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

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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-08-01 CASE NO. AVU-G-08-01 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 since 1999, which is a discussion group made up of technical professionals from 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 and the production property adjustment to the test year results of operations.

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

A. Yes. I am sponsoring Exhibit No. 14 composed of five schedules as follows: Schedule 1, production property adjustment calculation; Schedule 2, electric cost of service study process description; Schedule 3, electric cost of service study summary results; Schedule 4, natural gas cost of service study process description; and Schedule 5, 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 2007 test period and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment decreases Idaho net operating income by $632,000 as shown in column (u) on page 6 of Ms. Andrews Exhibit No.13, 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 calendar-year basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue.

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 2007 test period to the amount expected if weather had been normal. This adjustment incorporates the effect of both heating and cooling on weather-sensitive customer groups. The weather adjustment is developed from regression analysis of five or ten years (as explained later) of billed usage per customer and billing period heating and cooling degree-day data. The resulting seasonal weather sensitivity factors 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.

In addition to its use as a component of the revenue normalization adjustment, Company witness Mr. Kalich includes the combined Washington and Idaho adjustment with 2007 loads to reflect the normal load shape for 2009 pro forma loads in the modeling for the Pro Forma Power Supply costs.

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

A. Normal heating and cooling degree days are based on a rolling 25-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 25 years are included on a heating season basis, July through June, so (for example) the October average reflects all the Octobers beginning in 1982 and through 2006 whereas the May average reflects all of the Mays beginning in 1983 and through 2007. For cooling, the

25 years reflect the cooling season calendar years beginning in 1983 and through 2007. Each year the normal 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. What revisions have you made to the weather adjustment methodology since the company's last general rate case in Idaho?

A. In prior cases, annual average sensitivity factors were derived and applied uniformly to all heating and cooling degree days throughout the year. In this new process the definition of the independent variables has been adjusted to produce seasonal sensitivity factors. Seasonal sensitivity factors change depending on the time of year, therefore it is important to determine when the deviations from heating and cooling degree days occurred, which is why we now use a monthly calculation to determine the adjustment volumes. This modification addressed concerns that applying the annual factors on a monthly basis produced some counter-intuitive results during shoulder and summer months, as well as concerns (particularly for natural gas) that the baseload value should approximate observed summer usage.

Also, we re-examined the question of whether five years of data included enough data points. Based on trend variables testing for systematic changes over time, we were comfortable with the use of ten year data sets for electric residential customers and all weather-sensitive natural gas customer groups in Idaho (as well as all electric and natural gas weather-sensitive customer groups in Washington). However, in response to visual inspection of graphed residuals (error values) over time, a marked change appeared to occur in Idaho electric general service customer groups about halfway through the ten year period. Consequently, the Idaho residential customer group utilizes a ten year regression analysis whereas the weather-sensitive general service customer groups utilize a five year regression analysis.

Finally, in the methodology utilized in prior cases, two statistical tests were used to determine whether a regression result was acceptable. Namely, the t-statistic for all independent variables must be greater than the absolute value of two, and the adjusted R-square statistic must be greater than sixty percent. For the new method we have added a third test to satisfy concerns that auto-correlation of error terms may have been present in the data. Now in addition to the first two tests, the regression result must also pass the Durbin-Watson test for auto-correlation at five percent significance.

Q. How has the definition of normal heating and cooling degree days changed?

A. In prior cases the Company has used NOAA (National Oceanographic and Atmospheric Administration) published Monthly Station Normals for the Spokane airport weather station which represents a 30-year average. As mentioned above, in this case the Company is proposing a 25-year average instead.

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

A. The NOAA normal publication utilizes the same National Weather Service data to develop their 30-year average or "normal", but it is only updated every ten years, so those statistics now reflect 1971 to 2000 data, which does not include the most current weather. During the years since the last NOAA publication, the Inland Northwest has experienced consistently warmer weather. Therefore, use of the outdated 30-year average may tend to overstate expected heating requirements and understate expected cooling requirements. Moving to a shorter average period, and maintaining the rolling average to keep current with the weather that has been experienced in Avista's service territory, helps to overcome the limitations of the published "normal" data.

Q. What was the impact of electric weather normalization on the 2007 test year?

A. Weather was warmer than normal during the 2007 test year, especially during the month of July, resulting in a net reduction to usage. The adjustment to normal required the addition of 77 heating degree-days and the deduction of 139 cooling degree-days. The net adjustment to Idaho sales volumes was a reduction of 14,411,360 kWhs which is slightly less than one-half of one percent of billed usage.

<u>Natural Gas Revenue Normalization</u>

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

A. Yes. The natural gas revenue normalization adjustment is similar to the electric adjustment and represents the difference between the Company's actual recorded retail revenues during the 2007 test period and retail revenues on a normalized (pro forma) basis. The adjustment includes the re-pricing of pro forma sales and transportation volumes at present rates using pro forma sales volumes that have been adjusted for unbilled sales, abnormal weather, and any material customer load or schedule changes. The rates used exclude: 1) Temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization rate for deferred gas costs approved in the Company's last PGA filing 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-07-02, the Company's 2007 PGA filing, as set forth under Schedule 150. Those gas costs are then applied to the pro forma retail sales volumes so that there is a matching of revenues and gas costs.

The total net amount of the natural gas revenue normalization, which includes the purchase gas cost adjustment, is a decrease to net operating income of $42,000, as shown in column (i), page 5 of Ms. Andrews Exhibit No.13, 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 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 and cooling degree days defined?

A. Normal heating degree-days are based on a rolling 25-year average of heating degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. The 25 years are included on a heating season basis, July through June, so (for example) the October average reflects all the Octobers beginning in 1982 and through 2006 whereas the May average reflects all of the Mays beginning in 1983 and through 2007. 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. Does this proposed weather adjustment methodology reflect the same revisions that were discussed regarding electric service?

A. Yes, both the revisions to the process for determining the weather sensitivity factors and the change to the definition of "normal" are reflected in the

Company's weather normalization adjustment to natural gas usage.

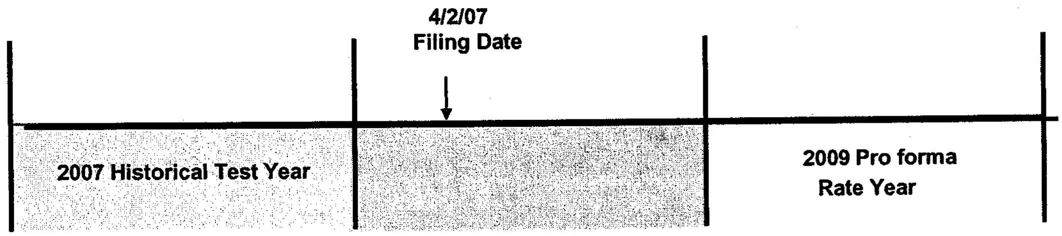
Q. What was the impact of natural gas weather normalization on the 2007 test year?

A. Weather was warmer than normal during the 2007 test year. A colder than normal January was offset by warmer than normal February, March, and December resulting in a relatively small annual weather adjustment. The adjustment to normal required the addition of 77 heating degree-days. The adjustment to sales volumes was an addition of 331,196 therms which is less than one-third of one percent of billed usage.

III. PRODUCTION PROPERTY ADJUSTMENT

Q. What is the purpose of a Production Property Adjustment?

A. The purpose of using a Production Property Adjustment is to avoid an over-collection of fixed and variable production costs resulting from an increase in retail load from the historical test period to the pro forma rate period. In this general rate case Avista is using a 2007 historical test period, and a 2009 pro forma rate year. The illustration below shows, for Avista's present case: 1) the 2007 historical test year, 2) the date of the current rate case filing, and 3) the pro forma rate year (calendar year 2009) in which new rates, if approved, will be in place.



In a rate case, the revenue requirement is spread to historical test year loads to establish new retail rates, which for Avista's present rate case is 2007 retail loads. When a rate case is developed to include the fixed and variable power supply costs during the 2009 pro forma rate year to serve 2009 rate year loads, we need to ensure that those fixed and variable costs are not over-collected as the load grows from the 2007 test year to the 2009 pro forma rate year. The Production Property Adjustment serves this purpose. The use of a Production Property Adjustment was approved by the Washington Utilities and Transportation Commission in the Company's recently-concluded 2007 rate case.

Q. Why is Avista proposing a Production Property Adjustment in this case?

A. We believe a Production Property Adjustment, in conjunction with pro forma rate year loads for power supply, results in a better matching of revenues and expenses during the period that new retail rates from this rate case will be in effect. The use of 2009 pro forma loads will result in pro forma revenues and expenses in this filing that are much closer to what is expected to occur during the 2009 rate year, and the Production Property Adjustment will ensure that the Company does not over-collect its fixed and variable production costs. The Retail Revenue Credit (incremental load) adjustments in the PCA would be relatively small, since any true-ups would be based on a comparison of actual load for 2009 versus the 2009 pro forma load included in base rates.

We have also applied the same theory to transmission fixed and variable costs in the development of the Production Property Adjustment. As loads grow, new customers (new retail KWH sales) will contribute toward the recovery of these transmission costs, and we have applied the same adjustment to transmission costs. Therefore, the proposed Production Property Adjustment ensures that both production costs and transmission costs are not over-collected during the year that rates go into effect.

Q. How is the Production Property Adjustment applied?

A. The production and transmission costs, both fixed and variable, that are included in the proposed retail rates in this case are factored down by the ratio of the Idaho 2007 test period loads and the Idaho 2009 pro forma rate year loads. The retail load associated with the directly assigned purchase of Potlatch generation (which is tracked through the PCA at 100%) has been excluded from both 2007 and 2009 in order to match the proposed authorized retail load used to determine incremental load adjustments in the PCA. This ratio is then applied to the Production and Transmission operating and maintenance expenses, including depreciation and amortization expense, as well as net Production and Transmission rate base.

Company witness Mr. Kalich included the 2009 pro forma rate year loads in the AURORA model so that the costs associated with serving the loads are reflected in this case, and he provides further explanation of these loads in his testimony.

Q. Do you have an exhibit that shows the calculation of the production property adjustment?

A. Yes. Exhibit No. 14, 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 2007 results of operations (not including the production property adjustment). The values on line 39, labeled <u>Pro Forma Total,</u> reflect production and transmission revenues, expenses, and rate base necessary to serve 2009 retail loads. The values on line 43, labeled <u>2007</u>

Production/Transmission Costs, are the amounts on line 39 multiplied by the production factor (calculated on line 42) in order to reflect the proportion of those costs required to be recovered by 2007 retail loads. The difference between the 2007 and 2009 values (shown on line 44), is the production property adjustment Ms. Andrews included in her calculation of revenue requirement in this case.

Q. What is shown on page 2 of Exhibit 14, Schedule 1?

A. Page 2 of Exhibit No.14, Schedule 1 shows the calculation of the proposed revenue requirement associated with production and transmission costs in this case. The rate of return and debt cost percentages on line 2 are inputs from the proposed cost of capital. The rate base and net expense values are the same costs calculated on page 1 to determine the production property adjustment. The value of the Potlatch Generation purchase has been excluded from net expense consistent with the exclusion of the related load for PCA purposes. Line 10 shows the average Production and Transmission cost per kWh proposed to be embedded in customer 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. 14, 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.14, Schedule 2 is based on the 2007 test year pro forma results of operations presented by Company witness Ms. Andrews in Exhibit No.13, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 14, Schedule 3?

A. Yes. Exhibit No. 14, 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.

Q. Given that the specific details of this methodology are described in Exhibit No. 14, Schedule 2, would you please give a brief overview of the key elements and the history associated with those elements?

A. 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[1] accepted by the Idaho commission in Case No. WWP-E-98-11. Additional direct assignment of demand related distribution plant has been incorporated to reflect improvements accepted by the commission in Case No. AVU-E-04-01. Administrative and general costs are first directly assigned to production, transmission, distribution, or customer relations functions. The remaining administrative and general costs are categorized as common costs and have been assigned to customer classes by the four-factor allocator accepted by the Idaho commission in Case No. AVU-E-04-01.

Q. 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:

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

Table 1

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	4.35%	0.87
General Service Schedule 11	7.49%	1.51
Large General Service Schedule 21	6.02%	1.21
Extra Large General Service Schedule 25	2.88%	0.58
Ex. Lg. Gen. Service Potlatch Schedule 25P	3.71%	0.75
Pumping Service Schedule 31	6.71%	1.35
Lighting Service Schedules 41 - 49	4.48%	0.90
Total Idaho Electric System	4.97%	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.

Q Does the Company have recent load research study information to use in the determination of demand-related allocations?

A. No. The load shape estimates included the calculation of the demand allocation factors for this cost of service study were derived from load research performed in the early 1980's and statistically updated in 1993. The estimation process used to develop the demand allocation factors for most customer groups (rate schedules) utilizes current billing system statistics and predicted daily volumes from the current weather sensitivity analysis in conjunction with load shape relationships produced by the prior load research data. The extra large general service schedules are not estimated, as current actual hourly demand data is available for them.

Q How does the load shape information affect the cost of service study results?

A. Slightly more than one-third of the costs in this study are demand-related and therefore affected by the coincident peak or non-coincident peak allocation factors. Even though I believe the study as a whole provides a reasonable representation of the cost of service, the results should not be used with a high level of precision.

In addition, because of the absence of a recent demand study, reliable data was not available to conduct adequate analysis of demand-metered Schedule 11 customers to evaluate the reasonableness of segregating them into a separate schedule, as briefly addressed in Mr. Hirschkorn's testimony.

Q. Is the Company conducting a new demand study?

A. Yes. Currently the Company is in the process of developing an hourly load research study. Under the current timeline, load research meters will be installed on a statistical sample of customers from each of the customer groups later this year in order to collect a full year of hourly data.

V. 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.14, Schedule 4 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.14, Schedule 5 is based on the 2007 test year pro forma results of operations presented by Ms. Andrews in Exhibit No.13, Schedule 2.

Q. Would you please explain the cost of service study presented in Exhibit No. 14, Schedule 5?

A. Yes. Exhibit No. 14, Schedule 5 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.

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.14, Schedule 4.

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 and Interruptible Service schedules (121 and 131) are providing less than the overall return (unity), while Transportation Service Schedule 146 is providing more than unity. Small Firm is also above unity, but below the requested return, and Residential Service is only slightly below unity.

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

Table 2

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 101	4.93%	0.95
Small Firm Service Schedule 111	7.14%	1.37
Large Firm Service Schedule 121	2.40%	0.46
Interruptible Service Schedule 131	3.21%	0.62
Transportation Service Schedule 146	11.22%	2.15
Total Idaho Natural Gas System	5.21%	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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DAVID J. MEYER
VICE PRESIDENT, GENERAL COUNSEL, REGULATORY &
GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-08-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-08-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 14
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND GAS)

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CONFIDENTIAL

Avista Utilities
Production Property Adjustment Calculation
Idaho Electric
Twelve Months Ended December 31, 2007

THIS PAGE ALLEGEDLY CONTAINS TRADE SECRETS OR CONFIDENTIAL MATERIALS AND IS SEPARATELY FILED.

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

			2007	2009	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	$298,570	$313,996	
2		Proposed Rate of Return	8.740%	8.740%	3.56%
3	Rate Base	Net Operating Income Requirement	$26,095	$27,443	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,720)	($3,912)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	$95,600	100,539	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($33,460)	($35,189)	
7	Total Prod/Trans	Net Operating Income Requirement	$84,515	$88,881	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.	0.65	0.65	
9	Prod/Trans	Revenue Requirement	$130,023	$136,740	$6,718
10	Prod/Trans Rev Requirement per kWh		$ 0.04383	$ 0.04383	6,718
11	Potlatch Generation Purchase of $19,861 Passed through PCA at 100% Excluded from Net Expense on Line 5		18,885	19,861	976

ELECTRIC COST OF SERVICE

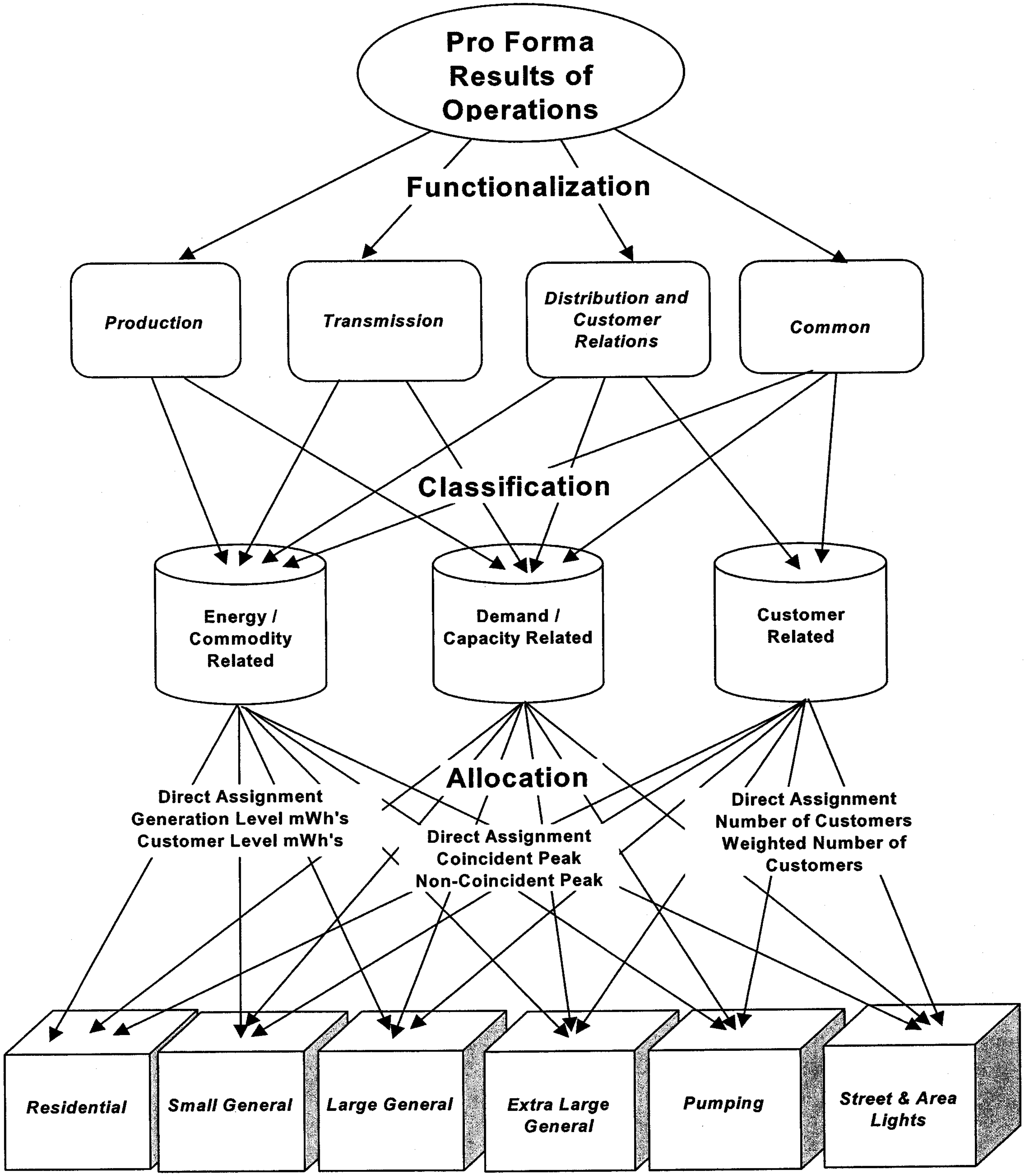
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study 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

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 33.57% to demand and 66.43% to energy. The peak credit ratio for hydro plant is 26.82% to demand and 73.18% 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 30.19% to demand and 69.81% 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-08-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Account	Functional Category	Classification	Allocation
Production Plant			
Thermal Production	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Hydro Production	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Other Production (Coyote Springs)	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Other Production	P = Production	Demand	D01 Coincident Peak Demand
Transmission Plant			
All Transmission	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Distribution Plant			
360 Land	D = Distribution	Demand	D02 Non-coincident Peak Demand (NCP)
361 Structures	D = Distribution	Demand	D03/D04/D05 Direct Assign Large / Non-coincident Peak Demand Excl DA
362 Station Equipment	D = Distribution	Demand	D03/D04/D05 Direct Assign Large / Non-coincident Peak Demand Excl DA
364 Poles Towers & Fixtures	D = Distribution	Demand	D03/C04/D06/D07 Direct Assign Large & Lights / NCP Excl DA / NCP Secondary
365 Overhead Conductors & Devices	D = Distribution	Demand	D03/C04/D06 Direct Assign Large / NCP Excl DA / NCP Secondary
366 Underground Conduit	D = Distribution	Demand	D03/C04/D06 Direct Assign Large / NCP Excl DA / NCP Secondary
367 Underground Conductors & Devices	D = Distribution	Demand	D03/C04/D06 Direct Assign Large / NCP Excl DA / NCP Secondary
368 Line Transformers	D = Distribution	Demand	D06 Non-coincident Peak Demand Secondary
369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
General Plant			
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			
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
302 Franchises & Consents	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
303 Misc Intangible Plant - Grant Co Transmission	T = Transmission	Demand/Energy by Trans Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
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			
Intangible	P/T/O	Follows Related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Transmission	T = Transmission	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Distribution	D = Distribution	Follows Related Plant	D02/D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
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			
252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
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
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
Hydro Related Deferred Balances	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Demand Side Management Investment	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
Production O&M			
Thermal	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
Thermal Fuel (501)	P = Production	Energy	E02 Annual Generation Level Consumption
Hydro	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption

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

IPUC Case No. AVU-E-08-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Account	Functional Category	Classification	Allocation	
Admin & General Expenses				
920 - 927 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01	Sum of Production Plant
920 - 927 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02	Sum of Transmission Plant
920 - 927 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03	Sum of Distribution Plant
920 - 927 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01	All Customers unweighted
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
928 FERC Commission Fees	P = Production	Energy	E02	Annual Generation Level Consumption
928 IPUC Commission Fees	R = Revenue Conversion	Revenue	R01	Retail Sales Revenue
Depreciation & Amortization Expense				
Intangible	P/T/O	Demand/Energy/Customer as in related Plant	S01/S02/S23	Sum of Production Plant / Sum of Transmission Plant / Corp Cost Alloctor
Production	P = Production	Demand/Energy as in related Plant	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
Transmission	T = Transmission	Demand/Energy as in related Plant	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
Distribution	D = Distribution	Demand/Customer as in related Plant	D02/D03/D04/D05/D06/D07/D08/C02/C04/C05	- See Related Plant
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				
Property Tax	P/T/D/O	Demand/Energy/Customer from Related Plant	S01/S02/S03/S04	Sums of Production / Transmission / Distribution / General Plant
State kWh Generation Taxes	P = Production	Demand/Energy by Combo Peak Credits & Energy	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
Misc Production Taxes	P = Production	Demand/Energy by Combo Peak Credits & Energy	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03	Sum of Distribution Plant
Idaho State Income Tax	R = Revenue Conversion	Revenue	R03	Revenue less Expenses Before Income Taxes less Interest Expense
Federal Income Tax	R = Revenue Conversion	Revenue	R03	Revenue less Expenses Before Income Taxes less Interest Expense
Deferred FIT	R = Revenue Conversion	Revenue	R03	Revenue less Expenses Before Income Taxes less Interest Expense
Other Income Related Items				
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				
Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input	Pro Forma Revenue per Revenue Study
Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01	Sum of Production Plant
Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03	Sum of Distribution Plant
Sales of Water & Water Power (453)	P = Production	Demand	D01	Coincident Peak Demand
Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01	Sum of Production Plant
Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03	Sum of Distribution Plant
Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01	Sum of Production Plant
Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02	Sum of Transmission Plant
Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03	Sum of Distribution Plant
Optional Renewable Revenue (Sch 95)	P = Production	Demand/Energy from Production Plant	S01	Sum of Production Plant
Montana Retail Revenue	P = Production	Demand	D01	Coincident Peak Demand
Salaries & Wages (allocation factor input)				
Operation & Maintenance Expenses				
Production Total	P = Production	Demand/Energy from Production Plant	S01	Sum of Production Plant
Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02	Sum of Transmission Plant
Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03	Sum of Distribution Plant
Customer Accounts Total	C = Customer Relations	Customer	S18	Sum of Other Customer Accounts Expenses Excluding Uncollectibles
Customer Service Total	C = Customer Relations	Customer	C01	All Customers unweighted
Sales Total	C = Customer Relations	Energy	E02	Annual Generation Level Consumption
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 Year Ended December 31, 2007

Idaho Jurisdiction
Electric Utility

03-18-08

	(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				349,419,000	123,948,683	35,008,568	70,179,596	30,627,751	82,600,694	5,905,485	1,148,222
2	Transmission Plant				153,519,000	53,811,223	15,204,909	30,833,976	13,554,024	36,979,568	2,608,315	526,984
3	Distribution Plant				365,131,000	183,065,950	58,338,616	83,921,796	11,469,208	2,105,462	8,085,480	18,144,488
4	Intangible Plant				23,770,000	9,447,400	2,548,292	4,458,737	1,844,839	4,897,055	398,384	175,291
5	General Plant				55,533,000	29,356,229	7,246,227	8,430,323	2,672,657	5,946,234	890,769	990,562
6	Total Plant In Service				947,372,000	399,629,485	118,346,611	197,824,428	60,168,480	132,529,014	17,888,433	20,985,548
	Accum Depreciation											
7	Production Plant				(134,749,000)	(47,635,747)	(13,456,014)	(27,063,925)	(11,835,886)	(32,028,093)	(2,280,844)	(448,491)
8	Transmission Plant				(51,662,000)	(18,108,478)	(5,116,735)	(10,376,207)	(4,561,181)	(12,444,313)	(877,747)	(177,340)
9	Distribution Plant				(111,662,000)	(55,324,436)	(16,812,884)	(25,432,107)	(3,115,642)	(574,733)	(2,316,497)	(8,085,701)
10	Intangible Plant				(4,540,000)	(2,198,979)	(556,724)	(743,985)	(263,667)	(637,755)	(73,927)	(64,963)
11	General Plant				(24,058,000)	(12,717,702)	(3,139,210)	(3,652,183)	(1,157,848)	(2,576,027)	(385,899)	(429,131)
12	Total Accumulated Depreciation				(326,671,000)	(135,985,342)	(39,081,567)	(67,268,407)	(20,934,224)	(48,260,921)	(5,934,914)	(9,205,626)
13	Net Plant				620,701,000	263,644,143	79,265,044	130,556,021	39,234,257	84,268,094	11,953,519	11,779,923
14	Accumulated Deferred FIT				(88,531,000)	(37,017,203)	(10,836,262)	(18,236,718)	(5,810,553)	(13,221,784)	(1,643,787)	(1,764,693)
15	Miscellaneous Rate Base				16,096,000	5,212,821	1,535,993	3,392,291	1,503,131	4,118,703	278,963	54,097
16	Total Rate Base				548,266,000	231,839,762	69,964,775	115,711,593	34,926,835	75,165,013	10,588,696	10,069,327
17	Revenue From Retail Rates				193,270,000	75,282,000	24,573,000	40,085,000	13,077,000	34,045,000	3,690,000	2,518,000
18	Other Operating Revenues				31,389,000	11,319,081	3,221,092	6,342,676	2,678,443	7,125,315	537,623	164,771
19	Total Revenues				224,659,000	86,601,081	27,794,092	46,427,676	15,755,443	41,170,315	4,227,623	2,682,771
	Operating Expenses											
20	Production Expenses				118,970,000	41,385,697	11,697,037	23,894,986	10,551,358	28,993,533	2,028,014	419,375
21	Transmission Expenses				8,348,000	2,926,127	826,807	1,676,679	737,036	2,010,861	141,834	28,656
22	Distribution Expenses				8,537,000	4,069,514	1,138,788	2,003,212	348,837	70,502	156,467	749,679
23	Customer Accounting Expenses				3,291,000	2,465,581	547,061	127,538	28,470	72,962	41,367	8,021
24	Customer Information Expenses				1,518,000	649,075	165,574	259,923	112,222	302,587	24,160	4,459
25	Sales Expenses				276,000	92,283	26,119	55,436	25,041	71,235	4,784	1,103
26	Admin & General Expenses				20,109,000	10,345,438	2,612,430	3,195,884	1,006,053	2,252,631	330,565	365,998
27	Total O&M Expenses				161,049,000	61,933,715	17,013,815	31,213,658	12,809,018	33,774,312	2,727,191	1,577,291
28	Taxes Other Than Income Taxes				6,413,000	2,544,288	749,790	1,335,626	458,229	1,099,714	118,113	107,239
29	Other Income Related Items				(158,000)	(59,188)	(16,687)	(31,733)	(13,375)	(34,004)	(2,604)	(410)
	Depreciation Expense											
30	Production Plant Depreciation				9,073,000	3,237,319	914,179	1,822,274	792,430	2,124,699	152,941	29,157
31	Transmission Plant Depreciation				3,112,000	1,090,813	308,220	625,039	274,755	749,617	52,873	10,683
32	Distribution Plant Depreciation				9,159,000	4,502,933	1,488,388	2,199,909	320,557	50,232	210,580	386,400
33	General Plant Depreciation				3,842,000	2,030,984	501,324	583,244	184,905	411,385	61,627	68,531
34	Amortization Expense				637,000	229,264	64,722	127,938	55,337	147,064	10,696	1,978
35	Total Depreciation Expense				25,823,000	11,091,314	3,276,834	5,358,404	1,627,984	3,482,997	488,718	496,750
36	Income Tax				4,290,000	1,013,249	1,528,184	1,582,752	(132,046)	61,225	185,417	51,219
37	Total Operating Expenses				197,417,000	76,523,379	22,551,936	39,458,708	14,749,810	38,384,244	3,516,834	2,232,089
38	Net Income				27,242,000	10,077,702	5,242,156	6,968,968	1,005,633	2,786,071	710,789	450,682
39	Rate of Return				4.97%	4.35%	7.49%	6.02%	2.88%	3.71%	6.71%	4.48%
40	Return Ratio				1.00	0.87	1.51	1.21	0.58	0.75	1.35	0.90
41	Interest Expense				19,518,000	8,253,382	2,490,712	4,119,276	1,243,378	2,675,837	376,952	358,463

Sumcost
Scenario: Company Base Case
AVU-E-04-01 Method
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AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Year Ended December 31, 2007

Idaho Jurisdiction
Electric Utility

03-18-08

	(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
	Functional Cost Components at Current Return by Schedule								
1	Production	117,314,335	40,313,386	12,416,443	24,385,897	9,873,346	27,806,569	2,107,399	411,296
2	Transmission	15,109,239	5,099,767	1,871,804	3,387,609	1,105,369	3,291,359	302,776	50,555
3	Distribution	38,245,594	18,043,943	7,197,848	8,811,528	1,050,641	579,955	905,478	1,656,202
4	Common	22,600,832	11,824,903	3,086,906	3,499,967	1,047,645	2,367,116	374,347	399,948
5	Total Current Rate Revenue	193,270,000	75,282,000	24,573,000	40,085,000	13,077,000	34,045,000	3,690,000	2,518,000
	Expressed as $/kWh								
6	Production	$0.03421	$0.03546	$0.03859	$0.03563	$0.03128	$0.03096	$0.03576	$0.03028
7	Transmission	$0.00441	$0.00449	$0.00582	$0.00495	$0.00350	$0.00366	$0.00514	$0.00372
8	Distribution	$0.01115	$0.01587	$0.02237	$0.01288	$0.00333	$0.00065	$0.01537	$0.12193
9	Common	$0.00659	$0.01040	$0.00959	$0.00511	$0.00332	$0.00264	$0.00635	$0.02944
10	Total Current Melded Rates	$0.05636	$0.06623	$0.07638	$0.05858	$0.04143	$0.03790	$0.06262	$0.18537
	Functional Cost Components at Uniform Current Return								
11	Production	117,995,190	41,028,867	11,596,359	23,699,203	10,467,579	28,774,853	2,011,773	416,556
12	Transmission	15,409,177	5,401,199	1,526,164	3,094,902	1,360,459	3,711,754	261,805	52,895
13	Distribution	37,241,883	19,145,624	5,738,999	7,950,640	1,300,608	618,486	764,953	1,722,572
14	Common	22,623,750	11,959,519	2,952,061	3,434,454	1,088,821	2,422,454	362,893	403,548
15	Total Uniform Current Cost	193,270,000	77,535,210	21,813,583	38,179,198	14,217,468	35,527,546	3,401,424	2,595,571
	Expressed as $/kWh								
16	Production	$0.03441	$0.03609	$0.03604	$0.03463	$0.03316	$0.03203	$0.03414	$0.03067
17	Transmission	$0.00449	$0.00475	$0.00474	$0.00452	$0.00431	$0.00413	$0.00444	$0.00389
18	Distribution	$0.01086	$0.01684	$0.01784	$0.01162	$0.00412	$0.00069	$0.01298	$0.12681
19	Common	$0.00660	$0.01052	$0.00918	$0.00502	$0.00345	$0.00270	$0.00616	$0.02971
20	Total Current Uniform Melded Rates	$0.05636	$0.06821	$0.06780	$0.05579	$0.04504	$0.03955	$0.05772	$0.19108
21	**Revenue to Cost Ratio at Current Rates**	1.00	0.97	1.13	1.05	0.92	0.96	1.08	0.97
	Functional Cost Components at Proposed Return by Schedule								
22	Production	130,110,384	44,338,438	13,646,603	26,818,145	11,018,412	31,535,243	2,313,306	440,238
23	Transmission	20,514,455	6,776,019	2,384,762	4,412,867	1,591,776	4,895,805	390,013	63,213
24	Distribution	50,830,925	24,169,376	9,361,742	11,825,050	1,527,225	727,466	1,204,470	2,015,596
25	Common	24,142,236	12,589,166	3,290,894	3,733,938	1,127,587	2,581,486	399,211	419,953
26	Total Proposed Rate Revenue	225,598,000	87,873,000	28,684,000	46,790,000	15,265,000	39,740,000	4,307,000	2,939,000
	Expressed as $/kWh								
27	Production	$0.03794	$0.03901	$0.04242	$0.03919	$0.03491	$0.03511	$0.03926	$0.03241
28	Transmission	$0.00598	$0.00596	$0.00741	$0.00645	$0.00504	$0.00545	$0.00662	$0.00465
29	Distribution	$0.01482	$0.02126	$0.02910	$0.01728	$0.00484	$0.00081	$0.02044	$0.14839
30	Common	$0.00704	$0.01108	$0.01023	$0.00546	$0.00357	$0.00287	$0.00677	$0.03092
31	Total Proposed Melded Rates	$0.06579	$0.07730	$0.08916	$0.06837	$0.04836	$0.04424	$0.07309	$0.21637
	Functional Cost Components at Uniform Requested Return								
32	Production	130,308,838	45,394,422	12,829,408	26,172,357	11,547,280	31,688,330	2,219,937	457,104
33	Transmission	20,600,662	7,220,909	2,040,341	4,137,601	1,818,810	4,962,276	350,009	70,716
34	Distribution	50,497,809	25,795,375	7,908,043	11,015,458	1,749,698	733,558	1,067,261	2,228,416
35	Common	24,190,691	12,787,846	3,156,524	3,672,327	1,164,234	2,590,235	388,027	431,498
36	Total Uniform Cost	225,598,000	91,198,552	25,934,316	44,997,742	16,280,022	39,974,399	4,025,234	3,187,735
	Expressed as $/kWh								
37	Production	$0.03800	$0.03993	$0.03988	$0.03825	$0.03658	$0.03528	$0.03767	$0.03365
38	Transmission	$0.00601	$0.00635	$0.00634	$0.00605	$0.00576	$0.00552	$0.00594	$0.00521
39	Distribution	$0.01473	$0.02269	$0.02458	$0.01610	$0.00554	$0.00082	$0.01811	$0.16405
40	Common	$0.00705	$0.01125	$0.00981	$0.00537	$0.00369	$0.00288	$0.00658	$0.03177
41	Total Uniform Melded Rates	$0.06579	$0.08023	$0.08061	$0.06575	$0.05158	$0.04450	$0.06831	$0.23468
42	**Revenue to Cost Ratio at Proposed Rates**	1.00	0.96	1.11	1.04	0.94	0.99	1.07	0.92
43	**Current Revenue to Proposed Cost Ratio**	**0.86**	**0.83**	**0.95**	**0.89**	**0.80**	**0.85**	**0.92**	**0.79**

Sumcost
Scenario: Company Base Case
AVU-E-04-01 Method
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AVISTA UTILITIES
Revenue to Cost By Classification Summary
For the Year Ended December 31, 2007

Idaho Jurisdiction
Electric Utility

03-18-08

	(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		106,334,253	35,159,428	10,881,403	22,172,428	9,124,553	26,623,905	1,950,780	421,757
2	Demand		69,137,127	27,848,290	10,237,132	17,427,091	3,946,973	7,420,441	1,449,996	807,205
3	Customer		17,798,620	12,274,282	3,454,465	485,481	5,474	654	289,224	1,289,038
4	Total Current Rate Revenue		193,270,000	75,282,000	24,573,000	40,085,000	13,077,000	34,045,000	3,690,000	2,518,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.03101	$0.03093	$0.03382	$0.03240	$0.02891	$0.02964	$0.03311	$0.03105
6	Demand	$/kW/mo	$8.69	$9.23	$10.68	$9.52	$6.62	$5.41	$10.18	$19.69
7	Customer	$/Cust/mo	$12.54	$10.55	$15.51	$28.66	$35.09	$54.53	$19.19	$854.23
	Cost Classifications at Uniform Current Return									
8	Energy		107,098,144	35,809,128	10,135,170	21,511,023	9,716,872	27,641,706	1,856,335	427,911
9	Demand		68,533,320	29,083,623	8,705,851	16,232,748	4,492,959	7,885,043	1,292,795	840,300
10	Customer		17,638,536	12,642,458	2,972,562	435,427	7,637	798	252,295	1,327,360
11	Total Uniform Current Cost		193,270,000	77,535,210	21,813,583	38,179,198	14,217,468	35,527,546	3,401,424	2,595,571
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.03123	$0.03150	$0.03150	$0.03143	$0.03079	$0.03077	$0.03150	$0.03150
13	Demand	$/kW/mo	$8.61	$9.64	$9.09	$8.87	$7.53	$5.75	$9.07	$20.50
14	Customer	$/Cust/mo	$12.42	$10.87	$13.35	$25.70	$48.95	$66.48	$16.74	$879.63
15	**Revenue to Cost Ratio at Current Rates**		1.00	0.97	1.13	1.05	0.92	0.96	1.08	0.97
	Cost Classifications at Proposed Return by Schedule									
16	Energy		118,738,279	38,812,046	12,000,099	24,512,943	10,264,753	30,538,985	2,153,931	455,521
17	Demand		85,820,646	34,729,336	12,512,866	21,616,404	4,990,656	9,199,815	1,785,187	986,383
18	Customer		21,039,076	14,331,618	4,171,035	660,653	9,591	1,201	367,883	1,497,096
19	Total Proposed Rate Revenue		225,598,000	87,873,000	28,684,000	46,790,000	15,265,000	39,740,000	4,307,000	2,939,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.03463	$0.03414	$0.03730	$0.03582	$0.03252	$0.03400	$0.03655	$0.03353
21	Demand	$/kW/mo	$10.79	$11.51	$13.06	$11.81	$8.37	$6.71	$12.53	$24.06
22	Customer	$/Cust/mo	$14.82	$12.32	$18.73	$38.99	$61.48	$100.06	$24.41	$992.11
	Cost Classifications at Uniform Requested Return									
23	Energy		118,947,168	39,770,945	11,256,495	23,890,939	10,791,918	30,699,903	2,061,714	475,254
24	Demand		85,506,864	36,552,591	10,986,989	20,493,223	5,476,588	9,273,273	1,631,695	1,092,504
25	Customer		21,143,968	14,875,016	3,690,832	613,581	11,516	1,223	331,825	1,619,976
26	Total Uniform Cost		225,598,000	91,198,552	25,934,316	44,997,742	16,280,022	39,974,399	4,025,234	3,187,735
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.03469	$0.03499	$0.03499	$0.03491	$0.03419	$0.03418	$0.03499	$0.03499
28	Demand	$/kW/mo	$10.75	$12.11	$11.47	$11.19	$9.18	$6.77	$11.45	$26.65
29	Customer	$/Cust/mo	$14.89	$12.79	$16.57	$36.22	$73.82	$101.94	$22.02	$1,073.54
30	**Revenue to Cost Ratio at Proposed Rates**		1.00	0.96	1.11	1.04	0.94	0.99	1.07	0.92
31	**Current Revenue to Proposed Cost Ratio**		**0.86**	**0.83**	**0.95**	**0.89**	**0.80**	**0.85**	**0.92**	**0.79**

NATURAL GAS COST OF SERVICE STUDY

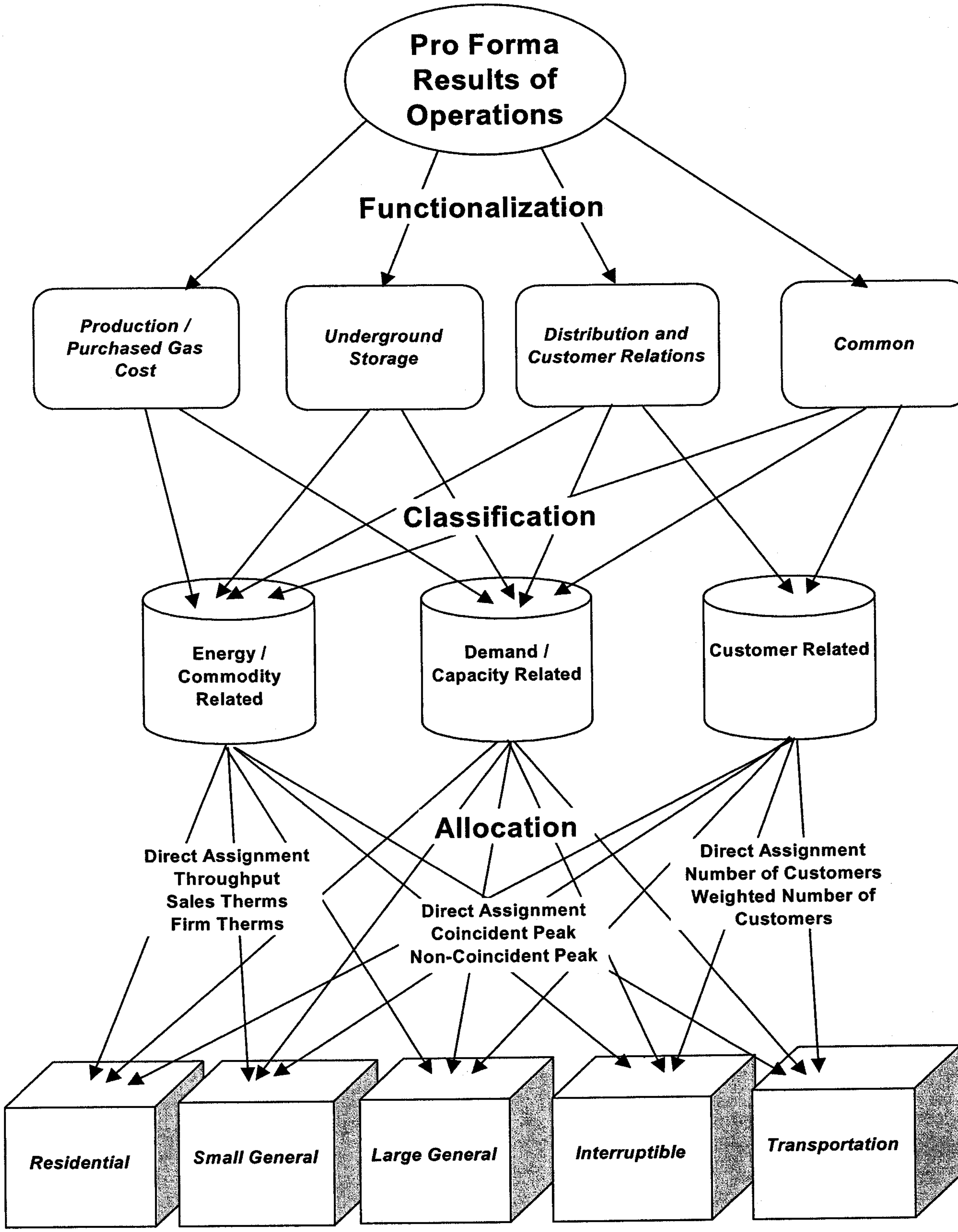
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study 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

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 November 1, 2007. 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 38%. This proportion is classified as commodity related. The remaining 62% 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 121, 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 customers excluding the small usage customer groups (Schedules101 and 111).

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-08-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

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

IPUC Case No. AVU-G-08-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

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

IPUC Case No. AVU-G-08-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Account	Functional Category	Classification	Allocation
Admin & General Expenses			
920 Salaries	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
921 Office Supplies	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
923 Outside Services	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
924 Property Insurance	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
925 Injuries & Damages	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
926 Pensions & Benefits	Common	Demand/Commodity/Customer from Labpr O&M	S13 O&M Labor Expense
927 Franchise Requirements	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
928 Regulatory Commision	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
928 Commission Fees	Revenue Conversion	Revenue	R01 Retail Sales Revenue
930 Miscellaneous General	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
931 Rents	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
935 MT of General Plant	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
Depreciation Expense			
Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
Taxes			
Property Tax	All	Demand/Commodity/Customer from related plant	S14/S15/S16 Sum of UG Plant/Sum of Dist Plant/Sum of Gen Plant
Miscellaneous Dist Tax	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
State Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
Federal Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
Deferred FIT	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
ITC	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
Operating Revenues			
Revenue from Rates	Revenue	Revenue	Pro Forma Revenue per Revenue Study
Special Contract Revenue	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
Off System Sales	Production	Commodity from PGA Tracker	E04 Sales Therms
Miscellaneous Service Revenue	Customer Relations	Customer	C01 All customers (unweighted)
Rent From Gas Property	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
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 December 31, 2007

Natural Gas Utility
Idaho Jurisdiction

24-Mar-08

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Plant In Service									
1	Production Plant									
2	Underground Storage Plant				8,709,000	6,588,047	1,677,480	143,935	34,633	264,905
3	Distribution Plant				121,478,000	102,470,164	16,129,186	1,414,545	338,017	1,126,088
4	Intangible Plant				1,281,000	1,074,031	174,572	15,283	3,654	13,461
5	General Plant				10,990,000	9,206,370	1,503,186	131,562	31,458	117,424
6	Total Plant In Service				142,458,000	119,338,613	19,484,424	1,705,325	407,762	1,521,877
	Accum Depreciation									
7	Production Plant									
8	Underground Storage Plant				(3,066,000)	(2,319,319)	(590,556)	(50,672)	(12,192)	(93,260)
9	Distribution Plant				(41,788,000)	(35,326,980)	(5,416,809)	(514,266)	(128,603)	(401,342)
10	Intangible Plant				(445,000)	(372,907)	(60,778)	(5,320)	(1,272)	(4,724)
11	General Plant				(3,644,000)	(3,052,595)	(498,418)	(43,623)	(10,431)	(38,935)
12	Total Accumulated Depreciation				(48,943,000)	(41,071,800)	(6,566,561)	(613,880)	(152,498)	(538,260)
13	Net Plant				93,515,000	78,266,813	12,917,862	1,091,444	255,263	983,617
14	Accumlulated Deferred FIT				(14,155,000)	(11,857,797)	(1,936,023)	(169,446)	(40,516)	(151,218)
15	Miscellaneous Rate Base				6,330,000	4,759,473	1,237,389	108,280	25,729	199,129
16	Total Rate Base				85,690,000	71,168,489	12,219,228	1,030,278	240,476	1,031,529
17	Revenue From Retail Rates				81,860,000	63,207,000	15,950,000	1,919,000	367,000	417,000
18	Other Operating Revenues				252,000	209,451	35,817	3,025	707	3,000
19	Total Revenues				82,112,000	63,416,451	15,985,817	1,922,025	367,707	420,000
	Operating Expenses									
20	Purchased Gas Costs				61,321,000	46,178,952	13,140,727	1,676,123	320,330	4,868
21	Underground Storage Expenses				174,000	131,625	33,515	2,876	692	5,293
22	Distribution Expenses				3,535,000	2,938,902	445,279	82,368	12,436	56,015
23	Customer Accounting Expenses				1,770,000	1,710,934	52,761	4,446	830	1,030
24	Customer Information Expenses				232,000	205,050	20,476	2,256	447	3,771
25	Sales Expenses				212,000	209,593	2,359	30	3	15
26	Admin & General Expenses				4,440,000	3,549,883	669,330	88,156	17,327	115,304
27	Total O&M Expenses				71,684,000	54,924,938	14,364,447	1,856,255	352,065	186,295
28	Taxes Other Than Income Taxes				702,000	584,294	98,612	8,615	2,061	8,417
29	Depreciation Expense									
30	Underground Storage Plant Depr				152,000	114,983	29,277	2,512	604	4,623
31	Distribution Plant Depreciation				2,618,000	2,250,371	308,465	31,864	5,173	22,128
32	General Plant Depreciation				683,000	572,152	93,419	8,176	1,955	7,298
33	Amortization of Intangible Plant				234,000	196,046	31,990	2,800	669	2,495
34	Total Depr & Amort Expense				3,687,000	3,133,551	463,151	45,352	8,402	36,543
35	Income Tax				1,572,000	1,178,319	328,573	(13,089)	(1,780)	79,977
36	Total Operating Expenses				77,645,000	59,821,103	15,254,783	1,897,133	360,748	311,233
37	Net Income				4,467,000	3,595,347	731,033	24,893	6,959	108,768
38	Rate of Return				5.21%	5.05%	5.98%	2.42%	2.89%	10.54%
39	Return Ratio				1.00	0.97	1.15	0.46	0.56	2.02
40	Interest Expense				3,051,000	2,636,146	336,763	37,765	6,307	34,020

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

AVISTA UTILITIES
Summary by Function with Margin Analysis
For the Year Ended December 31, 2007

Natural Gas Utility
Idaho Jurisdiction

24-Mar-08

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Functional Cost Components at Current Rates									
1	Production				61,613,790	46,399,443	13,203,470	1,684,126	321,859	4,891
2	Underground Storage				1,189,584	848,332	257,529	8,445	2,472	72,805
3	Distribution				13,397,259	11,392,635	1,649,516	130,672	23,111	201,325
4	Common				5,659,368	4,566,590	839,485	95,757	19,558	137,979
5	**Total Current Rate Revenue**				**81,860,000**	**63,207,000**	**15,950,000**	**1,919,000**	**367,000**	**417,000**
6	Exclude Cost of Gas w / Revenue Exp.				61,210,875	46,099,857	13,118,219	1,673,252	319,547	0
7	**Total Margin Revenue at Current Rates**				**20,649,125**	**17,107,143**	**2,831,781**	**245,748**	**47,453**	**417,000**
	Margin per Therm at Current Rates									
8	Production				$0.005292	$0.005494	$0.005494	$0.005494	$0.005494	$0.001326
9	Underground Storage				$0.015624	$0.015556	$0.016596	$0.004267	$0.005872	$0.019741
10	Distribution				$0.175957	$0.208912	$0.106297	$0.066018	$0.054897	$0.054590
11	Common				$0.074329	$0.083740	$0.054098	$0.048378	$0.046457	$0.037413
12	Total Current Margin Melded Rate per Therm				**$0.271202**	**$0.313702**	**$0.182484**	**$0.124156**	**$0.112720**	**$0.113071**
	Functional Cost Components at Uniform Current Return									
13	Production				61,613,790	46,399,443	13,203,470	1,684,126	321,859	4,891
14	Underground Storage				1,158,755	876,557	223,193	19,151	4,608	35,246
15	Distribution				13,426,260	11,588,246	1,499,465	176,286	31,853	130,410
16	Common				5,661,195	4,585,839	824,467	100,533	20,505	129,851
17	Total Uniform Current Cost				**81,860,000**	**63,450,086**	**15,750,595**	**1,980,096**	**378,825**	**300,399**
18	Exclude Cost of Gas w / Revenue Exp.				61,210,875	46,099,857	13,118,219	1,673,252	319,547	0
19	Total Uniform Current Margin				**20,649,125**	**17,350,229**	**2,632,376**	**306,843**	**59,278**	**300,399**
	Margin per Therm at Uniform Current Return									
20	Production				$0.005292	$0.005494	$0.005494	$0.005494	$0.005494	$0.001326
21	Underground Storage				$0.015219	$0.016074	$0.014383	$0.009675	$0.010946	$0.009557
22	Distribution				$0.176338	$0.212499	$0.096627	$0.089063	$0.075663	$0.035361
23	Common				$0.074353	$0.084093	$0.053130	$0.050791	$0.048706	$0.035209
24	Total Current Uniform Margin Melded Rate p				**$0.271202**	**$0.318159**	**$0.169634**	**$0.155022**	**$0.140808**	**$0.081454**
25	**Margin to Cost Ratio at Current Rates**				**1.00**	**0.99**	**1.08**	**0.80**	**0.80**	**1.39**
	Functional Cost Components at Proposed Rates									
26	Production				61,613,466	46,399,199	14,887,518	0	321,858	4,891
27	Underground Storage				1,773,719	1,325,735	368,328	0	5,681	73,974
28	Distribution				17,166,253	14,701,257	2,225,219	0	36,246	203,532
29	Common				6,031,563	4,892,166	980,186	0	20,980	138,231
30	**Total Proposed Rate Revenue**				**86,585,000**	**67,318,357**	**18,461,250**	**0**	**384,765**	**420,628**
31	Exclude Cost of Gas w / Revenue Exp.				61,210,553	46,099,614	14,791,394	0	319,545	0
32	**Total Margin Revenue at Proposed Rates**				**25,374,447**	**21,218,742**	**3,669,857**	**0**	**65,220**	**420,628**
	Margin per Therm at Proposed Rates									
33	Production				$0.005292	$0.005494	$0.005494	$0.000000	$0.005494	$0.001326
34	Underground Storage				$0.023296	$0.024311	$0.021051	$0.000000	$0.013495	$0.020058
35	Distribution				$0.225458	$0.269584	$0.127175	$0.000000	$0.086097	$0.055188
36	Common				$0.079217	$0.089710	$0.056019	$0.000000	$0.049837	$0.037482
37	Total Proposed Margin Melded Rate per Th				**$0.333263**	**$0.389098**	**$0.209738**	**$0.000000**	**$0.154922**	**$0.114054**
	Functional Cost Components at Uniform Proposed Return									
38	Production				61,613,466	46,399,199	14,887,518	0	321,858	4,891
39	Underground Storage				1,761,141	1,332,240	368,328	0	7,003	53,569
40	Distribution				17,178,223	14,746,343	2,225,219	0	41,656	165,005
41	Common				6,032,170	4,896,602	980,186	0	21,567	133,815
42	Total Uniform Proposed Cost				**86,585,000**	**67,374,384**	**18,461,250**	**0**	**392,084**	**357,281**
43	Exclude Cost of Gas w / Revenue Exp.				61,210,553	46,099,614	14,791,394	0	319,545	0
44	Total Uniform Proposed Margin				**25,374,447**	**21,274,770**	**3,669,857**	**0**	**72,539**	**357,281**
	Margin per Therm at Uniform Proposed Return									
45	Production				$0.005292	$0.005494	$0.005494	$0.000000	$0.005494	$0.001326
46	Underground Storage				$0.023130	$0.024430	$0.021051	$0.000000	$0.016636	$0.014525
47	Distribution				$0.225615	$0.270411	$0.127175	$0.000000	$0.098950	$0.044742
48	Common				$0.079225	$0.089791	$0.056019	$0.000000	$0.051229	$0.036284
49	Total Proposed Uniform Margin Melded Rat				**$0.333263**	**$0.390126**	**$0.209738**	**$0.000000**	**$0.172308**	**$0.096878**
50	**Margin to Cost Ratio at Proposed Rates**				**1.00**	**1.00**	**1.00**	**0.00**	**0.90**	**1.18**
51	**Current Margin to Proposed Cost Ratio**				**0.81**	**0.80**	**0.84**	**0.00**	**0.65**	**1.17**

Sumcost Company Base Case AVU-G-04-01 Method	AVISTA UTILITIES Summary by Classification with Unit Cost Analysis For the Year Ended December 31, 2007	Natural Gas Utility Idaho Jurisdiction	24-Mar-08

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Small Firm Service Sch 111	(i) Large Firm Service Sch 121	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Cost by Classification at Current Return by Schedule									
1	Commodity				61,244,377	45,912,258	13,138,531	1,600,679	346,154	246,756
2	Demand				10,406,504	7,936,479	2,178,520	202,479	11,637	77,388
3	Customer				10,209,119	9,358,263	632,949	115,842	9,209	92,856
4	Total Current Rate Revenue				81,860,000	63,207,000	15,950,000	1,919,000	367,000	417,000
	Revenue per Therm at Current Rates									
5	Commodity				$0.804372	$0.841915	$0.846664	$0.808690	$0.822247	$0.066908
6	Demand				$0.136677	$0.145535	$0.140387	$0.102296	$0.027643	$0.020984
7	Customer				$0.134085	$0.171607	$0.040788	$0.058525	$0.021875	$0.025178
8	Total Revenue per Therm at Current Rates				$1.075133	$1.159057	$1.027839	$0.969511	$0.871765	$0.113071
	Cost per Unit at Current Rates									
9	Commodity Cost per Therm				$0.804372	$0.841915	$0.846664	$0.808690	$0.822247	$0.066908
10	Demand Cost per Peak Day Therms				$18.80	$18.69	$21.99	$18.44	$5.63	$4.59
11	Customer Cost per Customer per Month				$12.10	$11.22	$67.43	$965.35	$767.41	$1,547.60
	Cost by Classification at Uniform Current Return									
12	Commodity				61,188,875	45,978,165	13,053,131	1,624,233	352,436	180,910
13	Demand				10,390,202	8,000,144	2,107,569	217,356	16,127	49,006
14	Customer				10,280,923	9,471,777	589,895	138,507	10,262	70,483
15	Total Uniform Current Cost				81,860,000	63,450,086	15,750,595	1,980,096	378,825	300,399
	Cost per Therm at Current Return									
16	Commodity				$0.803643	$0.843124	$0.841161	$0.820590	$0.837171	$0.049054
17	Demand				$0.136463	$0.146702	$0.135815	$0.109812	$0.038307	$0.013288
18	Customer				$0.135028	$0.173689	$0.038014	$0.069976	$0.024375	$0.019112
19	Total Cost per Therm at Current Return				$1.075133	$1.163515	$1.014989	$1.000378	$0.899854	$0.081454
	Cost per Unit at Uniform Current Return									
20	Commodity Cost per Therm				$0.803643	$0.843124	$0.841161	$0.820590	$0.837171	$0.049054
21	Demand Cost per Peak Day Therms				$18.77	$18.84	$21.28	$19.80	$7.80	$2.91
22	Customer Cost per Customer per Month				$12.18	$11.35	$62.84	$1,154.22	$855.14	$1,174.71
23	**Revenue to Cost Ratio at Current Rates**				**1.00**	**1.00**	**1.01**	**0.97**	**0.97**	**1.39**
	Cost by Classification at Proposed Return by Schedule									
24	Commodity				62,618,977	47,026,802	14,987,779	0	355,592	248,804
25	Demand				11,688,465	9,013,303	2,578,508	0	18,383	78,271
26	Customer				12,277,558	11,278,252	894,964	0	10,791	93,552
27	Total Proposed Rate Revenue				86,585,000	67,318,357	18,461,250	0	384,765	420,628
	Revenue per Therm at Proposed Rates									
28	Commodity				$0.822425	$0.862353	$0.856575	$0.000000	$0.844666	$0.067464
29	Demand				$0.153514	$0.165281	$0.147366	$0.000000	$0.043666	$0.021223
30	Customer				$0.161251	$0.206815	$0.051149	$0.000000	$0.025632	$0.025367
31	Total Revenue per Therm at Proposed Rate				$1.137190	$1.234449	$1.055089	$0.000000	$0.913964	$0.114054
	Cost per Unit at Proposed Rates									
32	Commodity Cost per Therm				$0.822425	$0.862353	$0.856575	$0.000000	$0.844666	$0.067464
33	Demand Cost per Peak Day Therms				$21.11	$21.23	$23.43	$0.00	$8.89	$4.64
34	Customer Cost per Customer per Month				$14.55	$13.52	$94.14	$0.00	$899.23	$1,559.20
	Cost by Classification at Uniform Proposed Return									
35	Commodity				62,602,284	47,041,993	14,987,779	0	359,480	213,032
36	Demand				11,690,498	9,027,977	2,578,508	0	21,161	62,852
37	Customer				12,292,218	11,304,415	894,964	0	11,442	81,397
38	Total Uniform Proposed Cost				86,585,000	67,374,384	18,461,250	0	392,084	357,281
	Cost per Therm at Proposed Return									
39	Commodity				$0.822206	$0.862632	$0.856575	$0.000000	$0.853903	$0.057764
40	Demand				$0.153541	$0.165550	$0.147366	$0.000000	$0.050266	$0.017042
41	Customer				$0.161444	$0.207294	$0.051149	$0.000000	$0.027180	$0.022071
42	Total Cost per Therm at Proposed Return				$1.137190	$1.235476	$1.055089	$0.000000	$0.931349	$0.096878
	Cost per Unit at Uniform Proposed Return									
43	Commodity Cost per Therm				$0.822206	$0.862632	$0.856575	$0.000000	$0.853903	$0.057764
44	Demand Cost per Peak Day Therms				$21.12	$21.26	$23.43	$0.00	$10.23	$3.73
45	Customer Cost per Customer per Month				$14.57	$13.55	$94.14	$0.00	$953.53	$1,356.62
46	**Revenue to Cost Ratio at Proposed Rates**				**1.00**	**1.00**	**1.00**	**0.00**	**0.98**	**1.18**
47	**Current Revenue to Proposed Cost Ratio**				**0.95**	**0.94**	**0.97**	**0.00**	**0.94**	**1.17**