BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET No's. UE-050482 and UG-050483

REBUTTAL TESTIMONY OF

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, employer and business address.

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

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes, I sponsored the electric and natural gas cost of service studies.

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

A. My testimony responds to cost of service issues discussed in the testimony of Public Counsel witnesses Mr. Lazar and Mr. Lott.

Q. Would you please summarize your rebuttal testimony?

A. Yes. Avista's electric cost of service study is not inconsistent with Commission policy, nor does it use "flawed data," as implied in Mr. Lazar's testimony. Furthermore, the similarity of the results produced by alternative studies supports the fact that the Company's cost of service study results are reasonable and should be used as a guide for revenue/rate spread.

Mr. Lott's discussion of the revenue credit factor calculation may lead the reader to believe the "common cost issue" represents a material change to the ERM. This is not true. The common costs are only indirectly related to the production function, and even if they were included in the factor, the impact on the ERM is not significant.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I have included Exhibit No. ___(TLK-7) which I will discuss later in my testimony.

II. ELECTRIC COST OF SERVICE METHODOLOGY

Q. Mr. Lazar discusses the Puget-specific peak credit assumptions at some length, and implies that having used different peak credit assumptions causes the cost of service results to be unreliable. Can you please summarize the issues involved here?

A. Yes. Production and transmission costs are segregated into demand and energy related components using a theoretical concept called peak credit. The Avista study computes and applies the peak credit theory differently from the process approved for Puget Sound Energy (then Puget Sound Power & Light) in 1992.

Mr. Lazar is concerned about two aspects of this issue: first, the proportion of production and transmission costs that are classified as demand-related and second, how these demand-related costs are allocated to the customer classes. Mr. Lazar's position is that the Puget process for both classification and allocation is the only acceptable way to treat these costs. However, the process used by Puget is specific to its system and it is more appropriate to utilize the Avista-specific application of the peak credit theory.

Q. Has this issue already been argued in a previous Avista case?

A. Yes. In Docket No. UE-991606 the Company filed a cost of service study utilizing Company-specific peak credit assumptions and definition of peak hours. These assumptions were specifically identified as items that made the methodology different from the 1992 Puget case resolution to which Mr. Lazar refers (Puget Method). The Commission accepted this deviation from the Puget Method in that case, stating: "The Commission agrees that the peak usage patterns of each unique company are appropriately used in that company's cost of service study." (Third Supplemental Order, Docket No. UE-991606 & UG-991607, page 108.)

Q. Why do you object to applying the Puget peak credit assumptions in the Company's cost of service study?

A. The assumptions built into the Puget peak credit calculation and the definition of the related coincident peak allocation factor were specific to Puget's Integrated Resource Plan in 1992. The two part comparisons they use and the two hundred hour peak are not relevant to Avista's system because the Company's use of peaking units is based upon economic dispatch of the entire resource stack. All of the Company resources should be represented in the comparison as well as all times of the year.

The process Avista has traditionally used incorporates <u>all</u> of the Company's production resources into the demand/energy comparisons. The Company's demand allocation using the average of twelve monthly peaks captures customer contribution to peak throughout the year.

Q. Mr. Lazar presents the results of an alternative study where the Company's study was revised to approximate the Puget Method. He remarks on the similarity of the results, implying that this is unexpected and indicative of some flaw in the data. Do you have any comments on his assessment of the impact of the difference between the Company method and the Puget Method?

A. Mr. Lazar has overlooked the fact that, in the Company method, not all production-related accounts receive the demand allocation percentages determined by the replacement cost analysis. Specifically, in the Company's application of peak credit, fuel accounts receive 100% energy allocation. The overall production and transmission costs in the

Company study included 28% demand allocation, whereas the study Mr. Lazar requested in order to emulate the Puget Method included 20% demand allocation for the same costs. Eight percent is not an overwhelming shift between demand and energy. Also both demand and energy allocations are related to usage so the factors are similar. Therefore, it is not surprising, nor does it indicate some inexplicable flaw in the data, when these two alternative scenarios produce similar cost relationships.

Q. Mr. Lazar seems to think that using Puget's 200 peak hour definition of the coincident peak allocation factor, instead of the average of the twelve monthly peaks the Company has traditionally used, would have materially changed the results of the alternate study. Do you agree with his assessment?

A. No. Due to the nature of the seasons in the Spokane area as compared to the milder temperatures experienced in the Seattle area, use of 200 peak hours on Avista's system will tend to have the <u>opposite</u> effect on demand allocation factors than Mr. Lazar may have seen on Puget's system. Rather than smooth the peaks for low load factor customers like the residential class, in Spokane a 200 hour peak will focus all the hours during extreme weather events. This will tend to increase the demand allocation to highly weather sensitive customer groups like the residential class while leaving high load factor customers with lower costs because their demand has remained the same while the total has increased. The average of the twelve monthly peaks, on the other hand, includes customer contribution to demand during extreme weather events as well as their contribution during more moderate times of the year.

Q. What were the results of the two study scenarios?

A. Table 1 below shows the rate of return and relative return ratio for each customer class from the Company's study as filed and the Puget Method study I provided to Mr. Lazar in response to his data request.

Table 1

Customer Class	As Filed Rate of Return	Puget Method Rate of Return	As Filed Return Ratio	Puget Method Return Ratio
Residential Service Sch 1	4.23%	4.43%	0.61	0.64
General Service Sch 11	13.14%	13.17%	1.91	1.92
Large General Service Sch 21	10.53%	10.22%	1.53	1.49
Extra Large Gen. Service Sch 25	4.56%	4.33%	0.66	0.63
Pumping Service Sch 31	7.25%	6.77%	1.06	0.99
Lighting Service Sch 41 - 49	7.86%	7.51%	1.14	1.09
Total WA Electric System	6.87%	6.87%	1.00	1.00

Q. What do you think the similarity in the results of the two study scenarios indicates?

A. When more than one cost of service scenario shows the same customer classes with under-recovery or over-recovery of the costs to serve them, it strengthens the value of the study results. In this case, even when you change a significant classification assumption, the study still supports the revenue/rate spread implications of the original study, and validates its use as a "guide" in resolving rate spread issues.

III. REVENUE CREDIT FACTOR

Q. How is the Company's cost of service study connected to the ERM deferral calculation?

A. Summary results of the cost of service study organized by function are used to determine the average production cost per kWh embedded in authorized retail rates. This value is multiplied by changes in Washington retail load to determine the retail revenue credit amount in the ERM calculation.

Q. What is the purpose of the revenue credit in the ERM calculation?

A. The purpose of the revenue credit in the ERM deferral calculation is to provide a volume variance component caused by retail loads. Part of the variability in power supply costs in the ERM is related to increased or decreased volumes of retail sales. The retail revenue credit provides an offset to actual net power supply costs associated with the change in retail consumption. The value of the retail revenue credit represents any additional production-related revenue received from retail customers.

Q. In his testimony Mr. Lott raises concerns related to the calculation of the retail revenue credit. Was a different methodology used in this case compared to Docket No. UE-011595?

A. As mentioned in my direct testimony Exhibit No. __(TLK-2) of this case, at page 1 paragraph 3: "In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category." This is the first time I have presented a functional summary in Washington with common costs in their own category. In Docket No. UE-011595 an allocation of common costs was in included in the retail revenue credit. In this case common costs have not been included in the retail revenue credit.

Q. If the common costs had been allocated to the production, transmission, and distribution categories in the same manner as shown in the functional summary from Docket No. UE-011595, what would the effect have been on the proposed revenue credit factor?

A. Exhibit No. ___(TLK-7) shows the functional component summary presented both with and without common costs in their own category. As is shown on line 36, column (f) the retail revenue credit factor including an allocation of common costs is $0.03739 per kWh. This is compared to a retail revenue credit factor of $0.03399 per kWh shown on line 26, column (f) that excludes an allocation of common costs. Mr. Johnson identified the $0.03399 per kWh figure as the Company's proposed revenue credit factor.

Q. If you compare the difference in these two factors using Mr. Lott's ERM examples on page 61 of his testimony, what is the impact of including indirect common costs in the factor?

A. In Mr. Lott's Year 1 example, the reduction in power cost from the revenue credit would be $3,400 more with common costs in the factor, therefore the deferral would be smaller. In Mr. Lott's Year 2 example, the increase in power costs from the revenue credit would be $6,800 more with common costs in the factor, therefore the deferral would be larger. The example calculations are shown in Table 2 below. As these examples illustrate, the effect of modifying the rate is symmetrical and does not represent a large monetary impact to the deferral calculation.

Table 2

Incremental Load	**$0.03739**	**$0.03399**	**Impact on Deferral**
ERM Year 1 Up 1,000,000 kWhs	-$37,390	-$33,990	Decrease $3,400
ERM Year 2 Down 2,000,000 kWhs	+$74,780	+$67,980	Increase $6,800

Q. What is the Company's position regarding indirect common costs in the revenue credit factor?

A. Common costs were presented as a separate functional component in this case because allocating them artificially inflates the perceived "cost" of production, transmission, and distribution embedded in the study. The Company prefers the revenue credit factor based on direct production costs excluding an allocation of common costs, however, this item is not considered a material issue.

Q. If the cost of service study were re-run to reflect results of operations and proposed revenues associated with the Settlement Agreement, what is the retail revenue credit factor produced by those assumptions?

A. The retail revenue credit factor associated with the proposed Settlement Agreement is $0.03302 per kWh excluding an allocation of common costs.

IV. CONCLUSION

Q. Do you have any closing comments on the cost of service issues raised by Public Counsel witnesses?

A. The electric cost of service study is not "flawed" as Mr. Lazar implied and the similarity of the study results using alternative assumptions supports the rate spread guidance provided by the Company study.

Whether or not common costs are included in the revenue credit factor used in the ERM calculation as Mr. Lott proposes is not a material issue, but the Company's preference is to exclude an allocation of common costs.

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

A. Yes, it does.

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DOCKET NO. UE-050482

EXHIBIT NO. ___(TLK-7)

TARA L. KNOX

REPRESENTING AVISTA CORPORATION

Sumcost
Scenario: Company Base Case
UE-011595 Methodology

AVISTA UTILITIES
Revenue by Functional Component Summary
For the Year Ended December 31, 2004

Washington Jurisdiction
Electric Utility

03-10-01

	(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) Pumping Service Sch 31-32	(l) Street & Area Lights Sch 41-49
	Revenue From Current Rates by Functional Components								
1	Production		158,404,218	64,333,039	14,188,033	51,217,343	24,387,318	3,524,170	754,316
2	Transmission		28,875,469	10,901,502	3,019,492	10,160,933	4,031,315	630,584	131,644
3	Distribution		64,535,770	29,821,968	8,977,479	19,200,497	2,555,780	1,232,661	2,747,385
4	Common		34,335,543	17,007,491	3,235,996	8,888,227	3,864,588	681,586	657,655
5	Total Current Rate Revenue		286,151,000	122,064,000	29,421,000	89,467,000	34,839,000	6,069,000	4,291,000
	Expressed as $/kWh								
6	Production		$0.03073	$0.02917	$0.03820	$0.03367	$0.02684	$0.02934	$0.02757
7	Transmission		$0.00560	$0.00494	$0.00813	$0.00668	$0.00444	$0.00525	$0.00481
8	Distribution		$0.01252	$0.01352	$0.02417	$0.01262	$0.00281	$0.01026	$0.10041
9	Common		$0.00666	$0.00771	$0.00871	$0.00584	$0.00425	$0.00567	$0.02404
10	Total Current Melded Rates		$0.05552	$0.05535	$0.07922	$0.05881	$0.03834	$0.05052	$0.15682
	Revenue From Current Rates by Functional Components with Common Costs Allocated to Production, Transmission, and Distribution								
11	Production		175,465,577	72,033,821	15,517,122	56,117,470	27,096,331	3,877,692	823,141
12	Transmission		32,031,762	12,287,497	3,272,284	11,096,222	4,532,661	697,831	145,266
13	Distribution		78,653,661	37,742,681	10,631,594	22,253,307	3,210,008	1,493,477	3,322,594
14	Common		0	0	0	0	0	0	0
15	Total Current Rate Revenue		286,151,000	122,064,000	29,421,000	89,467,000	34,839,000	6,069,000	4,291,000
	Expressed as $/kWh								
16	Production		$0.03404	$0.03266	$0.04178	$0.03689	$0.02982	$0.03228	$0.03008
17	Transmission		$0.00621	$0.00557	$0.00881	$0.00729	$0.00499	$0.00581	$0.00531
18	Distribution		$0.01526	$0.01711	$0.02863	$0.01463	$0.00353	$0.01243	$0.12143
19	Common		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
20	Total Current Melded Rates		$0.05552	$0.05535	$0.07922	$0.05881	$0.03834	$0.05052	$0.15682
	Revenue From Proposed Rates by Functional Components								
21	Production		175,176,296	72,296,238	15,301,354	55,664,678	27,215,755	3,874,893	823,378
22	Transmission		34,747,285	13,687,515	3,407,692	11,718,364	5,023,870	753,809	156,035
23	Distribution		76,582,931	36,219,720	10,033,359	22,467,434	3,261,148	1,472,952	3,128,318
24	Common		35,477,489	17,613,035	3,328,378	9,161,757	3,991,468	703,583	679,269
25	Total Proposed Rate Revenue		321,984,000	139,816,507	32,070,783	99,012,233	39,492,240	6,805,236	4,787,000
	Expressed as $/kWh								
26	Production		$0.03399	$0.03278	$0.04120	$0.03659	$0.02995	$0.03226	$0.03009
27	Transmission		$0.00674	$0.00621	$0.00918	$0.00770	$0.00553	$0.00628	$0.00570
28	Distribution		$0.01486	$0.01642	$0.02702	$0.01477	$0.00359	$0.01226	$0.11433
29	Common		$0.00688	$0.00799	$0.00896	$0.00602	$0.00439	$0.00586	$0.02483
30	Total Proposed Melded Rates		$0.06247	$0.06340	$0.08635	$0.06509	$0.04347	$0.05665	$0.17495
	Revenue From Proposed Rates by Functional Components with Common Costs Allocated to Production, Transmission, and Distribution								
31	Production		192,710,400	80,220,417	16,662,566	60,691,010	30,004,034	4,238,252	894,120
32	Transmission		38,038,868	15,137,276	3,669,572	12,689,834	5,548,061	823,903	170,221
33	Distribution		91,234,732	44,458,814	11,738,646	25,631,389	3,940,145	1,743,080	3,722,658
34	Common		0	0	0	0	0	0	0
35	Total Proposed Rate Revenue		321,984,000	139,816,507	32,070,783	99,012,233	39,492,240	6,805,236	4,787,000
	Expressed as $/kWh								
36	Production		$0.03739	$0.03637	$0.04487	$0.03990	$0.03302	$0.03528	$0.03268
37	Transmission		$0.00738	$0.00686	$0.00988	$0.00834	$0.00611	$0.00686	$0.00622
38	Distribution		$0.01770	$0.02016	$0.03161	$0.01685	$0.00434	$0.01451	$0.13605
39	Common		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
40	Total Proposed Melded Rates		$0.06247	$0.06340	$0.08635	$0.06509	$0.04347	$0.05665	$0.17495