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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-12-08
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-12-07
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation.

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your duties?

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

Q. What is your educational background and professional experience?

A. I am a graduate of Washington State University with a Bachelor of Arts degree in General Humanities in 1982, and a Master of Accounting degree in 1990. As an employee in the State and Federal Regulation Department at Avista since 1991, I have attended several ratemaking classes, including the EEI Electric Rates Advanced Course that specializes in cost allocation and cost of service issues. I have also been a member of the Cost of Service Working Group and the Northwest Pricing and Regulatory Forum, which are discussion groups made up of technical professionals from regional utilities and utilities throughout the United States and Canada concerned with cost of service issues.

Q. What is the scope of your testimony in this proceeding?

A. My testimony and exhibits will cover the Company's electric and natural gas cost of service studies performed for this proceeding. Additionally, I am sponsoring the electric and natural gas revenue normalization adjustments to the test year results of operations and the proposed Load Change Adjustment Rate (LCAR) to be used in the Power Cost Adjustment (PCA). A table of contents for my testimony is as follows:

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Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit 12 composed of six schedules as follows. Schedule 1, the proposed Load Change Adjustment Rate calculation; Schedule 2, the electric cost of service study process description; Schedule 3, the electric cost of service study summary results; Schedule 4, the cost of service workshop presentation; Schedule 5, the natural gas cost of service study process description; and Schedule 6, the natural gas cost of service study summary results.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

II. REVENUE NORMALIZATION

Electric Revenue Normalization

Q. Would you please describe the electric revenue adjustment included in Company witness Ms. Andrews pro forma results of operations?

A. Yes, I will. The electric revenue normalization adjustment represents the difference between the Company's actual recorded retail revenues during the twelve months ended June 2012 test period, and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $1,724,000, as shown in adjustment column 2.09 on page 7 of Ms. Andrews Exhibit No. 10, Schedule 1. The revenue normalization adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) at base tariff rates presently in effect, 2) adjusting customer loads and revenue to a 12-month calendar basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue[1].

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

A. Yes. The re-pricing of billed usage comprises the majority of the change in test year revenue. The combined impact of the rate increase effective October 1, 2011[2], and the elimination of revenue and amortization expense from adder schedules (Schedule 59 Residential Exchange, Schedule 91 Public Purpose Tariff Rider, Schedule 95 Optional Renewable Power, and Schedule 99 DSIT refund)[3], is an increase in net revenue of $2,097,000. Re-pricing of unbilled calendar usage and elimination of unbilled adder schedule revenue and expense results in a net revenue increase of $90,000[4]. Finally, the weather normalization adjustment increases revenue by $530,000. The combined impact of these elements is an increase of $2,717,000 which, after revenue-related expenses and income tax,

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

[2] IPUC Case No. AVU-E-11-01.

[3] Municipal Franchise Fee and Power Cost Adjustment revenues are eliminated in separate adjustments.

[4] The unbilled adjustment consists of removing June 2011 usage billed in July 2011 from the 12 Months Ended June 2012 test year, adding June 2012 usage billed in July 2012 to the 12 Months Ended June 2012 test year, and re-pricing the net adjustment to usage at October 1, 2011 base rates.

results in the increase to net operating income of $1,724,000.

Q. Would you please briefly discuss electric weather normalization?

A. Yes. The Company’s electric weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the twelve months ended June 2012 test period to the amount expected if weather had been normal. This adjustment incorporates the effect of both heating and cooling on weather-sensitive customer groups. The weather adjustment is developed from regression analysis of ten years of billed usage per customer and billing period heating and cooling degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day and use-per-customer-per-cooling-degree day) are applied to monthly test period customers and the difference between normal heating/cooling degree-days and monthly test period observed heating/cooling degree-days.

Q. Have the seasonal weather sensitivity factors been updated since the last rate case?

A. Yes. The factors used in the weather adjustment are based on regression analysis of monthly billed usage per customer from January 2001 through December 2010 which is the most recent completed analysis. Autoregressive terms were included in the regressions in order to correct for autocorrelation in the data.

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

A. Normal heating and cooling degree days are based on a rolling 30-year average of heating and cooling degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year.

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

A. Yes, the process for determining the weather sensitivity factors and the monthly adjustment calculation is consistent with the methodology presented in Case No. AVU-E-11-01.

Q. What was the impact of electric weather normalization on the twelve months ended June 2012 test year?

A. Weather was slightly warmer than normal during the winter, and cooler than normal during the spring of 2012 as well as the summer of 2011 (with offsetting impacts in June where it was necessary to both deduct heating degree-days and add cooling degree-days). Overall, the adjustment to normal required the addition of only 92 heating degree-days during the heating season[5] and 4 cooling degree-days during the cooling season. The total adjustment to Idaho sales volumes was an addition of 6,207,276 kWhs which is approximately 0.2% of billed usage.

Natural Gas Revenue Normalization

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

A. Yes. The natural gas revenue normalization adjustment is similar to the electric adjustment and represents the difference between the Company's actual recorded retail revenues during the twelve months ended June 2012 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

[5] The heating season includes the months of October through June. The cooling season includes the months of June through September. The early part of June typically requires heating whereas the end of June typically requires cooling, therefore, for normalization purposes June is treated as both a heating and cooling month.

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 prior deferred natural gas costs approved in the Company's last PGA filing, 2) Public Purposes Rider Adjustment Schedule 191, and 3) Deferred State Income Tax Adjustment Schedule 199[6].

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

A. Yes. Purchase gas costs are normalized using the natural gas costs approved by the Commission in Case No. AVU-G-12-05, the Company's 2012 PGA filing, as set forth under Schedule 150. These natural gas costs, effective October 1, 2012, are applied to the pro forma retail sales volumes so that there is a matching of revenues and natural gas costs.

Q. Have you determined the impact of each of the components of this adjustment?

A. Yes. The re-pricing of billed revenue and natural gas costs <u>increased</u> margin[7] by $240,000. Re-pricing

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

[7] The term "margin" in this context consists of revenues less gas costs and adder schedule amortization expenses but does not include the effect of revenue related expenses or income taxes.

unbilled revenue and natural gas costs decreased margin by $116,000, and the weather adjustment at present rates increased margin by $282,000.

The total net amount of the natural gas revenue normalization adjustment, which includes the related purchase gas cost normalization, is an increase to net operating income of $275,000, as shown in adjustment column 2.01, on page 5 of Ms. Andrews Exhibit No. 10, Schedule 2.

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

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

Q. In your discussion of electric weather normalization you indicated that the adjustment utilized sensitivity factors from the ten year period January 2001

through December 2010. Is this true for natural gas as well?

A. Yes, the natural gas weather adjustment utilized updated weather sensitivity factors.

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

A. Normal heating degree-days are based on a rolling 30-year average of heating degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year.

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

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation are consistent with the methodology presented in Case No. AVU-G-11-01.

Q. What was the impact of natural gas weather normalization on the twelve months ended June 2012 test year?

A. Weather was slightly warmer than normal during the fall and winter months, largely offset by a cooler than normal spring. The adjustment to normal required the addition of 92 heating degree-days from October through June.[8] The adjustment to sales volumes was an addition of 818,604 therms which is approximately 0.7% of billed usage.

III. PROPOSED LOAD CHANGE ADJUSTMENT RATE

Q. What is the Load Change Adjustment Rate?

A. The Load Change Adjustment Rate (LCAR) is part of the Power Cost Adjustment (PCA) mechanism that prices the change in power supply-related costs associated with the change in actual retail loads from the retail loads that were used to set the PCA base costs. The LCAR determination process for all Idaho investor-owned utilities was established in IPUC Case No. GNR-E-10-03, Order No. 32206 which was approved on March, 15, 2011.

Q. How is the rate determined?

A. The proposed LCAR in this case is determined by computing the proposed revenue requirement on the production and transmission costs contained within Ms. Andrews' Idaho electric pro forma total results of

[8] Heating degree days that occur during July through September do not impact the natural gas weather normalization adjustment as the seasonal sensitivity factor is zero for summer months.

operations. The production/transmission revenue requirement amount is then divided by the Idaho normalized retail load used to set rates in order to arrive at the average production and transmission cost-per-kWh embedded in proposed rates. This amount is then multiplied by the proportion of production and transmission costs classified as energy-related in the cost of service study.

Q. Do you have an exhibit schedule that shows the calculation of the proposed LCAR?

A. Yes. Exhibit No. 12, Schedule 1 begins with the identification of the production and transmission revenue, expense and rate base amounts included in each of Ms. Andrews' actual, restating, and pro forma adjustments to results of operations. The "Pro Forma Total Production and Transmission Costs" on line 32 at the bottom of page 1 shows the resulting production and transmission cost components.

Page 2 shows the revenue requirement calculation on the production and transmission cost components. The rate of return and debt cost percentages on Line 2 are inputs from the proposed cost of capital. The normalized retail load on Line 10 comes from the workpapers supporting the revenue normalization and energy efficiency load adjustments. Line 11 represents the average total production and transmission cost-per-kWh proposed to be embedded in Idaho customer retail rates. Lines 12 and 13 are values taken from the cost of service study supporting report titled <u>Functional Cost Summary by Classification at Uniform Requested Return</u> representing total costs at unity. Line 12 shows the amount of production and transmission costs classified as energy related, while Line 13 shows the total production and transmission costs in the study.

The resulting load change adjustment rate on Line 14 is $0.02768 per kWh or $27.68 per MWh. The calculation of the load change adjustment rate will be revised based on the final production and transmission costs, and rate of return, that are approved by the Commission in this case.

IV. ELECTRIC COST OF SERVICE

Q. Please briefly summarize your testimony related to the electric cost of service study.

A. I believe the Base Case cost of service study presented in this case is a fair and reasonable representation of the costs to serve each customer group. The Base Case study shows Residential Service Schedule 1, Extra Large General Service Schedule 25, Pumping Service Schedule 31 and the Street and Area Lighting Schedules provide less than the overall rate of return under present rates. General Service Schedule 11, Large General Service Schedule 21 and Extra Large General Service to Clearwater Paper Schedule 25P provide more than the overall rate of return under present rates.

Q. What is an electric cost of service study and what is its purpose?

A. An electric cost of service study is an engineering-economic study, which separates the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. The groups are made up of customers with similar load characteristics and facilities requirements. Costs are assigned or allocated to each group based on (among other things), test period load and facilities requirements, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers. Exhibit No. 12, 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. 12, Schedule 3 is based on the twelve months ended June 30, 2012 test year pro forma results of operations presented by Ms. Andrews in Exhibit No. 10, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 12, Schedule 3?

A. Yes. Exhibit No. 12, 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 Company witness Mr. Ehrbar for his work on rate spread and rate design. The results will be discussed in more detail later in my testimony.

Pages 2 and 3 are both summaries that show the revenue-to-cost relationship at current and proposed revenue. Costs by category are shown first at the existing schedule returns (revenue); next the costs are shown as if all schedules were providing equal recovery (cost). These comparisons show how far current and proposed rates are from rates that would be in alignment with the cost study. Page 2 shows the costs segregated into production, transmission, distribution, and common functional categories. Line 44 on page 2 shows the target change in revenue which would produce unity in this cost study. Page 3 segregates the costs into demand, energy, and customer classifications. Page 4 is a summary identifying specific customer related costs embedded in the study.

The Excel model used to calculate the cost of service and supporting schedules has been included in its entirety both electronically and in hard copy in the workpapers accompanying this case.

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

A. In most respects, yes. In the last case (Case No. AVU-E-11-01) the Company's electric Base Case cost of service study was prepared using the methodology presented in Case No. AVU-E-04-01 through Case No. AVU-E-09-01 <u>except</u> that the <u>peak credit</u> classification of production and transmission costs was revised. While a revision to the peak credit classification of production and transmission costs was also proposed in Case No. AVU-E-10-01, only the classification of transmission costs as 100% demand-related was accepted as part of the settlement in that case. In this case the Company's Base Case cost of service study utilizes the study methodology accepted in the Settlement from Case No. AVU-E-10-01.[9]

Q. Given that the specific details of this methodology are described in Exhibit No. 12, Schedule 2, would you please give a brief overview of the key elements and the history associated with those elements?

A. Yes. Production costs are classified to energy and demand in this case using the Company's traditional peak credit assignments derived from replacement cost of plant investment. Transmission costs are classified as 100% demand and allocated by the average of the 12 monthly coincident peaks, as accepted in the Settlement in Case No. AVU-E-10-01.

Distribution costs are classified and allocated by the basic customer theory[10] 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.

[9] This methodology contains only one methodological difference from the studies presented from Case Nos. AVU-E-04-01 through AVU-E-09-01. Namely, transmission costs are classified as 100% demand-related.
[10] Basic customer theory classifies only meters, services and street lights as customer-related plant; all other distribution facilities are considered demand-related

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. The settlement in Case No. AVU-E-11-01 required the convening of a public workshop regarding cost of service issues before the next rate case. Please explain.

A. In Order No. 32371 from Case No. AVU-E-11-01 and AVU-G-11-01, the Commission approved an all-party Settlement Stipulation. In Section 10 of the Settlement Stipulation, beginning on page 5 it states:

> The Parties have agreed to exchange information and convene a public workshop, prior to the Company's next general rate case, with respect to the method of allocation of demand and energy among the customer classes such as the possible use of a revised peak credit method for classifying production costs, as well as consideration of the use of a 12 Coincident Peak (CP) (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs.

The workshop was convened on September 18, 2012 at the Idaho Public Utilities Commission, and was attended by the key stakeholders regarding cost of service issues.[11] The Company's presentation from the workshop is included as Schedule 4 of Exhibit No. 12.

Q. Was any consensus reached among the Parties regarding the alternative peak credit classification approach?

A. No, there was not. Even though the system load factor approach to production peak credit, in the Company's view, is simple and straightforward, related to the test year under evaluation, and should provide a stable relationship over time, the Parties could not agree that it provides for a <u>better</u> representation of production cost-causation than the traditional peak credit methodology. In fact, certain parties suggested potentially removing certain items, such as fuel, from the system load factor methodology and classifying those costs as 100% energy related.

Q. Was consensus reached among the parties as it relates to the demand allocation factor for transmission costs?

A. No consensus was reached. The general sentiment among the parties on this issue, and even the peak credit

[11] Parties attending the workshop included Avista, IPUC Staff, Idaho Forest Group, Clearwater Paper, Idaho Conservation League, and Community Action Partnership Association of Idaho (CAPAI).

issue, is that there should be stability in methodology over time, and that modifications to existing practices should be well founded. Enough changes occur in cost recovery relationships stemming from test year differences without layering on changes to how the cost elements are treated through a methodology change.

Q. Did the workshop influence your decision to propose the traditional peak credit methodology and unweighted 12CP demand for transmission in this case?

A. Yes it did. First, it is important to note that the Company believes that the revised peak credit methodology for classifying production costs into energy and demand components which it proposed in Case No. AVU-E-11-01 is a preferable methodology. That being said, some parties at the September 2012 workshop, and IPUC Staff in particular, believe that methodological consistency is very important, and that the Company's traditional peak credit methodology is a valid approach for production cost classification.

With that in mind, as well as to potentially limit the number of issues in this case, Avista is presenting the prior traditional peak credit methodology in the cost of service study. This methodology includes using 12 CP for allocating transmission costs instead of a weighted 12 CP as proposed in the last case. The Company, however, is proposing to continue to employ the recent change to classify transmission costs as 100% demand-related.

Q. What are the results of the Company's electric cost of service study presented in this case?

A. The following Illustration shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates for each rate schedule:

Illustration 1

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	5.74%	0.78
General Service Schedule 11/12	10.26%	1.40
Large General Service Schedule 21/22	8.40%	1.15
Extra Large General Service Schedule 25	7.10%	0.97
Extra Large General Service Clearwater Paper Schedule 25P	8.75%	1.20
Pumping Service Schedule 31/32	6.92%	0.95
Lighting Service Schedules 41 - 49	5.51%	0.75
Total Idaho Electric System	7.32%	1.00

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

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 group's test year load and facilities requirements, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are one of the key inputs in determining the appropriate rate spread among the groups of customers. Exhibit No. 12, Schedule 5 explains the basic concepts involved in performing a natural gas cost of service study. It also details the specific methodology and assumptions utilized in the Company's Base Case cost of service study.

Q. What is the basis for the natural gas cost of service study provided in this case?

A. The cost of service study provided by the Company as Exhibit 12, Schedule 6 is based on the twelve months ended June 2012 test year pro forma results of operations presented by Ms. Andrews in Exhibit 10, Schedule 2.

Q. Would you please explain the natural gas cost of service study presented in Schedule 6?

A. Yes. Exhibit 12, Schedule 6 is composed of a series of summaries of the cost of service study results. Page 1 shows the results of the study by FERC account category. The rate of return, and the ratio of each schedule's return to the overall return, are shown on lines 38 and 39. This summary is provided to Mr. Ehrbar for his work on rate spread and rate design, and the results will be presented later in my testimony. Additional summaries show the costs organized by functional category (page 2) and classification (page 3), including margin and unit cost analysis at current and proposed rates. Finally, page 4 is a summary identifying specific customer related costs embedded in the study.

The Excel model used to calculate the natural gas cost of service and supporting schedules has been included in its entirety both electronically and hard copy in the natural gas workpapers accompanying this case.

Q. Does the Natural Gas Base Case cost of service study utilize the methodology from the Company's last natural gas case in Idaho?

A. Yes. The Base Case cost of service study was prepared using the methodology accepted by the Idaho Commission in Case No. AVU-G-04-01, and presented in AVU-G-08-01, AVU-G-09-01, AVU-G-10-01 and AVU-G-11-01.

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

A. Allocations of natural gas costs reflect the current Purchased Gas Adjustment 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.

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 12, Schedule 5.

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

A. I believe the Base Case cost of service study presented in this filing is a fair and reasonable representation of the costs to serve each customer group. The study indicates that General Service (primarily residential) Schedule 101, Interruptible Service Schedules 131/132 and Transportation Service Schedule 146 are providing less than the overall return (unity), and Large General Service Schedules 111/112 are providing more than unity.

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

Illustration 2

Customer Class	Rate of Return	Return Ratio
General Firm Service Schedule 101	5.40%	0.92
Large Firm Service Schedule 111/112	7.98%	1.37
Interruptible Service Schedule 131/132	5.35%	0.92
Transportation Service Schedule 146	4.69%	0.80
Total Idaho Natural Gas System	5.84%	1.00

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

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

A. Yes, it does.

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NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 12
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED JUNE 30, 2012

				Production / Transmission					
							Accumulated	Deferred	Deferred
Line	Column	Description of Adjustment	(000's)	**Revenue**	**Expense**	**Plant**	**Depreciation**	**Debits/Credits**	**Tax**
1	1.00	Per Results Report		101,316	226,548	585,254	(213,725)	1,765	(61,642)
2	1.01	Deferred FIT Rate Base		-	-	-	-	-	(285)
3	1.02	Deferred Debits and Credits		-	(64)	-	-	(414)	-
4	1.03	Working Capital		-	-	-	-	-	-
5	1.04	Restate 2011 Capital		-	236	9,873	(4,733)	-	(835)
6	2.01	Eliminate B & O Taxes		-	-	-	-	-	-
7	2.02	Uncollect. Expense		-	-	-	-	-	-
8	2.03	Regulatory Expense		-	-	-	-	-	-
9	2.04	Injuries and Damages		-	-	-	-	-	-
10	2.05	FIT/DFIT/ ITC/PTC Expense		-	-	-	-	-	-
11	2.06	ID PCA		-	(9,871)	-	-	-	-
12	2.07	Nez Perce Settlement Adjustment		-	(18)	-	-	-	-
13	2.08	CS2 Levelized		-	235	-	-	-	-
14	2.09	Revenue Normalization		-	9,635	-	-	-	-
15	2.10	Misc Restating		-	-	-	-	-	-
16	2.11	Restate Incentives		-	-	-	-	-	-
17	2.12	Colstrip / CS2 Maintenance		-	1,339	-	-	-	-
18	2.13	Restate Debt Interest		-	-	-	-	-	-
19	3.01	Pro Forma Power Supply		(73,823)	(76,210)	-	-	-	-
20	3.02	Pro Forma Transmission Rev/Exp		371	3	-	-	-	-
21	3.03	Pro Forma Labor Non-Exec		-	290	-	-	-	-
22	3.04	Pro Forma Generation Major O&M		-	921	-	-	-	-
23	3.05	Pro Forma Employee Benefits		-	353	-	-	-	-
24	3.06	Pro Forma Insurance		-	-	-	-	-	-
25	3.07	Pro Forma Property Tax		-	380	-	-	-	-
26	3.08	Pro Forma IS/IT Costs		-	80	-	-	-	-
27	3.09	Planned Capital Add 2012		-	534	23,728	(13,617)	-	(1,765)
28	3.10	Planned Capital Add 2013 AMA		-	128	6,735	(6,162)	-	(661)
29	3.11	PF Energy Efficiency Load Adj.		-	(976)	-	-	-	-
30	3.12	O&M Offsets		-	(35)	-	-	-	-
31	3.13	Depreciation Study		-	(1,780)	-	-	-	-
32	Pro Forma Total			27,864	151,728	625,590	(238,237)	1,351	(65,188)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED JUNE 30, 2012

Proposed Production and Transmission Revenue Requirement

Calculation of Load Change Adjustment Rate

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	323,516	
2	Cost of Capital	Proposed Rate of Return	8.460%	3.01%
3	Rate Base	Net Operating Income Requirement	$27,369	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,408)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	123,864	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($43,352)	
7	Total Prod/Trans	Net Operating Income Requirement	$104,473	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$160,727	
10	Test Year WA Normalized Retail Load MWh		3,364,879	with EELA Billing Determinant Adjustment
11	Prod/Trans Rev Requirement per kWh		$ 0.04777	
12	Cost of Service Energy Classified Production/Transmission Costs		$94,413	Company Case at Unity AVU-E-12-08
13	Cost of Service Total Production/Transmission Costs		$162,919	Company Case at Unity AVU-E-12-08
14	Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02768**	

1. ELECTRIC COST OF SERVICE

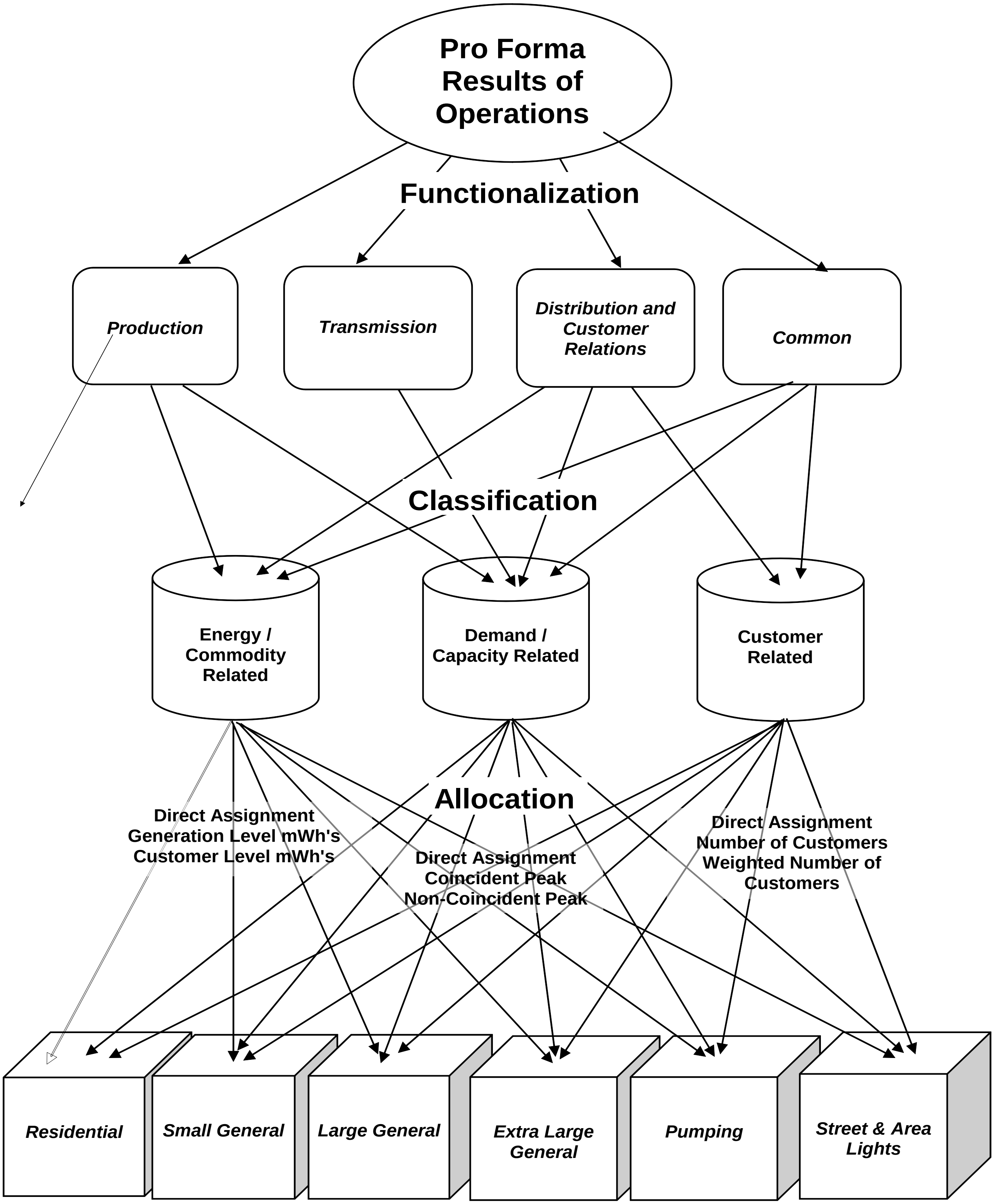
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by customers recovers the cost to serve those customers. The study results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

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. This study includes 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 [1]

1 Customer classes shown in this flowchart are illustrative and may not match the Company's actual rate schedules.

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 Classification (Traditional Peak Credit)

This study utilizes a Peak Credit methodology to classify production 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. 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 42.00% to demand and 58.00% to energy. The peak credit ratio for hydro plant is 41.83% to demand and 58.17% 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. 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 Allocation

Production 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 kilowatt-hour sales adjusted for losses to reflect generation level consumption.

Transmission Classification and Allocation

Transmission costs are classified as 100% demand related due in part to the fact that the facilities are designed for meeting system peak loads. These costs are then allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads (12CP). The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

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 (if any) recorded in Account 908 would be considered separately from the other customer information costs.

Any demand side management investment and amortization included in base rates would be 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. At this point in time, the Company's demand side management investments in base rates have been fully amortized except for some minor outstanding loan balances that will remain on the books until satisfied. All current demand side management costs are managed through the Schedule 91 Public Purpose Tariff Rider balancing account which is not included in this cost study.

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-12-08 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Production Plant			
1	Thermal Production	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Hydro Production	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Production (Coyote Springs)	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other Production	P = Production	Demand	D01 Coincident Peak Demand (12CP)
	Transmission Plan			
5	All Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
	Distribution Plan			
6	360 Land	D = Distribution	Demand	D03 Non-coincident Peak Demand (NCP)
7	361 Structures	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
8	362 Station Equipment	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
9	364 Poles Towers & Fixtures	D = Distribution	Demand	D04/D05/D07/D08 Direct Assign Large & Lights / NCP Excl DA / NCP Secondary
10	365 Overhead Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
11	366 Underground Conduit	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
12	367 Underground Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
13	368 Line Transformers	D = Distribution	Demand	D07 Non-coincident Peak Demand Secondary
14	369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
15	370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
16	373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
	General Plant			
17	All General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Intangible Plant			
18	301 Organization	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
19	302 Franchises & Consents - Hydro Relicensing	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
20	303 Misc Intangible Plant - Transmission Agreements	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
21	303 Misc Intangible Plant - Software	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Reserve for Depreciation/Amortizatio			
22	Intangible	P/T/O	Follows Related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
23	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
24	Transmission	T = Transmission	Follows Related Plant	D01 Coincident Peak Demand (12CP)
25	Distribution	D = Distribution	Follows Related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
26	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Other Rate Base			
27	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
28	282/190 Accumulated Deferred Income Tax	P/T/D/O	Follows Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
29	Gain on Sale of General Office Building	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
30	Hydro Relicensing Related Settlements	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
31	Demand Side Management Investment	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
32	Working Capital	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
	Production O&M			
33	Thermal	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
34	Thermal Fuel (501)	P = Production	Energy	E02 Annual Generation Level Consumption
35	Hydro	P = Production	Demand/Energy by Hydro Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption

IPUC Case No. AVU-E-12-08 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Production O&M (continued)			
1	Water for Power (536)	P = Production	Energy	E02 Annual Generation Level Consumption
2	Other (Coyote Springs)	P = Production	Demand/Energy by Thermal Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Fuel (547)	P = Production	Energy	E02 Annual Generation Level Consumption
4	Other	P = Production	Demand	D01 Coincident Peak Demand (12CP)
5	Purchased Power and Other Expenses (555 and 557)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
6	System Control & Misc (556)	P = Production	Energy	E02 Annual Generation Level Consumption
	Transmission O&M			
7	All Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
	Distribution O&M			
8	580 OP Super & Engineering	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
9	581 Load Dispatching	D = Distribution	Demand	D03 Non-coincident Peak Demand
10	582 Station Expenses	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
11	583 Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
12	584 Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
13	585 Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
14	586 Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
15	587 Customer Installations	D = Distribution	Customer	S13 Sum of Account 369 Services
16	588 Misc Operating Expense	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
17	589 Rents	D = Distribution	Demand	D03 Non-coincident Peak Demand
18	590 MT Super & Engineering	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
19	591 MT of Structures	D = Distribution	Demand	S08 Sum of Account 361 Structures & Improvements
20	592 MT of Station Equipment	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
21	593 MT of Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
22	594 MT of Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
23	595 MT of Line Transformers	D = Distribution	Demand	S12 Sum of Account 368 Line Transformers
24	596 MT of Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
25	597 MT of Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
26	598 Misc Maintenance Expense	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
	Customer Accounts Expenses			
27	901 Supervision	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
28	902 Meter Reading	C = Customer Relations	Customer	C03/C06 Customers Weighted by Est. Meter Reading Time/Direct Assign Handbilled Cus
29	903 Customer Records & Collections	C = Customer Relations	Customer	C01/C06 All Customers unweighted / Direct Assign Handbilled Cust
30	904 Uncollectible Accounts	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
31	905 Misc Cust Accounts	C = Customer Relations	Customer	C01 All Customers unweighted
	Customer Service & Info Expenses			
32	907 Supervision	C = Customer Relations	Customer	C01 All Customers unweighted
33	908 Customer Assistance	C = Customer Relations	Customer	C01 All Customers unweighted
34	908 DSM Amortization Expenses	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
35	909 Advertising	C = Customer Relations	Customer	C01 All Customers unweighted
36	910 Misc Cust Service & Info	C = Customer Relations	Customer	C01 All Customers unweighted
	Sales Expenses			
37	911 - 916	C = Customer Relations	Energy	E02 Annual Generation Level Consumption

IPUC Case No. AVU-E-12-08 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 - 927 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
2	920 - 927 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
3	920 - 927 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
4	920 - 927 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01 All Customers unweighted
5	920 - 935 Assigned to Other	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
6	928 FERC Commission Fees	P = Production	Energy	E02 Annual Generation Level Consumption
7	928 IPUC Commission Fees	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
	Depreciation & Amortization Expens			
8	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
9	Production	P = Production	Demand/Energy by Peak Credit as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
10	Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
11	Distribution	D = Distribution	Demand/Customer as in related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
12	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			
13	Property Tax	P/T/D/O	Demand/Energy/Customer from related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
14	State kWh Generation Taxes	P = Production	Demand/Energy by 1/2 Fuel, 1/2 Transmission	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
15	Misc Production Taxes	P = Production	Demand/Energy by 1/2 Fuel, 1/2 Transmission	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
16	Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
17	Idaho State Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
18	Federal Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
19	Deferred FIT	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
	Other Income Related Item:			
20	CS2 Levelized Return and Boulder Write-off Amort.	P = Production	Demand/Energy by Peak Credit as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Operating Revenue:			
21	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
22	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
23	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
24	Sales of Water & Water Power (453)	P = Production	Demand	D01 Coincident Peak Demand (12CP)
25	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
26	Rent from Transmission Property (454)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
27	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
28	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
29	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
30	Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Salaries & Wages (allocation factor input			
	Operation & Maintenance Expenses			
31	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
32	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
33	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
34	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
35	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
36	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
37	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: AVU-E-12-08 Company Case
AVU-E-10-01 Settlement Method
Transmission By Demand 12 CP

AVISTA UTILITIES
Cost of Service Basic Summary
For the Twelve Months Ended June 30, 2012

Idaho Jurisdiction
Electric Utility

10-10-12

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
				Residential	General	Large Gen	Extra Large	Extra Large	Pumping	Street &
			System	Service	Service	Service	Gen Service	Service CP	Service	Area Lights
	Description		Total	Sch 1	Sch 11-12	Sch 21-22	Sch 25	Sch 25P	Sch 31-32	Sch 41-49
	Plant In Service									
1	Production Plant		402,565,000	149,638,011	40,682,236	80,301,297	34,458,283	89,941,661	6,239,766	1,303,746
2	Transmission Plant		193,225,000	78,729,256	19,788,854	37,732,611	15,884,481	37,989,699	2,676,142	423,958
3	Distribution Plant		449,614,000	225,605,267	64,270,329	110,145,165	9,287,020	2,737,865	15,430,461	22,137,894
4	Intangible Plant		54,867,000	23,810,109	6,166,529	9,958,073	3,823,947	9,725,364	922,792	460,186
5	General Plant		88,487,000	48,015,959	11,628,726	13,352,814	3,786,351	8,559,695	1,659,918	1,483,536
6	Total Plant In Service		1,188,758,000	525,798,603	142,536,673	251,489,960	67,240,083	148,954,284	26,929,078	25,809,319
	Accum Depreciation									
7	Production Plant		(174,598,000)	(64,910,989)	(17,644,862)	(34,826,500)	(14,943,998)	(39,000,750)	(2,705,768)	(565,134)
8	Transmission Plant		(66,055,000)	(26,914,017)	(6,764,925)	(12,899,095)	(5,430,195)	(12,986,982)	(914,853)	(144,932)
9	Distribution Plant		(151,682,000)	(75,312,738)	(20,623,837)	(37,302,715)	(2,961,053)	(731,153)	(5,147,372)	(9,603,132)
10	Intangible Plant		(11,443,000)	(5,817,267)	(1,434,259)	(1,838,075)	(587,737)	(1,397,545)	(207,226)	(160,891)
11	General Plant		(34,403,000)	(18,668,200)	(4,521,151)	(5,191,462)	(1,472,101)	(3,327,937)	(645,362)	(576,786)
12	Total Accumulated Depreciation		(438,181,000)	(191,623,212)	(50,989,034)	(92,057,846)	(25,395,084)	(57,444,367)	(9,620,582)	(11,050,875)
13	Net Plant		750,577,000	334,175,391	91,547,639	159,432,113	41,844,999	91,509,917	17,308,496	14,758,444
14	Accumulated Deferred FIT		(119,554,000)	(52,622,048)	(14,256,245)	(25,204,201)	(6,885,548)	(15,403,257)	(2,673,478)	(2,509,223)
15	Miscellaneous Rate Base		8,007,000	3,223,674	914,043	1,813,323	519,015	1,185,858	181,919	169,167
16	Total Rate Base		639,030,000	284,777,017	78,205,437	136,041,236	35,478,467	77,292,518	14,816,938	12,418,388
17	Revenue From Retail Rates		248,720,000	99,497,000	32,432,000	51,400,000	16,036,000	41,091,000	4,859,000	3,405,000
18	Other Operating Revenues		29,727,000	11,482,225	3,089,386	5,992,225	2,405,525	6,094,169	487,054	176,415
19	Total Revenues		278,447,000	110,979,225	35,521,386	57,392,225	18,441,525	47,185,169	5,346,054	3,581,415
	Operating Expenses									
20	Production Expenses		121,242,000	43,633,193	12,198,017	24,352,993	10,513,928	28,163,848	1,945,460	434,561
21	Transmission Expenses		10,671,000	4,347,884	1,092,855	2,083,813	877,233	2,098,011	147,792	23,413
22	Distribution Expenses		11,311,000	5,419,369	1,684,669	2,570,085	255,627	97,643	373,434	910,172
23	Customer Accounting Expenses		4,343,000	3,248,473	675,400	175,647	64,162	113,336	53,439	12,544
24	Customer Information Expenses		601,000	490,809	96,818	6,057	44	5	6,640	626
25	Sales Expenses		4,000	1,357	399	813	355	991	68	17
26	Admin & General Expenses		23,863,000	12,589,773	3,107,324	3,796,522	1,066,358	2,428,810	461,067	413,147
27	Total O&M Expenses		172,035,000	69,730,858	18,855,482	32,985,930	12,777,706	32,902,644	2,987,901	1,794,479
28	Taxes Other Than Income Taxes		9,171,000	3,795,741	1,035,428	1,938,010	614,626	1,454,900	187,375	144,920
29	Other Income Related Items		397,000	141,952	39,907	79,851	34,515	92,913	6,413	1,450
	Depreciation Expense									
30	Production Plant Depreciation		8,771,000	3,284,857	887,308	1,746,702	748,439	1,941,191	134,816	27,687
31	Transmission Plant Depreciation		3,550,000	1,446,443	363,568	693,237	291,835	697,961	49,167	7,789
32	Distribution Plant Depreciation		13,770,000	6,991,324	2,124,901	3,257,960	269,195	48,617	474,761	603,243
33	General Plant Depreciation		9,283,000	5,037,261	1,219,947	1,400,818	397,219	897,981	174,139	155,635
34	Amortization Expense		472,000	185,047	48,113	93,090	39,422	98,111	6,905	1,312
35	Total Depreciation Expense		35,846,000	16,944,931	4,643,837	7,191,808	1,746,110	3,683,860	839,788	795,666
36	Income Tax		14,195,000	4,008,667	2,920,617	3,773,418	747,990	2,285,559	298,625	160,125
37	Total Operating Expenses		231,644,000	94,622,149	27,495,271	45,969,016	15,920,947	40,419,875	4,320,102	2,896,640
38	Net Income		46,803,000	16,357,077	8,026,115	11,423,208	2,520,578	6,765,294	1,025,952	684,775
39	Rate of Return		7.32%	5.74%	10.26%	8.40%	7.10%	8.75%	6.92%	5.51%
40	Return Ratio		1.00	0.78	1.40	1.15	0.97	1.20	0.95	0.75
41	Interest Expense		19,235,000	8,571,876	2,354,008	4,094,883	1,067,913	2,326,529	445,994	373,797
42	Revenue Related Operating Expenses		1,259,000	503,646	164,168	260,183	81,173	207,999	24,596	17,236

Sumcost
Scenario: AVU-E-12-08 Company Case
AVU-E-10-01 Settlement Method
Transmission By Demand 12 CP

AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Twelve Months Ended June 30, 2012

Idaho Jurisdiction
Electric Utility

10-10-12

	(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 CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule											
1	Production				136,364,788	47,060,028	14,621,765	27,931,027	11,690,137	32,448,878	2,150,089	462,864
2	Transmission				21,689,704	7,685,638	2,701,310	4,544,899	1,736,647	4,692,231	288,429	40,550
3	Distribution				55,412,989	26,385,511	10,099,956	13,372,398	1,092,762	369,065	1,760,044	2,333,253
4	Common				35,252,519	18,365,822	5,008,969	5,551,676	1,516,454	3,580,826	660,438	568,334
5	Total Current Rate Revenue				248,720,000	99,497,000	32,432,000	51,400,000	16,036,000	41,091,000	4,859,000	3,405,000
	Expressed as $/kWh											
6	Production				$0.04053	$0.04180	$0.04412	$0.04129	$0.03896	$0.03770	$0.03809	$0.03328
7	Transmission				$0.00645	$0.00683	$0.00815	$0.00672	$0.00579	$0.00545	$0.00511	$0.00292
8	Distribution				$0.01647	$0.02344	$0.03048	$0.01977	$0.00364	$0.00043	$0.03118	$0.16774
9	Common				$0.01048	$0.01631	$0.01512	$0.00821	$0.00505	$0.00416	$0.01170	$0.04086
10	Total Current Melded Rates				$0.07392	$0.08837	$0.09787	$0.07599	$0.05344	$0.04774	$0.08608	$0.24480
	Functional Cost Components at Uniform Current Return											
11	Production				135,669,121	48,969,282	13,654,976	27,233,957	11,751,370	31,407,161	2,170,311	482,063
12	Transmission				21,490,270	8,756,180	2,200,894	4,196,579	1,766,654	4,225,172	297,638	47,152
13	Distribution				56,126,482	29,467,448	8,428,038	12,355,724	1,110,937	330,840	1,813,571	2,619,924
14	Common				35,434,128	19,156,149	4,648,672	5,391,551	1,525,634	3,446,346	667,697	598,078
15	Total Uniform Current Cost				248,720,000	106,349,060	28,932,579	49,177,812	16,154,596	39,409,519	4,949,216	3,747,217
	Expressed as $/kWh											
16	Production				$0.04032	$0.04349	$0.04121	$0.04026	$0.03916	$0.03649	$0.03845	$0.03466
17	Transmission				$0.00639	$0.00778	$0.00664	$0.00620	$0.00589	$0.00491	$0.00527	$0.00339
18	Distribution				$0.01668	$0.02617	$0.02543	$0.01827	$0.00370	$0.00038	$0.03213	$0.18835
19	Common				$0.01053	$0.01701	$0.01403	$0.00797	$0.00508	$0.00400	$0.01183	$0.04300
20	Total Current Uniform Melded Rates				$0.07392	$0.09446	$0.08731	$0.07271	$0.05383	$0.04578	$0.08768	$0.26940
21	Revenue to Cost Ratio at Current Rates				1.00	0.94	1.12	1.05	0.99	1.04	0.98	0.91
	Functional Cost Components at Proposed Return by Schedule											
22	Production				140,184,410	48,492,742	14,991,954	28,713,644	12,016,444	33,285,836	2,212,176	471,615
23	Transmission				23,642,289	8,489,027	2,892,935	4,935,990	1,896,563	5,067,511	316,703	43,559
24	Distribution				59,930,158	28,698,341	10,740,181	14,513,912	1,189,616	399,779	1,924,395	2,463,934
25	Common				36,356,143	18,958,890	5,146,930	5,731,454	1,565,377	3,688,875	682,726	581,892
26	Total Proposed Rate Revenue				260,113,000	104,639,000	33,772,000	53,895,000	16,668,000	42,442,000	5,136,000	3,561,000
	Expressed as $/kWh											
27	Production				$0.04166	$0.04307	$0.04524	$0.04245	$0.04004	$0.03867	$0.03919	$0.03391
28	Transmission				$0.00703	$0.00754	$0.00873	$0.00730	$0.00632	$0.00589	$0.00561	$0.00313
29	Distribution				$0.01781	$0.02549	$0.03241	$0.02146	$0.00396	$0.00046	$0.03409	$0.17714
30	Common				$0.01080	$0.01684	$0.01553	$0.00847	$0.00522	$0.00429	$0.01210	$0.04183
31	Total Proposed Melded Rates				$0.07730	$0.09294	$0.10191	$0.07968	$0.05554	$0.04931	$0.09099	$0.25601
	Functional Cost Components at Uniform Requested Return											
32	Production				139,481,645	50,383,935	14,040,165	27,994,752	12,077,948	32,260,841	2,229,521	494,483
33	Transmission				23,437,170	9,549,442	2,400,283	4,576,766	1,926,703	4,607,949	324,602	51,424
34	Distribution				60,656,479	31,751,124	9,094,204	13,465,411	1,207,871	362,167	1,970,308	2,805,394
35	Common				36,537,706	19,741,741	4,792,223	5,566,316	1,574,598	3,556,553	688,952	617,321
36	Total Uniform Cost				260,113,000	111,426,243	30,326,875	51,603,244	16,787,120	40,787,511	5,213,383	3,968,622
	Expressed as $/kWh											
37	Production				$0.04145	$0.04475	$0.04237	$0.04139	$0.04025	$0.03748	$0.03950	$0.03555
38	Transmission				$0.00697	$0.00848	$0.00724	$0.00677	$0.00642	$0.00535	$0.00575	$0.00370
39	Distribution				$0.01803	$0.02820	$0.02744	$0.01991	$0.00403	$0.00042	$0.03491	$0.20169
40	Common				$0.01086	$0.01753	$0.01446	$0.00823	$0.00525	$0.00413	$0.01221	$0.04438
41	Total Uniform Melded Rates				$0.07730	$0.09897	$0.09152	$0.07629	$0.05594	$0.04738	$0.09236	$0.28532
42	Revenue to Cost Ratio at Proposed Rates				1.00	0.94	1.11	1.04	0.99	1.04	0.99	0.90
43	Current Revenue to Proposed Cost Ratio				0.96	0.89	1.07	1.00	0.96	1.01	0.93	0.86
44	Target Revenue Increase				11,393,000	11,929,000	(2,105,000)	203,000	751,000	(303,000)	354,000	564,000

	(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 CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Cost Classifications at Current Return by Schedule									
1	Energy		99,505,249	32,531,602	10,437,176	20,531,033	8,737,229	25,198,840	1,669,300	400,069
2	Demand		121,741,170	48,056,898	16,472,134	30,165,949	7,258,252	15,886,884	2,788,487	1,112,567
3	Customer		27,473,580	18,908,500	5,522,690	703,018	40,519	5,276	401,213	1,892,364
4	Total Current Rate Revenue		248,720,000	99,497,000	32,432,000	51,400,000	16,036,000	41,091,000	4,859,000	3,405,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.02957	$0.02889	$0.03150	$0.03035	$0.02912	$0.02927	$0.02957	$0.02876
6	Demand	$/kW/mo	$16.47	$17.46	$20.82	$17.41	$13.03	$12.27	$12.54	$26.84
7	Customer	$/Cust/mo	$18.54	$15.62	$23.13	$47.07	$375.18	$439.66	$24.50	$1,225.62
	Cost Classifications at Uniform Current Return									
8	Energy		98,939,877	33,556,100	9,876,410	20,114,130	8,774,446	24,521,928	1,682,297	414,565
9	Demand		121,619,568	52,793,443	14,088,965	28,393,268	7,339,470	14,882,475	2,859,134	1,262,812
10	Customer		28,160,555	19,999,517	4,967,205	670,413	40,679	5,116	407,785	2,069,840
11	Total Uniform Current Cost		248,720,000	106,349,060	28,932,579	49,177,812	16,154,596	39,409,519	4,949,216	3,747,217
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.02940	$0.02980	$0.02980	$0.02974	$0.02924	$0.02849	$0.02980	$0.02980
13	Demand	$/kW/mo	$16.45	$19.18	$17.81	$16.39	$13.18	$11.50	$12.86	$30.47
14	Customer	$/Cust/mo	$19.00	$16.53	$20.81	$44.89	$376.66	$426.35	$24.91	$1,340.57
15	Revenue to Cost Ratio at Current Rates		1.00	0.94	1.12	1.05	0.99	1.04	0.98	0.91
	Cost Classifications at Proposed Return by Schedule									
16	Energy		101,745,475	33,300,372	10,651,891	20,999,090	8,935,553	25,742,689	1,709,204	406,677
17	Demand		129,723,846	51,611,403	17,384,713	32,156,285	7,691,075	16,693,907	3,005,406	1,181,057
18	Customer		28,643,678	19,727,226	5,735,396	739,625	41,372	5,404	421,389	1,973,266
19	Total Proposed Rate Revenue		260,113,000	104,639,000	33,772,000	53,895,000	16,668,000	42,442,000	5,136,000	3,561,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.03024	$0.02958	$0.03214	$0.03105	$0.02978	$0.02991	$0.03028	$0.02924
21	Demand	$/kW/mo	$17.55	$18.75	$21.98	$18.56	$13.81	$12.89	$13.52	$28.49
22	Customer	$/Cust/mo	$19.33	$16.30	$24.02	$49.52	$383.08	$450.36	$25.74	$1,278.02
	Cost Classifications at Uniform Requested Return									
23	Energy		101,178,013	34,315,179	10,099,826	20,569,136	8,972,935	25,076,643	1,720,353	423,943
24	Demand		129,574,068	56,303,142	15,038,521	30,328,109	7,772,653	15,705,622	3,066,004	1,360,017
25	Customer		29,360,919	20,807,922	5,188,529	706,000	41,533	5,247	427,026	2,184,662
26	Total Uniform Cost		260,113,000	111,426,243	30,326,875	51,603,244	16,787,120	40,787,511	5,213,383	3,968,622
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.03007	$0.03048	$0.03048	$0.03041	$0.02990	$0.02913	$0.03048	$0.03048
28	Demand	$/kW/mo	$17.53	$20.45	$19.01	$17.50	$13.96	$12.13	$13.79	$32.81
29	Customer	$/Cust/mo	$19.81	$17.19	$21.73	$47.27	$384.56	$437.26	$26.08	$1,414.94
30	Revenue to Cost Ratio at Proposed Rates		1.00	0.94	1.11	1.04	0.99	1.04	0.99	0.90
31	Current Revenue to Proposed Cost Ratio		0.96	0.89	1.07	1.00	0.96	1.01	0.93	0.86
32	Annual Consumption (mWh's)		3,364,879	1,125,882	331,376	676,398	300,092	860,777	56,445	13,910
33	Monthly Average NCP Demand (kW)		615,990	229,407	65,917	144,389	46,413	107,884	18,526	3,454
34	Monthly Average Number of Customers		123,495	100,853	19,895	1,245	9	1	1,364	129

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-12-08 Company Case | Customer Cost Analysis | Electric Utility | 10-10-12
AVU-E-10-01 Settlement Method | For the Twelve Months Ended June 30, 2012
Transmission By Demand 12 CP

Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return

	(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 CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Rate Base											
1	Services				45,622,000	37,307,157	7,359,316	450,806	0	0	504,721	0
2	Services Accum. Depr.				(16,622,000)	(13,592,556)	(2,681,306)	(164,247)	0	0	(183,891)	0
3	Total Services				29,000,000	23,714,602	4,678,010	286,558	0	0	320,830	0
4	Meters				20,634,000	11,920,038	6,231,158	1,759,439	35,061	6,159	682,146	0
5	Meters Accum. Depr.				(1,530,000)	(883,864)	(462,037)	(130,461)	(2,600)	(457)	(50,581)	0
6	Total Meters				19,104,000	11,036,173	5,769,121	1,628,977	32,461	5,702	631,565	0
7	Total Rate Base				48,104,000	34,750,775	10,447,131	1,915,536	32,461	5,702	952,395	0
8	Return on Rate Base @ 8.46%				4,069,603	2,939,919	883,828	162,054	2,746	482	80,573	0
9	Revenue Conversion Factor				0.63711	0.63711	0.63711	0.63711	0.63711	0.63711	0.63711	0.63711
10	Rate Base Revenue Requirement				6,387,629	4,614,482	1,387,253	254,360	4,310	757	126,467	0
	Expenses											
11	Services Depr Exp				1,255,000	1,026,270	202,445	12,401	0	0	13,884	0
12	Meters Depr Exp				1,533,000	885,597	462,943	130,717	2,605	458	50,680	0
13	Services Operations Exp				333,000	272,309	53,716	3,290	0	0	3,684	0
14	Meters Operating Exp				545,000	314,841	164,582	46,472	926	163	18,017	0
15	Meters Maintenance Exp				29,000	16,753	8,758	2,473	49	9	959	0
16	Meter Reading				430,000	336,412	66,362	4,152	16,671	1,852	4,551	0
17	Billing				2,945,000	2,402,643	473,952	29,652	2,865	318	32,505	3,065
18	Total Expenses				7,070,000	5,254,824	1,432,757	229,157	23,116	2,800	124,280	3,065
19	Revenue Conversion Factor				0.995010	0.995010	0.995010	0.995010	0.995010	0.995010	0.995010	0.995010
20	Expense Revenue Requirement				7,105,456	5,281,177	1,439,943	230,306	23,232	2,814	124,904	3,081
21	Total Meter, Service, Meter Reading, and				**13,493,085**	**9,895,660**	**2,827,195**	**484,666**	**27,542**	**3,571**	**251,370**	**3,081**
22	Total Customer Bills				1,481,940	1,210,233	238,734	14,936	108	12	16,373	1,544
23	Average Unit Cost per Month				$9.11	$8.18	$11.84	$32.45	$255.02	$297.57	$15.35	$2.00

Distribution Fixed Costs per Customer

	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 CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
24	Total Customer Related Cost	29,360,919	20,807,922	5,188,529	706,000	41,533	5,247	427,026	2,184,662
25	Customer Related Unit Cost per Month	$19.81	$17.19	$21.73	$47.27	$384.56	$437.26	$26.08	$1,414.94
26	Total Distribution Demand Related Cost	51,861,024	24,639,071	7,079,654	15,152,454	1,384,083	426,568	1,989,689	1,189,506
27	Dist Demand Related Unit Cost per Month	$35.00	$20.36	$29.65	$1,014.49	$12,815.59	$35,547.33	$121.52	$770.41
28	Total Distribution Unit Cost per Month	**$54.81**	**$37.55**	**$51.39**	**$1,061.76**	**$13,200.15**	**$35,984.59**	**$147.60**	**$2,185.34**

Avista Utilities

Cost of Service / Rate Design Workshop

September 18, 2012 IPUC Workshop

Settlement Stipulation (AVU-E-11-01)

10. Cost of Service. The Parties have agreed to exchange information and convene a public workshop, prior to the Company's next general rate case, with respect to the method of allocation of demand and energy among the customer classes such as the possible use of a revised peak credit method for classifying production costs, as well as consideration of the use of a 12 Coincident Peak (CP) (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs. This workshop will also address the merits of inclining or declining block rates for service schedules 11, 21, 25 and 31.

Workshop Topics

Item # 1 – Peak Credit Classification Method

Item # 2 – Allocation of Transmission Costs

Item # 3 – Merits of Inclining or Declining Block Rates

Item #1 - Peak Credit Classification Method

1. Review Previous Peak Credit Methodology
2. Discuss Avista Proposed Peak Credit Methodology
3. Why the change is preferable from Avista's viewpoint
4. Is the Proposed Peak Credit Methodology stable over time?

Item #1 - Peak Credit Classification Method (continued)

Prior Method

Avista's electric system resource costs were classified to energy and demand using a comparison of the replacement cost-per-kW of the Company's peaking units, to the replacement cost-per-kW of the Company's thermal and hydro generating facilities (separately).

- Created separate peak credit ratios applied to thermal plant and hydro plant.
- Transmission costs were assigned to energy and demand by a 50/50 weighting of the thermal and hydro peak credit ratios.
- Fuel and load dispatching expenses were classified entirely to energy.
- Peaking plant related costs were classified entirely to demand.

Item #1 - Peak Credit Classification Method (continued)

Proposed Method

Uses the system load factor to determine peak credit ratio.

- Stemmed from discussions at the February 2011 Cost of Service workshop.
- The Classification ratio is applied to all production costs.
- Calculation: One minus the load factor equals the demand percentage or peak credit ratio.

Net effect – slightly increases the overall production costs that are classified as demand-related.

- Using the prior method, approximately 32% of total production costs were classified as demand-related.
- Under the proposed load factor peak credit method, 36.4% of total production costs would be classified as demand-related.

Item #1 - Peak Credit Classification Method (continued)

Why does Avista view this methodology to be preferable?

- Tied to the Company's actual use of the system in the test year.
- Actual load factor represents current use of the system vs. historical replacement cost analysis which is based on vintage investments.
- Less complicated single ratio applied to all production costs vs. multiple ratios, weight dependent on each cost item's relationship to plant investment.
- Overall weighted demand/energy relationship stays the same when power costs are updated – not impacted by swings in the cost of fuel, unlike prior method.

Item #1 - Peak Credit Classification Method (continued)

Will the new methodology provide a "stable" demand/energy classification over time?

- Avista believes the proposed method will be more consistent over time versus the prior method.
- Proposed method demand proportion has varied from 34% to 39% in the last 5 years – a range of 5%.
- Prior method demand proportion has varied from 23% to 34% in the last 5 years – a range of 11% (driven in part by the cost of fuel)

Item #2 – Allocation of Transmission Costs

Historically, transmission costs were included in the production peak credit classification as they were considered extension of generation facilities

- Demand classified portion allocated to customer classes by 12 CP (average of the 12 monthly system coincident peak hours)

In the Settlement approved in AVU-E-10-01, the methodology was changed to now classify transmission costs as 100% demand.

- This is consistent with traditional NARUC approach.
- While the Settlement approved transmission classification as 100% demand, it kept the 12 CP allocation and required February 2011 workshop to discuss alternatives.
- In the AVU-E-11-01 general rate case, Avista proposed a weighted 12 CP allocation for transmission costs (stemming from February 2011 workshop discussions).

Item #2 – Allocation of Transmission Costs (continued)

Workshop Discussion – "consideration of the use of a 12 CP (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs".

1. 12 CP (average of the monthly system coincident peaks)
   - Captures relative contribution to demand throughout the year
   - Aligns with FERC Open Access transmission cost methodology
2. Weighted 12 CP - see Handout
   - Weighted by Relative Monthly System Peaks
   - Captures seasonal impacts of capacity utilization
3. 7 CP (average of 4 winter and 3 summer monthly system coincident peaks)
   - Assumes no transmission demand cost in shoulder months

Item #3 – Merits of Inclining or Declining Block Rates for Schedules 11, 21, 25 and 31

Present Base Rates

Schedule 1 (Residential)

Basic Charge	$5.25
First 600 kWh	7.848¢
Over 600 kWh	8.764¢

Schedule 11 (General Service)

Basic charge	$10.00
First 3,650 kWh	9.338¢
Over 3,650 kWh	6.958¢
Demand over 20 kW	$5.25

Schedule 21 (Large General Service)

First 250,000 kWh	6.039¢
Over 250,000 kWh	5.154¢
Demand 1st 50 kW	$350
Over 50 kW	$4.75

Schedule 25 (Extra Large General Service)

First 500,000 kWh	5.047¢
Over 500,000 kWh	4.275¢
Demand 1st 3,000 kVa	$12,500
Over 3,000 kVa	$4.50

Schedule 31 (Pumping)

Basic charge	$8.00
1st block	8.939¢
2nd block	8.939¢
3rd block	7.620¢

Support for Declining Block Rates – Schedules 11, 21, and 25:

Generally, the incremental fixed costs required to provide service to commercial and industrial customers do not increase proportionately with increasing energy usage.

- As most of the Company's fixed costs of service are recovered through the energy charges (and demand charges where applicable), larger use customers are generally less costly to serve than smaller use customers on an embedded cost per kWh basis, as fixed costs are spread over a larger base of usage.
- Within the Company's commercial and industrial schedules, there is also a substantial range of energy usage. Therefore, declining block rates for commercial and industrial customers generally reflect the cost of providing service within rate schedules, as well as across rate schedules.

Implementing rate structure changes can create potential customer bill volatility resulting from the new rate structure.

Merits for Inclining Block Rates:

- Sends a conservation price signal, and penalizes large users.
- Can promote fuel conversion – electric to natural gas fuel switching for residential customers.

NATURAL GAS COST OF SERVICE STUDY

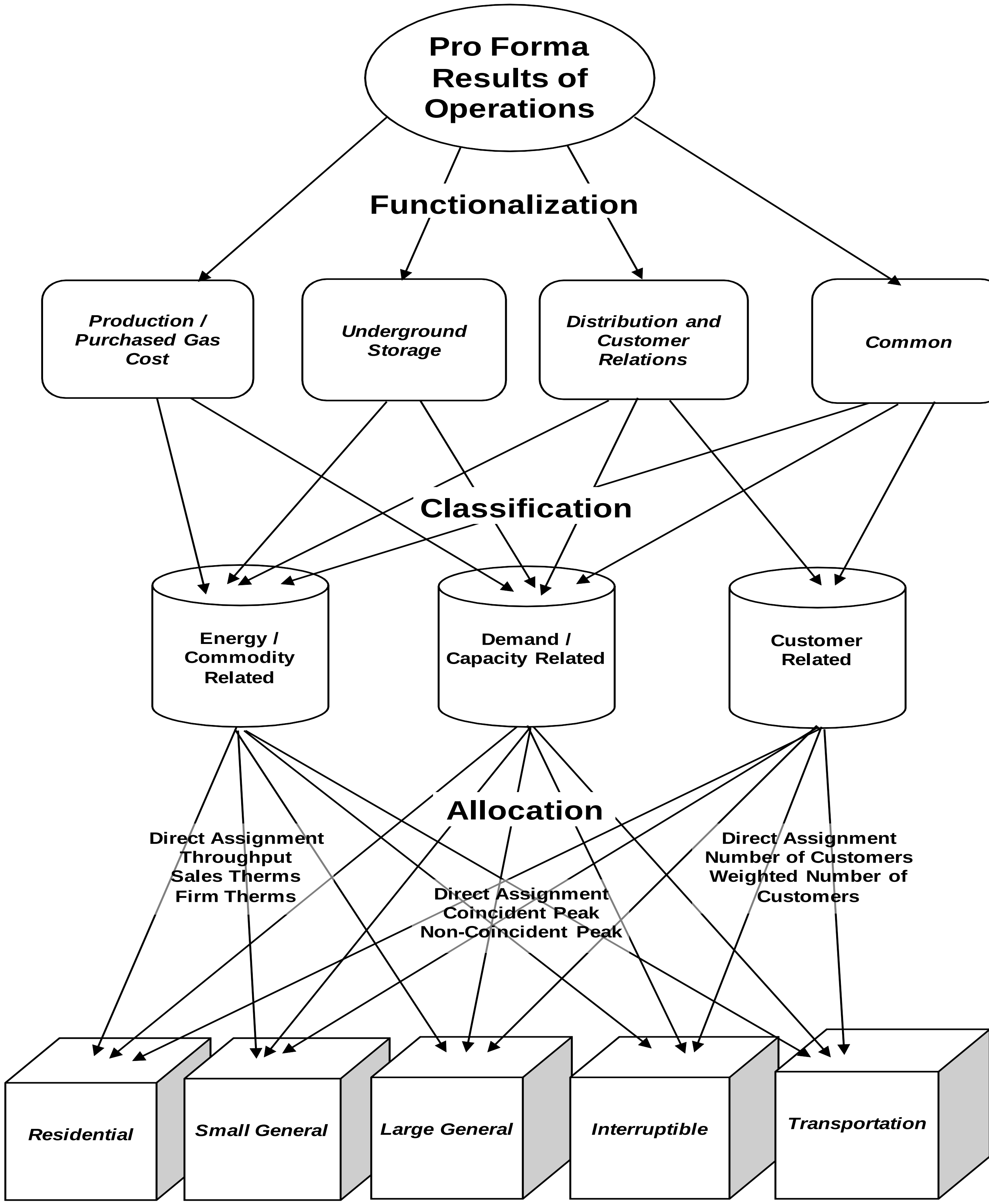
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. It indicates whether the revenue provided by customers recovers the cost to serve those customers. The study 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. This study includes 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 [1]

1 Customer classes shown in this flowchart are illustrative and may not match the Company's actual rate schedules.

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 to serve its retail customers. The natural gas costs included in the production function include the cost of gas purchased to serve sales customers, pipeline transportation to get it to our system, and expenses of the gas supply department.

The demand and commodity components of account 804 have been determined directly from the weighted average cost of gas (WACOG) approved in the most recent purchased gas adjustment (PGA) filing effective October 1, 2012. 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 34.40%. This proportion is classified as commodity related. The remaining 65.60% 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 any Demand Side Management amortization expense recorded in Account 908. Any demand side management investment costs and amortization expense included in base rates would be included with the distribution function and classified to demand and commodity by the peak and average ratio. At this point in time, the Company's demand side management investments in base rates have been fully amortized. All current demand side management costs are managed through the Schedule 191 Public Purpose Tariff Rider balancing account which is not included in this cost study.

Distribution Cost Allocation

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

Most customer related costs are allocated by the annualized number of customers billed during the test period. Meter investment costs are allocated using the number of customers weighted by the relative current cost of meters in service at December 31, 2011. Services investment costs are allocated using the number of customers weighted by the relative current cost of typical service installations. Industrial measuring and regulating equipment investment costs are allocated by number of turbine meters which effectively excludes small usage customers.

Administrative and General Costs

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

Special Contract Customer Revenue

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

Revenue Conversion Items

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

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

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

IPUC Case No. AVU-G-12-07 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

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

IPUC Case No. AVU-G-12-07 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

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

IPUC Case No. AVU-G-12-07 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

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

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Company Base Case | Cost of Service General Summary | Idaho Jurisdiction | 10-Oct-12
AVU-G-04-01 Method | For the Year Ended June 30, 2012

Line	Description (b)	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Plant In Service								
1	Production Plant								
2	Underground Storage Plant				10,832,000	7,986,151	2,606,033	40,792	199,024
3	Distribution Plant				160,940,000	134,562,866	24,897,046	381,443	1,098,645
4	Intangible Plant				2,880,000	2,391,170	460,142	7,063	21,625
5	General Plant				21,237,000	17,624,022	3,400,338	52,203	160,437
6	Total Plant In Service				195,889,000	162,564,209	31,363,559	481,502	1,479,731
	Accum Depreciation								
7	Production Plant								
8	Underground Storage Plant				(3,970,000)	(2,926,978)	(955,128)	(14,951)	(72,944)
9	Distribution Plant				(56,320,000)	(47,953,864)	(7,900,330)	(122,542)	(343,264)
10	Intangible Plant				(1,273,000)	(1,056,672)	(203,614)	(3,126)	(9,589)
11	General Plant				(7,261,000)	(6,025,711)	(1,162,587)	(17,848)	(54,854)
12	Total Accumulated Depreciation				(68,824,000)	(57,963,224)	(10,221,659)	(158,467)	(480,650)
13	Net Plant				127,065,000	104,600,985	21,141,900	323,035	999,081
14	Accumlulated Deferred FIT				(24,281,000)	(20,150,297)	(3,887,603)	(59,683)	(183,417)
15	Miscellaneous Rate Base				8,146,000	6,128,328	1,854,175	28,951	134,547
16	Total Rate Base				110,930,000	90,579,015	19,108,473	292,302	950,211
17	Revenue From Retail Rates				63,338,000	47,851,692	14,995,946	201,088	289,275
18	Other Operating Revenues				156,000	127,635	26,644	408	1,314
19	Total Revenues				63,494,000	47,979,327	15,022,590	201,496	290,588
	Operating Expenses								
20	Purchased Gas Costs				33,351,000	23,596,182	9,619,766	133,184	1,868
21	Underground Storage Expenses				275,000	202,750	66,161	1,036	5,053
22	Distribution Expenses				4,972,000	4,151,083	748,901	9,399	62,617
23	Customer Accounting Expenses				2,306,000	2,227,555	76,950	571	923
24	Customer Information Expenses				399,000	392,154	6,815	5	27
25	Sales Expenses				3,000	2,949	51	0	0
26	Admin & General Expenses				5,900,000	4,632,934	1,139,648	18,541	108,877
27	Total O&M Expenses				47,206,000	35,205,607	11,658,293	162,736	179,364
28	Taxes Other Than Income Taxes				1,024,000	854,789	159,613	2,447	7,152
29	Depreciation Expense								
30	Underground Storage Plant Depr				165,000	121,650	39,697	621	3,032
31	Distribution Plant Depreciation				4,076,000	3,415,369	623,992	9,436	27,203
32	General Plant Depreciation				1,974,000	1,638,170	316,065	4,852	14,913
33	Amortization of Intangible Plant				549,000	455,625	87,881	1,349	4,145
34	Total Depr & Amort Expense				6,764,000	5,630,814	1,067,634	16,259	49,292
35	Income Tax				2,021,000	1,394,722	611,619	4,408	10,251
36	Total Operating Expenses				57,015,000	43,085,932	13,497,159	185,849	246,060
37	Net Income				6,479,000	4,893,395	1,525,430	15,646	44,529
38	Rate of Return				5.84%	5.40%	7.98%	5.35%	4.69%
39	Return Ratio				1.00	0.92	1.37	0.92	0.80
40	Interest Expense				3,339,000	2,726,434	575,166	8,798	28,601

Line	Description (b)	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Functional Cost Components at Current Rates								
1	Production				33,521,417	23,716,754	9,668,921	133,864	1,878
2	Underground Storage				1,415,902	953,474	436,491	4,833	21,105
3	Distribution				19,044,897	15,749,532	3,127,224	35,691	132,449
4	Common				9,355,784	7,431,932	1,763,310	26,700	133,843
5	**Total Current Rate Revenue**				**63,338,000**	**47,851,692**	**14,995,946**	**201,088**	**289,275**
6	Exclude Cost of Gas w / Revenue Exp.				33,188,726	23,482,973	9,573,613	132,140	0
7	**Total Margin Revenue at Current Rates**				**30,149,274**	**24,368,719**	**5,422,333**	**68,948**	**289,275**
	Margin per Therm at Current Rates								
8	Production				$0.00424	$0.00436	$0.00436	$0.00436	$0.00073
9	Underground Storage				$0.01806	$0.01780	$0.01999	$0.01223	$0.00817
10	Distribution				$0.24295	$0.29399	$0.14319	$0.09036	$0.05125
11	Common				$0.11935	$0.13873	$0.08074	$0.06760	$0.05179
12	Total Current Margin Melded Rate per Therm				**$0.38460**	**$0.45488**	**$0.24827**	**$0.17456**	**$0.11193**
	Functional Cost Components at Uniform Current Return								
13	Production				33,521,417	23,716,754	9,668,921	133,864	1,878
14	Underground Storage				1,381,729	1,018,713	332,425	5,203	25,387
15	Distribution				19,072,494	16,256,713	2,634,104	37,400	144,277
16	Common				9,362,360	7,515,337	1,684,192	26,977	135,854
17	Total Uniform Current Cost				**63,338,000**	**48,507,517**	**14,319,643**	**203,444**	**307,397**
18	Exclude Cost of Gas w / Revenue Exp.				33,188,726	23,482,973	9,573,613	132,140	0
19	Total Uniform Current Margin				**30,149,274**	**25,024,544**	**4,746,030**	**71,303**	**307,397**
	Margin per Therm at Uniform Current Return								
20	Production				$0.00424	$0.00436	$0.00436	$0.00436	$0.00073
21	Underground Storage				$0.01763	$0.01902	$0.01522	$0.01317	$0.00982
22	Distribution				$0.24330	$0.30346	$0.12061	$0.09469	$0.05583
23	Common				$0.11943	$0.14029	$0.07711	$0.06830	$0.05257
24	Total Current Uniform Margin Melded Rate per				**$0.38460**	**$0.46712**	**$0.21731**	**$0.18052**	**$0.11894**
25	**Margin to Cost Ratio at Current Rates**				**1.00**	**0.97**	**1.14**	**0.97**	**0.94**
	Functional Cost Components at Proposed Rates								
26	Production				33,521,324	23,716,688	9,668,895	133,864	1,878
27	Underground Storage				1,920,688	1,319,496	564,632	6,688	29,872
28	Distribution				22,530,362	18,595,034	3,734,430	44,235	156,663
29	Common				9,926,626	7,899,855	1,860,727	28,083	137,961
30	**Total Proposed Rate Revenue**				**67,899,000**	**51,531,073**	**15,828,685**	**212,869**	**326,373**
31	Exclude Cost of Gas w / Revenue Exp.				33,188,634	23,482,908	9,573,586	132,140	0
32	**Total Margin Revenue at Proposed Rates**				**34,710,366**	**28,048,165**	**6,255,098**	**80,729**	**326,373**
	Margin per Therm at Proposed Rates								
33	Production				$0.00424	$0.00436	$0.00436	$0.00436	$0.00073
34	Underground Storage				$0.02450	$0.02463	$0.02585	$0.01693	$0.01156
35	Distribution				$0.28741	$0.34710	$0.17099	$0.11199	$0.06062
36	Common				$0.12663	$0.14746	$0.08520	$0.07110	$0.05338
37	Total Proposed Margin Melded Rate per Therm				**$0.44278**	**$0.52356**	**$0.28640**	**$0.20438**	**$0.12629**
	Functional Cost Components at Uniform Proposed Return								
38	Production				33,521,324	23,716,688	9,668,895	133,864	1,878
39	Underground Storage				1,884,238	1,389,199	453,322	7,096	34,620
40	Distribution				22,559,790	19,136,920	3,206,979	46,115	169,777
41	Common				9,933,648	7,988,967	1,776,102	28,388	140,191
42	Total Uniform Proposed Cost				**67,899,000**	**52,231,774**	**15,105,298**	**215,462**	**346,466**
43	Exclude Cost of Gas w / Revenue Exp.				33,188,634	23,482,908	9,573,586	132,140	0
44	Total Uniform Proposed Margin				**34,710,366**	**28,748,866**	**5,531,712**	**83,322**	**346,466**
	Margin per Therm at Uniform Proposed Return								
45	Production				$0.00424	$0.00436	$0.00436	$0.00436	$0.00073
46	Underground Storage				$0.02404	$0.02593	$0.02076	$0.01796	$0.01340
47	Distribution				$0.28778	$0.35722	$0.14684	$0.11675	$0.06569
48	Common				$0.12672	$0.14913	$0.08132	$0.07187	$0.05425
49	Total Proposed Uniform Margin Melded Rate pe				**$0.44278**	**$0.53664**	**$0.25328**	**$0.21095**	**$0.13406**
50	**Margin to Cost Ratio at Proposed Rates**				**1.00**	**0.98**	**1.13**	**0.97**	**0.94**
51	**Current Margin to Proposed Cost Ratio**				**0.87**	**0.85**	**0.98**	**0.83**	**0.83**

Sumcost | AVISTA UTILITIES | Natural Gas Utility
Company Base Case | Summary by Classification with Unit Cost Analysis | Idaho Jurisdiction | 10-Oct-12
AVU-G-04-01 Method | For the Year Ended June 30, 2012

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Cost by Classification at Current Return by Schedule								
1	Commodity				34,160,448	23,838,005	9,991,218	172,884	158,342
2	Demand				15,568,367	11,351,736	4,131,987	27,201	57,443
3	Customer				13,609,184	12,661,951	872,741	1,003	73,489
4	Total Current Rate Revenue				63,338,000	47,851,692	14,995,946	201,088	289,275
	Revenue per Therm at Current Rates								
5	Commodity				$0.43577	$0.44497	$0.45747	$0.43770	$0.06127
6	Demand				$0.19860	$0.21190	$0.18919	$0.06886	$0.02223
7	Customer				$0.17361	$0.23635	$0.03996	$0.00254	$0.02844
8	Total Revenue per Therm at Current Rates				$0.80797	$0.89322	$0.68662	$0.50910	$0.11193
	Cost per Unit at Current Rates								
9	Commodity Cost per Therm				$0.43577	$0.44497	$0.45747	$0.43770	$0.06127
10	Demand Cost per Peak Day Therms				$24.94	$23.55	$32.33	$12.37	$4.72
11	Customer Cost per Customer per Month				$15.09	$14.28	$56.65	$83.60	$1,224.82
	Cost by Classification at Uniform Current Return								
12	Commodity				34,031,219	24,006,790	9,682,672	174,093	167,665
13	Demand				15,512,746	11,562,903	3,858,320	28,310	63,214
14	Customer				13,794,035	12,937,824	778,652	1,041	76,518
15	Total Uniform Current Cost				63,338,000	48,507,517	14,319,643	203,444	307,397
	Cost per Therm at Current Return								
16	Commodity				$0.43412	$0.44812	$0.44334	$0.44076	$0.06488
17	Demand				$0.19789	$0.21584	$0.17666	$0.07167	$0.02446
18	Customer				$0.17596	$0.24150	$0.03565	$0.00264	$0.02961
19	Total Cost per Therm at Current Return				$0.80797	$0.90547	$0.65565	$0.51507	$0.11894
	Cost per Unit at Uniform Current Return								
20	Commodity Cost per Therm				$0.43412	$0.44812	$0.44334	$0.44076	$0.06488
21	Demand Cost per Peak Day Therms				$24.85	$23.99	$30.19	$12.87	$5.19
22	Customer Cost per Customer per Month				$15.29	$14.59	$50.55	$86.75	$1,275.30
23	**Revenue to Cost Ratio at Current Rates**				**1.00**	**0.99**	**1.05**	**0.99**	**0.94**
	Cost by Classification at Proposed Return by Schedule								
24	Commodity				35,512,391	24,784,909	10,371,125	178,930	177,427
25	Demand				17,107,424	12,536,458	4,468,962	32,747	69,257
26	Customer				15,279,184	14,209,705	988,597	1,193	79,690
27	Total Proposed Rate Revenue				67,899,000	51,531,073	15,828,685	212,869	326,373
	Revenue per Therm at Proposed Rates								
28	Commodity				$0.45301	$0.46265	$0.47486	$0.45300	$0.06865
29	Demand				$0.21823	$0.23401	$0.20462	$0.08291	$0.02680
30	Customer				$0.19491	$0.26525	$0.04526	$0.00302	$0.03084
31	Total Revenue per Therm at Proposed Rates				$0.86615	$0.96191	$0.72475	$0.53893	$0.12629
	Cost per Unit at Proposed Rates								
32	Commodity Cost per Therm				$0.45301	$0.46265	$0.47486	$0.45300	$0.06865
33	Demand Cost per Peak Day Therms				$27.40	$26.00	$34.97	$14.89	$5.69
34	Customer Cost per Customer per Month				$16.94	$16.03	$64.17	$99.38	$1,328.16
	Cost by Classification at Uniform Proposed Return								
35	Commodity				35,374,366	24,965,244	10,041,098	180,260	187,764
36	Demand				17,047,939	12,762,074	4,176,242	33,968	75,655
37	Customer				15,476,695	14,504,456	887,957	1,234	83,048
38	Total Uniform Proposed Cost				67,899,000	52,231,774	15,105,298	215,462	346,466
	Cost per Therm at Proposed Return								
39	Commodity				$0.45125	$0.46601	$0.45975	$0.45637	$0.07265
40	Demand				$0.21747	$0.23822	$0.19122	$0.08600	$0.02927
41	Customer				$0.19743	$0.27075	$0.04066	$0.00312	$0.03213
42	Total Cost per Therm at Proposed Return				$0.86615	$0.97499	$0.69162	$0.54549	$0.13406
	Cost per Unit at Uniform Proposed Return								
43	Commodity Cost per Therm				$0.45125	$0.46601	$0.45975	$0.45637	$0.07265
44	Demand Cost per Peak Day Therms				$27.31	$26.47	$32.68	$15.45	$6.21
45	Customer Cost per Customer per Month				$17.16	$16.36	$57.64	$102.85	$1,384.13
46	**Revenue to Cost Ratio at Proposed Rates**				**1.00**	**0.99**	**1.05**	**0.99**	**0.94**
47	**Current Revenue to Proposed Cost Ratio**				**0.93**	**0.92**	**0.99**	**0.93**	**0.83**

	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
						Residential	Large Firm	Interrupt	Transport
					System	Service	Service	Service	Service
Line	**Description**				Total	Sch 101	Sch 111	Sch 131	Sch 146
	Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return								
	Rate Base								
1	Services				49,451,000	$ 48,578,554	$ 844,170	$ 1,973	$ 26,303
2	Services Accum. Depr.				(22,558,000)	$ (22,160,017)	$ (385,084)	$ (900)	$ (11,999)
3	Total Services				26,893,000	26,418,537	459,086	1,073	14,305
4	Meters				21,321,000	$ 18,565,797	$ 2,658,436	$ 5,024	$ 91,743
5	Meters Accum. Depr.				(4,746,000)	$ (4,132,699)	$ (591,761)	$ (1,118)	$ (20,422)
6	Total Meters				16,575,000	14,433,099	2,066,675	3,906	71,321
7	Total Rate Base				43,468,000	40,851,635	2,525,761	4,978	85,625
8	Return on Rate Base @ 8.46%				3,677,393	3,456,048	213,679	421	7,244
9	Revenue Conversion Factor				0.63711	0.63711	0.63711	0.63711	0.63711
10	**Rate Base Revenue Requirement**				**5,771,990**	**5,424,571**	**335,389**	**661**	**11,370**
	Expenses								
11	Services Depr Exp				1,224,000	$ 1,202,405	$ 20,895	$ 49	$ 651
12	Meters Depr Exp				632,000	$ 550,330	$ 78,802	$ 149	$ 2,719
13	Services Maintenance Exp				418,000	$ 410,625	$ 7,136	$ 17	$ 222
14	Meters Maintenance Exp				415,000	$ 361,372	$ 51,745	$ 98	$ 1,786
15	Meter Reading				252,000	$ 247,676	$ 4,304	$ 3	$ 17
16	Billing				1,702,000	$ 1,672,795	$ 29,069	$ 23	$ 113
17	Total Expenses				4,643,000	4,445,204	191,950	338	5,509
18	Revenue Conversion Factor				0.995009	0.995009	0.995009	0.995009	0.995009
19	**Expense Revenue Requirement**				**4,666,289**	**4,467,501**	**192,913**	**340**	**5,536**
20	**Total Meter, Service, Meter Reading, and**				**10,438,280**	**9,892,072**	**528,301**	**1,001**	**16,906**
21	Total Customer Bills				901,972	886,495	15,405	12	60
22	**Average Unit Cost per Month**				**$11.57**	**$11.16**	**$34.29**	**$83.41**	**$281.77**
	Fixed Costs per Customer								
23	Total Customer Related Cost				15,476,695	14,504,456	887,957	1,234	83,048
24	Customer Related Unit Cost per Month				$17.16	$16.36	$57.64	$102.85	$1,384.13
25	Other Non-Gas Costs				19,233,671	14,244,410	4,643,754	82,088	263,419
26	Other Non-Gas Unit Cost per Month				$21.32	$16.07	$301.44	$6,840.63	$4,390.31
27	**Total Fixed Unit Cost per Month**				**$38.48**	**$32.43**	**$359.09**	**$6,943.48**	**$5,774.44**