

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DIRECT TESTIMONY OF

MARCUS J. GARBARINO

REPRESENTING AVISTA CORPORATION

1 **I. INTRODUCTION**

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

4 A. My name is Marcus J. Garbarino, and my business address is 1411 East  
5 Mission Avenue, Spokane, Washington. I am employed as Manager of Regulatory Affairs in  
6 the Regulatory Affairs Department.

7 **Q. What is your educational background and professional experience?**

8 A. I am a 2008 graduate of Eastern Washington University with a Bachelor of  
9 Arts degree in Business Administration, majoring in Accounting, and became a Certified  
10 Public Accountant in May 2011. After spending four years in the public accounting sector, I  
11 joined Avista in April 2012 as a Resource Accounting Analyst. In July 2014, I moved to the  
12 Company's Internal Audit Department as a Senior Internal Auditor until joining the  
13 Regulatory Affairs group in October 2020 as Manager of Regulatory Affairs. My primary  
14 responsibilities include electric cost of service, customer usage and revenue analysis, and  
15 preparing annual Purchased Gas Adjustment filings for all jurisdictions, amongst other things.

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

17 A. My testimony and exhibit present the Company's electric revenue  
18 normalization adjustments and the electric cost of service study prepared for this filing. The  
19 results of this study were provided to Company witness Mr. Miller and were used to inform  
20 the spread of the proposed increase by service schedule. Company witness Mr. Anderson  
21 testifies regarding the natural gas cost of service study and the natural gas revenue  
22 normalization adjustment.

23 A table of contents for my testimony is as follows:

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12 **Q. Are you sponsoring any exhibits in this case?**

13 A. Yes. I am sponsoring Exh. MJG-2 which presents the electric cost of service  
14 study results in the form of the electric cost of service template provided by the Commission  
15 in accordance with WAC 480-85-040(1). This exhibit was prepared by me and consists of  
16 summaries of information derived from the Electric Cost of Service Study.

17

18 **II. SUMMARY**

19 **Q. Would you please briefly summarize your testimony related to the electric  
20 cost of service study.**

21 A. Yes. I believe the Base Case cost of service study presented in this case is a  
22 fair representation of the costs to serve each customer group. The Base Case study shows  
23 Residential Service (Schedule 01), General Service Optional Electric Vehicle (Schedule 13),  
24 and Large General Service Optional Electric Vehicle (Schedule 23) below parity as these  
25 classes provide significantly less than the overall rate of return under present rates. All other  
26 classes (General Service (Schedules 11/12), Large General Service (Schedules 21/22), Extra  
27 Large General Service (Schedule 25), Pumping Schedules (30/31/32) and Street and Area

1 Lighting Service Schedules (41 – 48) are over parity as they provide more than the overall  
 2 rate of return under present rates. Table No. 1 below shows the rate of return and the  
 3 relationship of the customer class return to the overall return (relative return ratio) at present  
 4 rates as well as the revenue-to-cost parity ratio at present rates for each rate schedule:

5 **Table No. 1 – Relative Rates of Return at Present Rates, Return Ratio and Parity Ratio**

<u>Customer Class</u>	<u>Rate of Return</u>	<u>Return Ratio</u>	<u>Parity Ratio</u>
Residential Service Schedules 01/02	2.21%	0.43	0.86
General Service Schedule 11/12	8.90%	1.74	1.18
General Service Optional EV Charging Schedule 13	-7.62%	-1.50	0.27
Large General Service Schedules 21/22	9.43%	1.85	1.21
Large General Service Optional EV Charging Schedule 23	-9.56%	-1.87	0.14
Extra Large General Service Schedule 25	9.47%	1.86	1.20
Pumping Service Schedules 30/31/32	6.12%	1.20	1.05
Lighting Service Schedule 41 - 48	<u>6.95%</u>	<u>1.36</u>	<u>1.06</u>
Total Washington Electric System	<u>5.10%</u>	<u>1.00</u>	<u>1.00</u>

17  
 18  
 19 Notably, the Residential Service (Schedule 01), General Service (Schedules 11/12), General  
 20 Service Optional Electric Vehicle (Schedule 13), Large General Service (Schedules 21/22),  
 21 Large General Service Optional Electric Vehicle (Schedule 23), and Extra Large General  
 22 Service (Schedule 25) are considerably further from unity in the cost study than the other rate  
 23 schedules.<sup>1</sup>

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<sup>1</sup> General Service Optional Electric Vehicle (Schedule 13) and Large General Service Optional Electric Vehicle (Schedule 23) were approved in Docket UE-210182 with an effective date of April 26, 2021. Given the limited number of customers taking service on these schedules, and the varying levels of usage for some customers throughout the full test year, the cost of service study results for these schedules appear irregular. The Company expects these schedules to mature over time as EV technology continues to evolve and customers usage becomes more consistent, which the Company believes may yield more meaningful cost of service study results in future cost of service studies.

1 **III. ELECTRIC REVENUE NORMALIZATION**

2 **Q. Would you please describe the electric revenue normalization adjustments**  
 3 **included in Company witness Ms. Schultz's Electric Pro Forma Study?**

4 A. Yes. Similar to the natural gas revenue normalization adjustment, sponsored  
 5 by Mr. Anderson, there are three separate adjustments that normalize revenue as part of the  
 6 electric revenue normalization adjustment:

7 **1. Weather Normalization:** Column 2.10 of Ms. Schultz's Exh. KJS-2, page 7 is a  
 8 Commission Basis weather normalization restating adjustment. Revenues for this  
 9 adjustment are based on rates that were in effect during the July 2022 through June  
 10 2023 test period, and kWh sales and revenues have been adjusted to reflect normal  
 11 weather conditions. The weather-related deferred revenues associated with the  
 12 Company's electric Decoupling Mechanism are removed in this adjustment, as kWh  
 13 sales and revenues have been normalized to reflect normal weather conditions.

14  
 15 **2. Eliminate Adder Schedules:** In addition to the weather normalization adjustment,  
 16 Ms. Schultz's study also includes an Eliminate Adder Schedules restating adjustment  
 17 in column 2.11 of Exh. KJS-2, page 7, which removes the impact of adder schedule  
 18 revenues and related expenses during the July 2022 through June 2023 test period.  
 19 Decoupling contra-revenues recorded in the test period associated with financial  
 20 reporting revenue recognition limits on deferred revenue mechanisms are also  
 21 eliminated in this adjustment for Commission Basis reporting purposes.<sup>2</sup>

22  
 23 **3. Pro Forma Revenue:** The Pro Forma Revenue Normalization Adjustment in  
 24 column 3.01 of Exh. KJS-2, page 9, adjusts July 2022 through June 2023 test period  
 25 customers and usage for any known and measurable (pro forma) changes. In addition,  
 26 the adjustment re-prices billed, unbilled, and weather-adjusted usage at the base tariff  
 27 rates approved for the test period, as if the December 21, 2023, base tariff rates were  
 28 in effect for the full 12-months of the test period.<sup>3</sup>

29  
 30 **Weather Normalization**

31 **Q. Please begin with the first revenue normalizing adjustment. What is the**  
 32 **Commission Basis weather normalization adjustment?**

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<sup>2</sup> There were no decoupling contra-revenues recorded during the test period.

<sup>3</sup> Dockets UE-220053 et. al.

1           A.     Weather normalization is a required element of Commission Basis reporting  
2 pursuant to WAC 480-100-257. The intent of this adjustment is for Commission Basis  
3 adjusted revenues (and power supply costs) to reflect operations under normal temperature  
4 conditions during the reporting period.

5           **Q.     Please briefly summarize the electric weather normalization process.**

6           A.     The Company's electric weather normalization adjustment calculates the  
7 change in kWh usage required to adjust actual loads during the test period to the amount  
8 expected if weather had been normal. This adjustment incorporates the effect of both heating  
9 and cooling on weather-sensitive customer groups. The weather adjustment is developed from  
10 an analysis of ten years (January 2013 through December 2022) of calendarized usage-per-  
11 customer and calendar period heating and cooling degree-day data. The resulting monthly  
12 weather sensitivity factors (use-per-customer-per-heating-degree day and use-per-customer-  
13 per-cooling-degree day) are applied to the difference between normal heating/cooling degree-  
14 days and monthly test year observed heating/cooling degree-days. This calculation produces  
15 the change in kWh usage required to adjust actual test period loads to the amount expected if  
16 weather had been normal.

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

19           A.     The methodology is generally consistent, but in this case the Company is proposing  
20 to make two changes to the weather normalization methodology. First, the Company proposes to  
21 change the definition of "normal" from a 30-year to a 20-year rolling average. Second, the  
22 Company proposes to adjust its non-degree day seasonal regression factors from seasonal factors  
23 to monthly factors. These two changes are discussed in detail in Company witness Dr. Forsyth's

1 testimony (Exh GDF-1T).

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

4 A. Yes, with the inclusion of the two changes noted above this methodology was  
5 included in the Company's most recent general rate case filing. Both changes were agreed to  
6 by the Parties as part of a broad Settlement Stipulation that was approved by the Idaho Public  
7 Utilities Commission.

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

10 A. Normal heating and cooling degree days are based on a rolling 20-year average  
11 of heating and cooling degree-days reported for each month by the National Weather Service  
12 for the Spokane International Airport weather station. Each year the normal values are  
13 adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting  
14 the most recent information available at the end of each calendar year. The calculation  
15 includes the 20-year period from 2003 through 2022.

16 **Q. What was the change in kWhs resulting from weather normalization for**  
17 **the 12-months ended June 2023 test period?**

18 A. Weather was warmer than normal during the July 2022 through June 2023  
19 period. Since electric usage is impacted by both heating and cooling, weather normalization  
20 required an increase to usage for warm weather during the winter/fall months and a reduction  
21 to usage for hot weather during the summer months. Overall, the adjustment to normal  
22 required an increase of 134 heating degree-days and the reduction of 319 cooling degree-days  
23 during the test period. The annual total adjustment to Washington electric sales volumes was

1 a reduction of 112,314,908 kWhs, which is approximately 1.9% of billed usage.

2 **Q. What was the impact of this adjustment on restated results of operations?**

3 A. The Commission Basis weather normalization adjustment decreased total  
4 electric revenues by (\$10,306,000). The combined effect of netting the decrease to revenue  
5 against the decoupling revenue offset of \$8,423,000, resulted in net weather adjustment  
6 revenue of (\$1,883,000).<sup>4</sup> After an offsetting adjustment for revenue-related expenses and  
7 taxes, the weather normalization adjustment produced a decrease to net operating income of  
8 (\$1,101,000), as shown below:

9 **Table No. 2: - Weather Normalization Adjustment Summary**

10	General Business Revenue (Sales)	(\$10,306,000)
11	Other Revenue (Decoupling Deferred)	\$8,423,000
12	Total Revenue (Net Adjustment)	<u>(\$1,883,000)</u>
13	Less: Revenue Related Expenses	\$489,000
14	Less: Income Tax Expense	\$293,000
15	Net Operating Income	<u>(\$1,101,000)</u>

16  
17  
18 The cost of the weather-related load change is reflected in the “Authorized Power Supply”  
19 adjustment in column 2.19 (page 8, Exh. KJS-2). This power supply adjustment also captures  
20 the test period load difference from the retail load included in the Energy Recovery  
21 Mechanism (ERM) base approved by Docket UE-200900 from July 1, 2022 through  
22 December 20, 2022 and Docket UE-220053 from December 21, 2022 through June 30, 2023.  
23 Both the difference from authorized to actual loads for the 12-months ended June 30, 2023  
24 and the weather normalization adjustment to loads are multiplied by the ERM Retail Revenue  
25 Adjustment Rate and then added to the ERM base costs. This process matches power supply

<sup>4</sup> The Decoupling Mechanism went into effect January 1, 2015.



1 costs with the power supply revenue-per-kWh embedded in present rates thereby maintaining  
2 the present authorized ERM base for Commission Basis results. For pro forma power supply  
3 cost determinations used in the “Pro Forma Power Supply” adjustment column 3.00P (page  
4 9, Exh. KJS-2), the monthly system kWh weather adjustment values were provided to  
5 Company witness Mr. Kalich to incorporate into the 12-months ended June 30, 2023  
6 normalized historical test period loads.

7

8 **Eliminate Adder Schedules**

9 **Q. Moving on to the second revenue normalizing adjustment, what is the**  
10 **purpose of the Eliminate Adder Schedules restating adjustment?**

11 A. The Eliminate Adder Schedules adjustment removes both the revenues and  
12 expenses associated with all adder schedule rates not accounted for in other adjustments.  
13 These items are recovered/rebated by separate tariffs and therefore are not part of base rates.  
14 The items eliminated from the test period include: Schedule 59 Residential Exchange credit,  
15 Schedule 75 Decoupling rate adjustment, Schedule 76 Customer Tax Credit, Schedule 78  
16 Residual Tax Customer Credit, Schedule 88 Wildfire Resiliency, Schedule 89 Fixed-Income  
17 Senior and Disabled Residential Service Discount rate adjustment, Schedule 91 Demand Side  
18 Management rate adjustment, Schedule 92, Low Income Rate Assistance Program rate  
19 adjustment, Schedule 95 Optional Renewable Power rate, and the unbilled portion of Schedule  
20 98 Renewable Energy Credit Revenue Mechanism credit.

21 **Q. What was the impact of the Eliminate Adder Schedule adjustment on**  
22 **restated results of operations?**

23 A. The Eliminate Adder Schedule adjustment results in a nearly equal and

1 offsetting reduction to both revenue and expense unless contra-decoupling entries were  
2 recorded in the test period. As noted in footnote 2 above, there were no decoupling contra-  
3 revenues recorded during the test period, and the resulting adjustment was an increase to net  
4 income of \$2,000.

5 The billed portion of Schedules 93 and 98 is eliminated in the Eliminate WA Power  
6 Cost Deferral adjustment 2.16 on page 8 of Exh. KJS-2, and Schedule 58 Municipal Tax  
7 Adjustment is eliminated in the Eliminate B&O Taxes adjustment 2.01 on page 6 of Exh. KJS-  
8 2. After these adjustments the Restated Total General Business revenue (column R-Total on  
9 page 8 of Exh. KJS-2) represents weather normalized base rate revenue received during the  
10 12-months ended June 30, 2023 test period (including decoupling deferred revenue not  
11 explained by weather).

12

13 **Pro Forma Revenue**

14 **Q. Please describe the purpose of the third revenue normalizing adjustment,**  
15 **the Pro Forma Revenue Normalization adjustment.**

16 A. The purpose of the Pro Forma Revenue Normalization adjustment (3.01) is to  
17 restate revenue on a forward-looking basis. This is accomplished by re-pricing test period  
18 normalized billing determinants (including unbilled and weather adjustments, as well as any  
19 known and measurable changes to the test period loads and customers) to reflect revenues for  
20 the July 2022 through June 2023 test period, as if the base tariff rates approved in Dockets  
21 UE-220053 et. al. effective December 21, 2023, had been in effect for the full 12 months of

1 the test period.<sup>5</sup>

2 **Q. What is the impact of the Pro Forma Revenue Normalization adjustment?**

3 A. The Pro Forma Revenue Normalization adjustment increases general business  
4 revenue by \$30,477,000. The combined effect of the increase to revenue from rates with  
5 elimination of the restated decoupling deferred revenue of \$2,814,000 resulted in a total pro  
6 forma revenue adjustment increase of \$33,291,000. After an offset for revenue-related  
7 expenses and taxes, net operating income increased \$25,156,000, as shown below and in  
8 column 3.01 on page 9 of Exh. KJS-2.

9 **Table No. 3 – Summarize Revenue Normalization Adjustment**

10	General Business Revenue (Sales)	\$30,477,000
	Other Revenue (Eliminate Decoupling Deferred)	<u>\$2,814,000</u>
11	Total Revenue (Net Adjustment)	\$33,291,000
	Less: Revenue Related Expenses	\$1,448,000
12	Less: Income Tax Expense	<u>\$6,687,000</u>
13	Net Operating Income	\$25,156,000

14 **IV. ELECTRIC COST OF SERVICE**

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

16 A. An electric cost of service study is an engineering-economic study, which  
17 separates the revenue, expenses, and rate base associated with providing electric service to  
18 designated groups of customers. The groups are made up of customers with similar load  
19 characteristics and facilities requirements. Costs are assigned or allocated to each group based  
20 on (among other things) test period load and facilities requirements, resulting in an evaluation  
21 of the cost of the service provided to each group. The rate of return by customer group

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<sup>5</sup> The Pro Forma Normalized Revenue does not include any pro formed decoupling deferred revenue. As in prior cases, the decoupling base will be updated in the Company's Compliance Filing with the rates approved for this case based on the same usage and customers used to determine revenue from present rates in this adjustment.

1 indicates whether the revenue provided by the customers in each group recovers the cost to  
2 serve those customers. The study results are used as a guide in determining the appropriate  
3 rate spread among the groups of customers.

4 **Q. What is the basis for the electric cost of service study provided in this case?**

5 A. The electric cost of service study provided by the Company as Exh. MJG-2 is  
6 based on the 12-months ended June 2023 test period pro forma results of operations for Rate  
7 Year 1 presented by Ms. Schultz as Exh. KJS-2.

8 **Q. Are Cost of Service studies a required component of general rate case**  
9 **filings?**

10 A. Yes. WAC 480-07-510(6), which discusses cost studies in general rate  
11 proceeding filings, was amended by General Order R-599 on July 7, 2020 to state that a  
12 utility's initial general rate case filing must include a cost of service study that complies with  
13 the new chapter WAC 480-85. The Company believes the electric cost of service study  
14 presented in this filing meets all the requirements set forth in WAC chapter 480-85.

15 **Q. Please identify cost of service studies conducted in the last five years for**  
16 **the company?**

17 A. The electric cost of service studies provided in the last five years can be found  
18 in Dockets UE-190334, UE-200900, and UE-220053.

19

20 **Methodology**

21 **Q. Does the Electric Base Case cost of service study utilize the same**  
22 **methodology from the Company's last electric case in Washington?**

23 A. Yes, the Base Case cost of service study was prepared using the same

1 methodology used in our previous rate case, which complies with the methodology described  
2 in WAC 480-85-060.

3 **Q. Please explain the cost of service study presented in Exh. MJG-2?**

4 A. Exh. MJG-2 presents the results of the cost of service study in the form of the  
5 electric cost of service template available from the Commission in compliance with WAC  
6 480-85-040(1). Electronically, the template consists of five workbook tabs that are presented  
7 as separate sections in this exhibit. Section A is the Revenue Requirement Cross-Reference  
8 which shows Ms. Schultz revenue requirement development for Rate Year 1 (Exh. KJS-2),  
9 expressed at the FERC Account level to facilitate assignment of costs to customer rate classes  
10 in the study. Section B presents the FERC Account level cost of service results for all  
11 customer rate classes. Section C shows the allocation factors used to assign each type of cost  
12 to the customer rate classes. Section D is a summary of the revenue requirement adjustments  
13 shown in Section A and is comparable to page 15 of Ms. Schultz Exh. KJS-2. Finally, Section  
14 E is a high-level summary of the cost of service results showing the Parity Ratios at present  
15 rates and Revenue-to-Cost Ratios at proposed rates. The fully functional Excel model  
16 supporting this exhibit that calculates the cost of service results, along with supporting  
17 schedules, have been included in their entirety electronically and hard copy in the workpapers  
18 accompanying this case.

19 **Q. How are generation costs treated in this study?**

20 A. In this study, generation costs (production plant related rate base and expenses  
21 including operation and maintenance, depreciation and taxes) have been classified as energy  
22 or demand-related based on a renewable future peak credit ratio, with net power costs  
23 considered 100% energy. The demand-related portions were allocated to customer rate classes

1 based on the average of 12 system coincident peaks determined from power supply native  
2 load, excluding renewable generation. The energy-related portions were allocated to customer  
3 rate classes based on annual energy usage at the point of generation.

4 The renewable future peak credit method compares the cost of battery storage  
5 (demand) to wind turbine (energy) derived from the Company's 2023 Electric IRP, at 2025  
6 cost assumptions. This analysis resulted in 54.3% demand and 45.7% energy peak credit  
7 allocation (proportions exclusive of energy-related net power costs). Use of the renewable  
8 future peak credit ratio is in accordance with Commission rules which were adopted with an  
9 eye to the future where renewable resources provide energy, but reliable capacity is going to  
10 be problematic. The treatment is consistent with the methodology presented in Dockets UE-  
11 220053 et. al.

12 **Q. How are transmission costs treated in this study?**

13 A. All transmission costs (except Transmission of Electricity by Others and  
14 revenue from Transmission of Electricity for Others which are part of net power costs included  
15 in the Energy Recovery Mechanism) are considered demand-related and allocated to customer  
16 rate classes by the average of 12 system coincident peaks. The treatment is consistent with the  
17 methodology presented in Dockets UE-220053 et. al.

18 **Q. How are distribution costs treated in this study?**

19 A. This study follows methodology set forth in WAC 480-85-060 utilizing  
20 allocation factors for the customer rate classes that are not directly assigned, and directly  
21 assigning distribution substations, poles, conduit, and wires to the Extra Large General  
22 Service schedule 25 based on the load ratio share of substations they are fed from. For  
23 distribution substations, this study allocates these classes by the average of the relative share

1 of the summer distribution system coincident peak and the relative share of the winter  
2 distribution system coincident peak. Distribution line transformer costs are allocated to  
3 customers who receive power at secondary voltage by the relative ratio of transformers at  
4 current installation costs except for the street and area lighting class which is assigned its  
5 proportion of noncoincident peak to the sum of noncoincident peaks for all secondary voltage  
6 customers. For poles, conduit, and wires, this study allocates the customer groups (not directly  
7 assigned) by the average of 12 monthly distribution system noncoincident peaks separately  
8 for primary system and secondary system customers. These methods are consistent with the  
9 methodology presented in Dockets UE-220053 et. al.

10 **Q. How are customer-related distribution costs treated in this study?**

11 A. Service line costs and meter costs are allocated to customer rate schedules by  
12 customer count multiplied by installed cost of new service lines and meters, respectively.  
13 Customer service and billing operating expenses are allocated by customer counts and  
14 weighted, if appropriate. This method is consistent with prior Avista electric cost of service  
15 studies.

16 **Q. How are administration and general operating expenses and general plant**  
17 **costs treated in this study?**

18 A. Property insurance and taxes are functionalized and allocated based on plant  
19 in service. Pensions and employee insurance expenses are allocated based on salary and  
20 wages. FERC fees are identified and allocated based on energy consumption. Revenue-based  
21 fees, uncollectible accounts expenses, and excise taxes are allocated by relative share of total  
22 revenue. Other administrative and general costs which can be directly associated with  
23 production, transmission, distribution, or customer relations functions based on Company

1 department (expenditure organization) are directly assigned to those functions and then  
2 allocated to customer class by the relevant plant or number of customers associated with the  
3 function.

4 The remainder of administrative and general expenses and general plant costs are  
5 considered common costs and are allocated to customer rate classes by the Company's four-  
6 factor allocator. This allocation factor is the cost of service equivalent of the four-factor  
7 allocator used in the Company's results of operations reporting. The four-factor has  
8 historically been utilized by the Company to allocate common operating costs and plant  
9 between States (Washington, Idaho, and Oregon) and among services (electric and natural  
10 gas) for purposes of the Company's Commission Basis results of operations.

11 **Q. Please describe the components of the four-factor allocation.**

12 A. The four-factor allocation is comprised of the following four equally weighted  
13 components:

- 14 • Direct O&M excluding resource costs and labor
- 15 • Direct O&M labor
- 16 • Number of customers
- 17 • Net direct plant

18  
19 **Q. Please describe the benefits of the four-factor allocator.**

20 A. There are two primary benefits of the four-factor allocation. First, it reflects a  
21 variety of relationships that are consistent with the specific costs and plant items which are  
22 recognized as serving multiple functions. Second, it provides consistency and balance  
23 between the way common costs are allocated for purposes of Commission Basis results of  
24 operations and the cost of service study used in general rate cases. This method is consistent  
25 with the methodology presented in Dockets UE-220053 et. al.



1           **Q. Did the Company prepare an analysis of Intangible Plant accounts while**  
2 **preparing this cost of service Study?**

3           A. Yes. Account 302 was segregated between generation-related hydro  
4 relicensing agreements, transmission-related forest use permits, and distribution-related  
5 department of transportation franchises. Account 303.000 was segregated between  
6 transmission-related communication agreements, distribution-related communication  
7 agreements and miscellaneous intangible assets considered common costs. Account 303.120  
8 and 303.121 software costs are associated with the meter data management system (MDM)  
9 and advanced metering infrastructure (AMI) project and have been allocated by number of  
10 customers. An analysis of Account 303.100 computer software by project is included in the  
11 Company workpapers. No additional functionalization resulted from the project level analysis.  
12 Common intangible plant costs have been allocated based on tangible plant. This treatment of  
13 intangible plant costs is consistent with the Company's past electric cost of service studies.

14           **Q. Has the Company met with interested parties and reached an agreement**  
15 **on how the Special Contract approved in the Company's general rate case, Dockets UE-**  
16 **200900 et. al., is to be incorporated into the filed cost of service study?**

17           A. Yes. The final order of the Company's general rate case, Dockets UE-200900  
18 et. al., approved the Special Contract<sup>6</sup> with conditions, including that the Company was to  
19 meet with interested parties to discuss how the Special Contract will be treated in future cost  
20 of service studies and file a report within 180 days of the order (by April 1, 2022), indicating  
21 whether interested parties have reached an agreement. In accordance with that provision, the

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<sup>6</sup> Entered into with Inland Empire Paper (IEP) and approved by the Commission in Docket UE-200900.

1 Company filed a report to the Commission on March 31, 2022 in that docket stating that the  
2 Company coordinated a virtual meeting with all interested parties who participated in the  
3 docket. The meeting was held March 9, 2022 and the interested parties represented at the  
4 meeting were Commission Staff, Public Counsel, Alliance of Western Energy Consumers,  
5 and the Inland Empire Paper Company. At the meeting, Avista presented three scenarios for  
6 including the Special Contract in future cost of service studies and the parties reached a  
7 consensus on the following approach:

8 Future cost of service studies will exclude the Special Contract  
9 characteristics. Revenue associated with the Special Contract will be included  
10 as “other revenue” that offsets costs for all other customer groups in  
11 proportion to production and transmission rate base, if feasible, or  
12 alternatively by production and transmission plant.<sup>7</sup>  
13

14 **Q. How was the Special Contract approved in the Company’s general rate**  
15 **case, Dockets UE-200900 et. al., incorporated into the filed cost of service study?**

16 A. The Special Contract was incorporated into the cost of service study in  
17 accordance with the methodology agreed upon with interested parties, as previously  
18 described.

19

## 20 **Rate Class Results**

21 **Q. What are the results of the Company’s electric cost of service study**  
22 **presented in this case?**

23 A. Exhibit No. MJG-2, Section E presents a high-level summary of the rate class

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<sup>7</sup> Compliance filing document labeled “Special Contract Cost of Service Report” filed in Docket UE-200900 on March 31, 2022.

1 results in the form required by the WAC 480-85-040(1) electric cost of service template.  
 2 Table No. 4 shows the rate of return and the relationship of the customer class return to the  
 3 overall return (relative return ratio) in addition to the revenue-to-cost Parity Ratio at present  
 4 rates for each rate schedule:

5 **Table No. 4 – Electric Cost of Service Base Case Results**

6 <u>Customer Class</u>	<u>Rate of Return</u>	<u>Return Ratio</u>	<u>Parity Ratio</u>
7 Residential Service Schedules 01/02	4.53%	0.59	0.86
8 General Service Schedule 11/12	11.59%	1.52	1.18
9 General Service Optional EV Charging Schedule 13	-6.43%	-0.85	0.27
10 Large General Service Schedules 21/22	12.23%	1.61	1.21
11 Large General Service Optional EV Charging Schedule 23	-8.54%	-1.12	0.14
12 Extra Large General Service Schedule 25	12.85%	1.69	1.20
13 Pumping Service Schedules 30/31/32	8.63%	1.13	1.05
14 Lighting Service Schedule 41 - 48	<u>8.54%</u>	<u>1.12</u>	<u>1.06</u>
15 Total Washington Electric System	<u>7.61%</u>	<u>1.00</u>	<u>1.00</u>

18  
 19  
 20 As can be observed in Table No. 4, Residential Service (Schedule 01), General Service  
 21 Optional Electric Vehicle (Schedule 13), and Large General Service Optional Electric Vehicle  
 22 (Schedule 23) shows under-recovery of the costs to serve them. Pumping service (Schedules  
 23 30/31/32) and Lighting Service (Schedules 41 - 48) are relatively close to unity with the  
 24 overall return from present rates. The other customer classes, however, show over-recovery  
 25 of the costs to serve them (currently providing in excess of the requested rate of return).

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

27 A. Yes.