83**	**0.87**	**0.95**	**0.81**

File: ID 09 Elec Case / Elec COS Base Case / Sumcost Exhibits

AVISTA UTILITIES
Demand Allocator Sensitivity Analysis
Case No. AVU-E-09-01

Line No	(b) (c) (d) (e) Description	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service Potlatch Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Base Case								
1	Total Rate Base	577,434,000	247,982,217	73,901,445	122,854,339	34,815,058	76,354,705	10,832,439	10,693,796
2	Net Income at Present Rates	30,863,000	11,308,001	5,830,726	8,280,751	1,095,521	2,997,287	827,477	523,237
3	Rate of Return	5.34%	4.56%	7.89%	6.74%	3.15%	3.93%	7.64%	4.89%
4	Return Ratio-Base Case	1.00	0.85	1.48	1.26	0.59	0.73	1.43	0.92
	Scenario 1 - Non-Coincident Peak Twice Base Case								
5	Total Rate Base	577,434,000	248,031,850	73,916,813	122,884,497	34,785,870	76,285,802	10,834,709	10,694,458
6	Net Income at Present Rates	30,863,000	11,302,229	5,829,654	8,278,379	1,098,321	3,003,889	827,309	523,219
7	Rate of Return	5.34%	4.56%	7.89%	6.74%	3.16%	3.94%	7.64%	4.89%
8	Return Ratio-Scenario 1	1.00	0.85	1.48	1.26	0.59	0.74	1.43	0.92
	Scenario 2 - Over-Unity Non-Coincident Peak Increased and Under-Unity Non-Coincident Peak Decreased								
9	Total Rate Base	577,434,000	234,614,015	78,297,005	131,294,125	34,815,238	76,355,128	11,481,871	10,576,618
10	Net Income at Present Rates	30,863,000	12,165,221	5,550,549	7,737,194	1,095,624	2,997,523	786,072	530,817
11	Rate of Return	5.34%	5.19%	7.09%	5.89%	3.15%	3.93%	6.85%	5.02%
12	Return Ratio-Scenario 2	1.00	0.97	1.33	1.10	0.59	0.73	1.28	0.94
	Scenario 3 - Coincident Peaks 6.25% of Peak Days								
13	Total Rate Base	577,434,000	246,912,552	73,726,366	123,742,634	34,815,038	76,354,656	11,188,958	10,693,795
14	Net Income at Present Rates	30,863,000	11,517,044	5,865,479	8,106,542	1,095,645	2,997,571	757,439	523,280
15	Rate of Return	5.34%	4.66%	7.96%	6.55%	3.15%	3.93%	6.77%	4.89%
16	Return Ratio-Scenario 3	1.00	0.87	1.49	1.23	0.59	0.73	1.27	0.92
	Scenario 4 - Over-Unity Coincident Peak Increased and Under-Unity Coincident Peak Decreased								
17	Total Rate Base	577,434,000	242,970,806	75,626,997	125,938,803	34,815,038	76,354,656	11,060,570	10,667,130
18	Net Income at Present Rates	30,863,000	12,291,850	5,491,884	7,674,854	1,095,645	2,997,571	782,675	528,521
19	Rate of Return	5.34%	5.06%	7.26%	6.09%	3.15%	3.93%	7.08%	4.95%
20	Return Ratio-Scenario 4	1.00	0.95	1.36	1.14	0.59	0.73	1.32	0.93

NATURAL GAS COST OF SERVICE STUDY

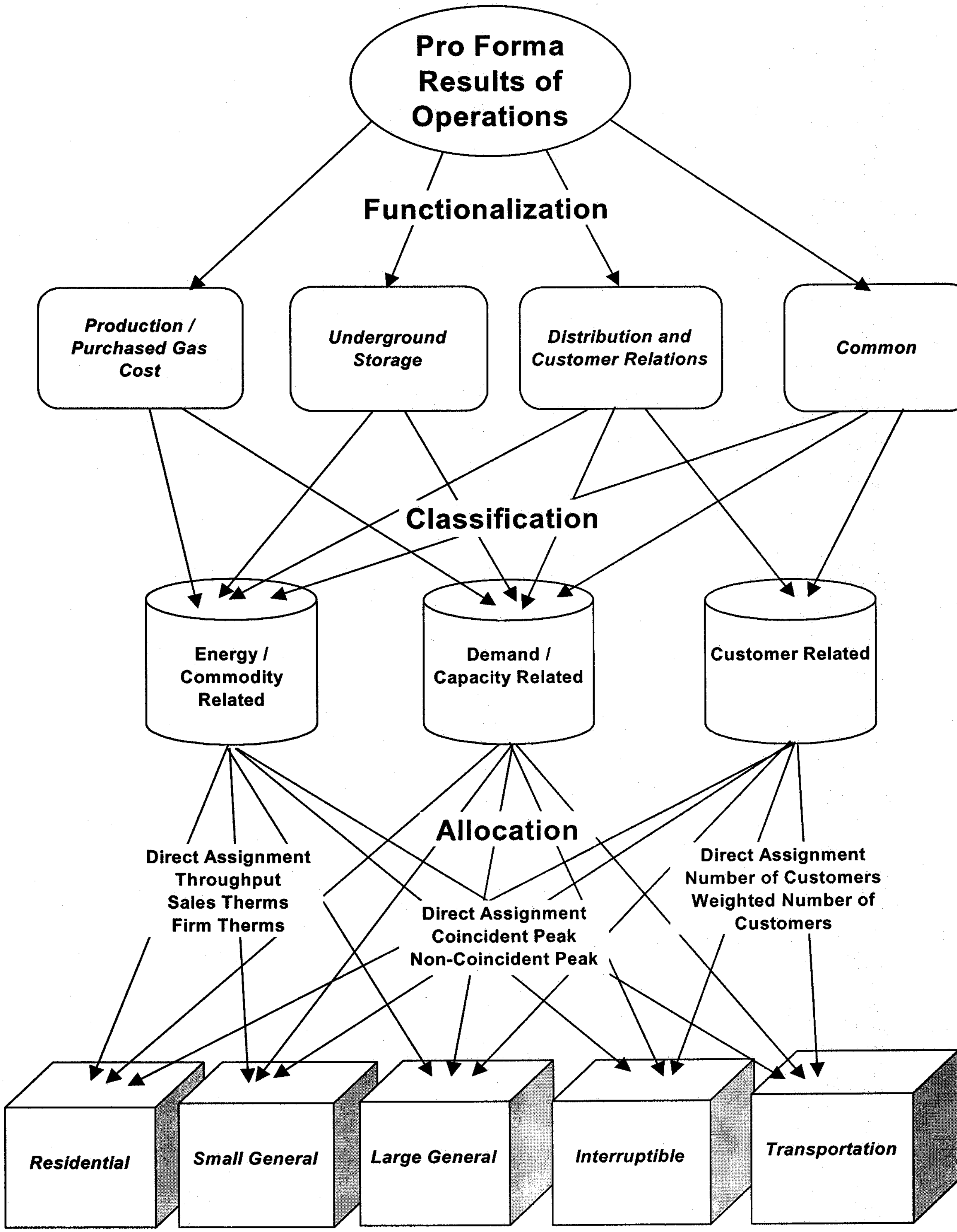
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart.

First, the expenses and rate base associated with the natural gas system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, underground storage, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items are classified into three primary cost components: Demand, commodity or customer related. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to system peak demand. Commodity (energy) related costs are allocated based on each rate schedule's share of commodity consumption. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

NATURAL GAS COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

Exhibit No. 11
Case No. AVU-G-09-01
T. Knox, Avista
Schedule 5, p. 2 of 9

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production - Purchased Gas Costs

The Company has no natural gas production facilities serving the Idaho jurisdiction. The natural gas costs included in the production function include the cost of gas purchased to serve sales customers, pipeline transportation to get it to our system, and expenses of the gas supply department.

The demand and commodity components of account 804 have been determined directly from the weighted average cost of gas (WACOG) approved in the most recent purchased gas adjustment (PGA) filing effective October 1, 2008. The January 6, 2009 gas cost reduction to customer charges was accomplished through Schedule 155 which is excluded from base revenues. The allocation of these costs agrees with the gas costs computation used to determine pro forma results of operations.

The expenses of the gas supply department recorded in account 813 are classified as commodity related costs. The gas scheduling process includes transportation customers, so estimated scheduling dispatch labor expenses are allocated by throughput. The remaining gas supply department expenses are allocated by sales volumes.

Underground Storage

Underground storage rate base, operating and maintenance expenses are classified as commodity related and allocated to customer groups by winter throughput. This approach was proposed by commission Staff and accepted by the Idaho Public Utilities Commission in Case No. AVU-G-04-01.

Distribution Facilities Classification (Peak and Average)

Distribution mains and regulator station equipment (both general use and city gate stations) are classified Demand and Commodity using the peak and average ratio for the distribution system. Peak demand is defined as the average of the five-day sustained peaks from the most recent three years. Average daily load is calculated by dividing annual throughput by 365 (days in the year). The average daily load is divided by peak load to arrive at the system load factor of 37%. This proportion is classified as commodity related. The remaining 63% is classified as demand related. Meters, services and industrial measuring & regulating equipment are classified as customer related distribution plant. Distribution operating and maintenance expenses are classified (and allocated) in relation to the plant accounts they are associated with.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part these costs are classified as customer related. Exceptions include uncollectible accounts expense, which is considered separately as a revenue conversion item, and Demand Side Management amortization expense recorded in Account 908. The demand side management investment costs and amortization expense are included with the distribution function and classified to demand and commodity by the peak and average ratio.

Distribution Cost Allocation

Demand related distribution costs are allocated to customer groups (rate schedules) by each groups' contribution to the three year average five-day sustained peak. Commodity related distribution costs are allocated to customer groups by annual throughput. Distribution main investment has been segregated into large and small mains. Small mains are defined as less than four inches, with large mains being four inches or greater. The small main costs use the same demand and commodity data, but large usage customers (Schedules 131, and 146) that connect to large system mains have been excluded from the allocations.

Most customer related costs are allocated by the annualized number of customers billed during the test period. Meter investment costs are allocated using the number of customers weighted by the relative current cost of meters in service at December 31, 2007. Services investment costs are allocated using the number of customers weighted by the relative current cost of typical service installations. Industrial measuring and regulating equipment investment costs are allocated by number of turbine meters which effectively excludes small usage customers.

Administrative and General Costs

General and intangible rate base items are allocated by the sum of Underground Storage and Distribution plant. Administrative and general expenses are segregated into plant related, labor related, revenue related and other. The plant related items are allocated based on total plant in service. Labor related items are allocated by operating and maintenance labor expense. Revenue related items are allocated by pro forma revenue. Other administrative and general expenses are allocated 50% by annual throughput (classified commodity related) and 50% by the sum of operating and maintenance expenses not including purchased gas cost or administrative & general expenses. Whenever costs are allocated by sums of other items within the study, classifications are imputed from the relationship embedded in the summed items.

Special Contract Customer Revenue

Three special contract customers receive transportation service from the Company. Rates for these customers were individually negotiated to cover any incremental costs and retain some contribution to margin. The rates for these customers are not being adjusted in this case. The revenue from these special contract customers has been segregated from general rate revenue and allocated back to all the other rate classes by relative rate base. In treating these revenues like other operating revenues their system contribution reduces costs for all rate schedules.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax less interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to the component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category b that ratio. Similarly, income tax items have been assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case natural gas cost of service study.

IPUC Case No. AVU-G-09-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Underground Storage Plant			
1	350 - 357 Underground Storage	Underground Storage	Commodity	E08 Winter throughput
	Distribution Plant			
2	374 Land	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
3	375 Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
4	376(S) Small Mains	Distribution	Demand/Commodity by Peak & Average	D02/E06 Coincident peak, annual therms (both excl lg use cust)
5	376(L) Large Mains	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
6	378 M&R General	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
7	379 M&R City Gate	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
8	380 Services	Distribution	Customer	C02, Customers weighted by current typical service cost
9	381 Meters	Distribution	Customer	C03, Customers weighted by average current meter cost
10	385 Industrial M&R	Distribution	Customer	C06, Large use customers
11	387 Other	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
	General Plant			
12	389-399 All General Plant	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Intangible Plant			
13	303 Misc Intangible Plant	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
14	303 Computer Software	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Reserve for Depreciation			
15	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
16	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
18	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Other Rate Base			
19	Accumulated Deferred FIT	All	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
20	Constuction Advances	Distribution	Customer	C10 Residential only
21	Gas Inventory	Underground Storage	Commodity from Underground Storage Plant	S14 Sum of Underground Storage Plant in Service
22	Gain on Sale of Office Bldg	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
23	DSM Investment	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
	Purchased Gas Expenses			
24	804 Purchased Gas Cost	Production	Demand/Commodity from PGA Tracker WACOG	D05/E07 PGA Demand / PGA Commodity
25	813 Other Gas Expenses	Production	Commodity	E01/E04 Annual Throughput / Annual Sales Therms
	Underground Storage O&M			
26	814 - 837 Underground Storage Exp	Underground Storage	Commodity	E08 Winter throughput

IPUC Case No. AVU-G-09-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Distribution O&M			
1	870 OP Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
2	871 Load Dispatching	Distribution	Commodity	E01 Annual throughput
3	874 Mains & Services	Distribution	Demand/Commodity/Customer from related plant	S06 Sum of Mains and Services Plant in Service
4	875 M&R Station - General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
5	876 M&R Station - Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
6	877 M&R Station - City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
7	878 Meter & House Regulator	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
8	879 Customer Installations	Distribution	Customer	C05, Customers weighted by average current meter cost
9	880 Other OP Expenses	Distribution	Demand/Commodity/Customer from other dist expens	S04 Sum of Accounts 870 - 879 and 881 - 894
10	881 Rents	Distribution	Demand/Commodity/Customer from other dist expens	S04 Sum of Accounts 870 - 879 and 881 - 894
11	885 MT Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
12	886 MT of Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
13	887 MT of Mains	Distribution	Demand/Commodity from related plant	S21 Sum of Distribution Mains Plant in Service
14	889 MT of M&R General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
15	890 MT of M&R Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
16	891 MT of M&R City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
17	892 MT of Services	Distribution	Customer from related plant	S20 Sum of Services Plant in Services
18	893 MT of Meters & Hs Reg	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
19	894 MT of Other Equipment	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
	Customer Accounting Expenses			
20	901 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
21	902 Meter Reading	Customer Relations	Customer	C01 All customers (unweighted)
22	903 Customer Records & Collections	Customer Relations	Customer	C01 All customers (unweighted)
23	904 Uncollectible Accounts	Revenue Conversion	Revenue	R03 Retail Sales Revenue
24	905 Misc Cust Accounts	Customer Relations	Customer	C01 All customers (unweighted)
	Customer Service & Info Expenses			
25	907 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
26	908 Customer Assistance	Customer Relations	Customer	C01 All customers (unweighted)
27	908 DSM Amortization	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
28	909 Advertising	Customer Relations	Customer	C01 All customers (unweighted)
29	910 Misc Cust Service & Info	Customer Relations	Customer	C01 All customers (unweighted)
	Sales Expenses			
30	911 - 916 Sales Expenses	Customer Relations	Customer	C01 All customers (unweighted)

IPUC Case No. AVU-G-09-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 Salaries	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
2	921 Office Supplies	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
3	922 Admin Expense Transferred - Credi	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
4	923 Outside Services	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
5	924 Property Insurance	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
6	925 Injuries & Damages	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
7	926 Pensions & Benefits	Common	Demand/Commodity/Customer from Labpr O&M	S13 O&M Labor Expense
8	927 Franchise Requirements	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
9	928 Regulatory Commision	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
10	928 Commission Fees	Revenue Conversion	Revenue	R01 Retail Sales Revenue
11	930 Miscellaneous General	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
12	931 Rents	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
13	935 MT of General Plant	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
	Depreciation Expense			
14	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
15	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
16	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Taxes			
18	Property Tax	All	Demand/Commodity/Customer from related plant	S14/S15/S16 Sum of UG Plant/Sum of Dist Plant/Sum of Gen Plant
19	Miscellaneous Dist Tax	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
20	State Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
21	Federal Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
22	Deferred FIT	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
23	ITC	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
	Operating Revenues			
24	Revenue from Rates	Revenue	Revenue	Pro Forma Revenue per Revenue Study
25	Special Contract Revenue	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
26	Off System Sales	Production	Commodity from PGA Tracker	E04 Sales Therms
27	Miscellaneous Service Revenue	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
28	Rent From Gas Property	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
29	Other Gas Revenue	Underground Storage	Commodity from Underground Storage Plant	S14 Sum of Underground Storage Plant in Service

Sumcost
Company Base Case
AVU-G-04-01 Method

AVISTA UTILITIES
Cost of Service General Summary
For the Year Ended September 30, 2008

Natural Gas Utility
Idaho Jurisdiction

13-Jan-09

	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
	Description				System Total	Residential Service Sch 101	Small Firm Service Sch 111	Interrupt Service Sch 131	Transport Service Sch 146
	Plant In Service								
1	Production Plant								
2	Underground Storage Plant				9,089,000	6,886,160	1,958,969	38,051	205,820
3	Distribution Plant				130,352,000	108,934,756	20,079,764	314,421	1,023,059
4	Intangible Plant				1,653,000	1,373,897	260,548	4,158	14,397
5	General Plant				12,589,000	10,456,534	1,989,699	31,822	110,946
6	Total Plant In Service				153,683,000	127,651,347	24,288,980	388,451	1,354,222
	Accum Depreciation								
7	Production Plant								
8	Underground Storage Plant				(3,172,000)	(2,403,224)	(683,667)	(13,280)	(71,830)
9	Distribution Plant				(44,780,000)	(37,983,003)	(6,356,878)	(102,649)	(337,470)
10	Intangible Plant				(647,000)	(537,526)	(102,163)	(1,633)	(5,679)
11	General Plant				(4,489,000)	(3,728,603)	(709,489)	(11,347)	(39,561)
12	Total Accumulated Depreciation				(53,088,000)	(44,652,356)	(7,852,197)	(128,908)	(454,539)
13	Net Plant				100,595,000	82,998,991	16,436,783	259,543	899,683
14	Accumlulated Deferred FIT				(15,052,000)	(12,502,411)	(2,378,908)	(38,046)	(132,635)
15	Miscellaneous Rate Base				4,948,000	3,723,232	1,086,406	21,178	117,184
16	Total Rate Base				90,491,000	74,219,812	15,144,281	242,676	884,231
17	Revenue From Retail Rates				91,767,000	70,716,433	20,333,806	396,352	320,409
18	Other Operating Revenues				147,000	120,770	24,428	391	1,411
19	Total Revenues				91,914,000	70,837,202	20,358,235	396,743	321,820
	Operating Expenses								
20	Purchased Gas Costs				66,637,000	49,715,037	16,583,726	334,703	3,534
21	Underground Storage Expenses				167,000	126,525	35,994	699	3,782
22	Distribution Expenses				4,087,000	3,347,026	677,958	6,596	55,419
23	Customer Accounting Expenses				1,869,000	1,795,913	71,107	1,042	938
24	Customer Information Expenses				244,000	217,182	23,238	433	3,148
25	Sales Expenses				194,000	191,749	2,235	3	14
26	Admin & General Expenses				5,034,000	4,010,109	909,268	16,707	97,916
27	Total O&M Expenses				78,232,000	59,403,542	18,303,526	360,183	164,749
28	Taxes Other Than Income Taxes				906,000	749,676	145,443	2,355	8,526
29	Depreciation Expense								
30	Underground Storage Plant Depr				136,000	103,039	29,312	569	3,080
31	Distribution Plant Depreciation				2,830,000	2,388,256	415,324	5,079	21,341
32	General Plant Depreciation				868,000	720,968	137,188	2,194	7,650
33	Amortization of Intangible Plant				307,000	255,017	48,506	776	2,702
34	Total Depr & Amort Expense				4,141,000	3,467,280	630,329	8,618	34,772
35	Income Tax				2,422,000	2,044,109	334,084	7,537	36,270
36	Total Operating Expenses				85,701,000	65,664,606	19,413,383	378,693	244,318
37	Net Income				6,213,000	5,172,596	944,851	18,050	77,503
38	Rate of Return				6.87%	6.97%	6.24%	7.44%	8.76%
39	Return Ratio				1.00	1.02	0.91	1.08	1.28
40	Interest Expense				2,986,000	2,449,087	499,727	8,008	29,178

Sumcost	AVISTA UTILITIES	Natural Gas Utility	
Company Base Case	Summary by Function with Margin Analysis	Idaho Jurisdiction	13-Jan-09
AVU-G-04-01 Method	For the Year Ended September 30, 2008		

	(b) (c) (d) (e)	(f)	(g)	(h)	(j)	(k)
	Description	System Total	Residential Service Sch 101	Small Firm Service Sch 111	Interrupt Service Sch 131	Transport Service Sch 146
	Functional Cost Components at Current Rates					
1	Production	66,980,783	49,971,519	16,669,282	336,430	3,552
2	Underground Storage	1,326,263	1,019,898	262,857	5,976	37,532
3	Distribution	16,711,333	14,266,690	2,248,957	33,119	162,567
4	Common	6,748,621	5,458,325	1,152,711	20,828	116,757
5	**Total Current Rate Revenue**	**91,767,000**	**70,716,433**	**20,333,806**	**396,352**	**320,409**
6	Exclude Cost of Gas w / Revenue Exp.	66,589,776	49,682,612	16,572,910	334,254	0
7	**Total Margin Revenue at Current Rates**	**25,177,224**	**21,033,820**	**3,760,897**	**62,098**	**320,409**
	Margin per Therm at Current Rates					
8	Production	$0.00501	$0.00514	$0.00514	$0.00514	$0.00127
9	Underground Storage	$0.01698	$0.01816	$0.01403	$0.01413	$0.01346
10	Distribution	$0.21396	$0.25404	$0.12005	$0.07833	$0.05831
11	Common	$0.08641	$0.09719	$0.06153	$0.04926	$0.04188
12	Total Current Margin Melded Rate per Therr	**$0.32236**	**$0.37454**	**$0.20076**	**$0.14686**	**$0.11492**
	Functional Cost Components at Uniform Current Return					
13	Production	66,980,783	49,971,519	16,669,282	336,430	3,552
14	Underground Storage	1,328,232	1,006,317	286,276	5,561	30,078
15	Distribution	16,710,022	14,156,513	2,379,550	31,282	142,676
16	Common	6,747,963	5,447,026	1,165,745	20,637	114,555
17	Total Uniform Current Cost	**91,767,000**	**70,581,375**	**20,500,853**	**393,910**	**290,861**
18	Exclude Cost of Gas w / Revenue Exp.	66,589,776	49,682,612	16,572,910	334,254	0
19	Total Uniform Current Margin	**25,177,224**	**20,898,763**	**3,927,944**	**59,656**	**290,861**
	Margin per Therm at Uniform Current Return					
20	Production	$0.00501	$0.00514	$0.00514	$0.00514	$0.00127
21	Underground Storage	$0.01701	$0.01792	$0.01528	$0.01315	$0.01079
22	Distribution	$0.21395	$0.25208	$0.12702	$0.07398	$0.05117
23	Common	$0.08640	$0.09699	$0.06223	$0.04881	$0.04109
24	Total Current Uniform Margin Melded Rate p	**$0.32236**	**$0.37213**	**$0.20968**	**$0.14109**	**$0.10433**
25	**Margin to Cost Ratio at Current Rates**	**1.00**	**1.01**	**0.96**	**1.04**	**1.10**
	Functional Cost Components at Proposed Rates					
26	Production	66,980,740	49,971,487	16,669,271	336,429	3,552
27	Underground Storage	1,627,837	1,239,650	334,732	7,124	46,331
28	Distribution	18,923,444	16,049,439	2,649,757	38,202	186,047
29	Common	6,974,584	5,641,160	1,192,713	21,354	119,357
30	**Total Proposed Rate Revenue**	**94,506,605**	**72,901,735**	**20,846,474**	**403,109**	**355,287**
31	Exclude Cost of Gas w / Revenue Exp.	66,589,733	49,682,580	16,572,899	334,254	0
32	**Total Margin Revenue at Proposed Rates**	**27,916,872**	**23,219,155**	**4,273,575**	**68,855**	**355,287**
	Margin per Therm at Proposed Rates					
33	Production	$0.00501	$0.00514	$0.00514	$0.00514	$0.00127
34	Underground Storage	$0.02084	$0.02207	$0.01787	$0.01685	$0.01662
35	Distribution	$0.24229	$0.28579	$0.14145	$0.09035	$0.06673
36	Common	$0.08930	$0.10045	$0.06367	$0.05050	$0.04281
37	Total Proposed Margin Melded Rate per Th	**$0.35744**	**$0.41345**	**$0.22813**	**$0.16284**	**$0.12743**
	Functional Cost Components at Uniform Proposed Return					
38	Production	66,980,740	49,971,487	16,669,271	336,429	3,552
39	Underground Storage	1,626,470	1,232,273	350,556	6,809	36,831
40	Distribution	18,925,094	15,989,593	2,737,994	36,809	160,698
41	Common	6,974,302	5,635,022	1,201,520	21,210	116,550
42	Total Uniform Proposed Cost	**94,506,605**	**72,828,375**	**20,959,341**	**401,257**	**317,632**
43	Exclude Cost of Gas w / Revenue Exp.	66,589,733	49,682,580	16,572,899	334,254	0
44	Total Uniform Proposed Margin	**27,916,872**	**23,145,795**	**4,386,443**	**67,003**	**317,632**
	Margin per Therm at Uniform Proposed Return					
45	Production	$0.00501	$0.00514	$0.00514	$0.00514	$0.00127
46	Underground Storage	$0.02082	$0.02194	$0.01871	$0.01610	$0.01321
47	Distribution	$0.24231	$0.28472	$0.14616	$0.08705	$0.05764
48	Common	$0.08930	$0.10034	$0.06414	$0.05016	$0.04180
49	Total Proposed Uniform Margin Melded Rat	**$0.35744**	**$0.41215**	**$0.23415**	**$0.15846**	**$0.11393**
50	**Margin to Cost Ratio at Proposed Rates**	**1.00**	**1.00**	**0.97**	**1.03**	**1.12**
51	**Current Margin to Proposed Cost Ratio**	**0.90**	**0.91**	**0.86**	**0.93**	**1.01**

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Cost by Classification at Current Return by Schedule								
1	Commodity				66,708,989	49,720,709	16,447,538	373,052	167,690
2	Demand				12,468,929	9,579,188	2,799,599	21,022	69,120
3	Customer				12,589,082	11,416,536	1,086,670	2,278	83,598
4	Total Current Rate Revenue				91,767,000	70,716,433	20,333,806	396,352	320,409
	Revenue per Therm at Current Rates								
5	Commodity				$0.85411	$0.88535	$0.87798	$0.88228	$0.06015
6	Demand				$0.15965	$0.17057	$0.14944	$0.04972	$0.02479
7	Customer				$0.16119	$0.20329	$0.05801	$0.00539	$0.02998
8	Total Revenue per Therm at Current Rates				$1.17494	$1.25922	$1.08544	$0.93738	$0.11492
	Cost per Unit at Current Rates								
9	Commodity Cost per Therm				$0.85411	$0.88535	$0.87798	$0.88228	$0.06015
10	Demand Cost per Peak Day Therms				$21.39	$21.36	$24.18	$10.02	$4.18
11	Customer Cost per Customer per Month				$14.60	$13.40	$109.42	$189.80	$1,393.30
	Cost by Classification at Uniform Current Return								
12	Commodity				66,725,488	49,684,882	16,515,738	371,719	153,150
13	Demand				12,480,879	9,539,589	2,861,569	19,992	59,729
14	Customer				12,560,632	11,356,904	1,123,547	2,199	77,982
15	Total Uniform Current Cost				91,767,000	70,581,375	20,500,853	393,910	290,861
	Cost per Therm at Current Return								
16	Commodity				$0.85432	$0.88472	$0.88162	$0.87912	$0.05493
17	Demand				$0.15980	$0.16987	$0.15275	$0.04728	$0.02142
18	Customer				$0.16082	$0.20223	$0.05998	$0.00520	$0.02797
19	Total Cost per Therm at Current Return				$1.17494	$1.25681	$1.09435	$0.93161	$0.10433
	Cost per Unit at Uniform Current Return								
20	Commodity Cost per Therm				$0.85432	$0.88472	$0.88162	$0.87912	$0.05493
21	Demand Cost per Peak Day Therms				$21.41	$21.27	$24.72	$9.53	$3.61
22	Customer Cost per Customer per Month				$14.57	$13.33	$113.14	$183.26	$1,299.71
23	**Revenue to Cost Ratio at Current Rates**				**1.00**	**1.00**	**0.99**	**1.01**	**1.10**
	Cost by Classification at Proposed Return by Schedule								
24	Commodity				67,518,814	50,300,380	16,656,837	376,743	184,853
25	Demand				13,313,785	10,219,918	2,989,788	23,872	80,206
26	Customer				13,674,006	12,381,437	1,199,848	2,494	90,227
27	Total Proposed Rate Revenue				94,506,605	72,901,735	20,846,474	403,109	355,287
	Revenue per Therm at Proposed Rates								
28	Commodity				$0.86448	$0.89568	$0.88916	$0.89101	$0.06630
29	Demand				$0.17046	$0.18198	$0.15960	$0.05646	$0.02877
30	Customer				$0.17508	$0.22047	$0.06405	$0.00590	$0.03236
31	Total Revenue per Therm at Proposed Rate				$1.21002	$1.29813	$1.11280	$0.95336	$0.12743
	Cost per Unit at Proposed Rates								
32	Commodity Cost per Therm				$0.86448	$0.89568	$0.88916	$0.89101	$0.06630
33	Demand Cost per Peak Day Therms				$22.84	$22.79	$25.82	$11.38	$4.85
34	Customer Cost per Customer per Month				$15.86	$14.53	$120.82	$207.87	$1,503.79
	Cost by Classification at Uniform Proposed Return								
35	Commodity				67,525,892	50,280,920	16,702,918	375,731	166,324
36	Demand				13,321,397	10,198,409	3,031,659	23,091	68,238
37	Customer				13,659,316	12,349,045	1,224,765	2,435	83,070
38	Total Uniform Proposed Cost				94,506,605	72,828,375	20,959,341	401,257	317,632
	Cost per Therm at Proposed Return								
39	Commodity				$0.86457	$0.89533	$0.89162	$0.88861	$0.05966
40	Demand				$0.17056	$0.18160	$0.16183	$0.05461	$0.02448
41	Customer				$0.17489	$0.21989	$0.06538	$0.00576	$0.02980
42	Total Cost per Therm at Proposed Return				$1.21002	$1.29682	$1.11883	$0.94898	$0.11393
	Cost per Unit at Uniform Proposed Return								
43	Commodity Cost per Therm				$0.86457	$0.89533	$0.89162	$0.88861	$0.05966
44	Demand Cost per Peak Day Therms				$22.86	$22.74	$26.19	$11.01	$4.13
45	Customer Cost per Customer per Month				$15.85	$14.49	$123.33	$202.92	$1,384.51
46	**Revenue to Cost Ratio at Proposed Rates**				**1.00**	**1.00**	**0.99**	**1.00**	**1.12**
47	**Current Revenue to Proposed Cost Ratio**				**0.97**	**0.97**	**0.97**	**0.99**	**1.01**