Exh. MJG-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DIRECT TESTIMONY OF

MARCUS J. GARBARINO

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

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

Q. What is your educational background and professional experience?

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

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

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

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exh. MJG-2 which presents the electric cost of service study results in the form of the electric cost of service template provided by the Commission in accordance with WAC 480-85-040(1). This exhibit was prepared by me and consists of summaries of information derived from the Electric Cost of Service Study. I am also sponsoring Exh. MJG-3 (weather normalization) and Exh. MJG-4 (revenue normalization).

II. SUMMARY

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

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

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

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

Customer Class	Rate of Return	Return Ratio	Parity Ratio
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	6.95%	1.36	1.06
Total Washington Electric System	5.10%	1.00	1.00

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

[1] 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.

III. ELECTRIC REVENUE NORMALIZATION

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

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

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

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

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

Weather Normalization

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

[2] There were no decoupling contra-revenues recorded during the test period.
[3] Dockets UE-220053 et. al.

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

Q. Please briefly summarize the electric weather normalization process.

A. The Company's electric weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the 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 an analysis of ten years (January 2013 through December 2022) of calendarized usage-per-customer and calendar period heating and cooling degree-day data. The resulting monthly weather sensitivity factors (use-per-customer-per-heating-degree day and use-per-customer-per-cooling-degree day) are applied to the difference between normal heating/cooling degree-days and monthly test year observed heating/cooling degree-days. This calculation produces the change in kWh usage required to adjust actual test period loads to the amount expected if weather had been normal.

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

A. The methodology is generally consistent, but in this case the Company is proposing to make two changes to the weather normalization methodology. First, the Company proposes to change the definition of "normal" from a 30-year to a 20-year rolling average. Second, the Company proposes to adjust its non-degree day seasonal regression factors from seasonal factors to monthly factors. These two changes are discussed in detail in Company witness Dr. Forsyth's testimony (Exh GDF-1T).

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

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

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 20-year average of heating and cooling degree-days reported for each month by the National Weather Service for the Spokane International 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. The calculation includes the 20-year period from 2003 through 2022.

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

A. Weather was warmer than normal during the July 2022 through June 2023 period. Since electric usage is impacted by both heating and cooling, weather normalization required an increase to usage for warm weather during the winter/fall months and a reduction to usage for hot weather during the summer months. Overall, the adjustment to normal required an increase of 134 heating degree-days and the reduction of 319 cooling degree-days during the test period. The annual total adjustment to Washington electric sales volumes was a reduction of 112,314,908 kWhs, which is approximately 1.9% of billed usage.

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

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

Table No. 2: - Weather Normalization Adjustment Summary

General Business Revenue (Sales)	($10,306,000)
Other Revenue (Decoupling Deferred)	$8,423,000
Total Revenue (Net Adjustment)	($1,883,000)
Less: Revenue Related Expenses	$489,000
Less: Income Tax Expense	$293,000
Net Operating Income	($1,101,000)

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

[4] The Decoupling Mechanism went into effect January 1, 2015.

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

Eliminate Adder Schedules

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

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

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

A. The Eliminate Adder Schedule adjustment results in a nearly equal and offsetting reduction to both revenue and expense unless contra-decoupling entries were recorded in the test period. As noted in footnote 2 above, there were no decoupling contra-revenues recorded during the test period, and the resulting adjustment was an increase to net income of $2,000.

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

<u>Pro Forma Revenue</u>

Q. Please describe the purpose of the <u>third revenue normalizing</u> adjustment, the Pro Forma Revenue Normalization adjustment.

A. The purpose of the Pro Forma Revenue Normalization adjustment (3.01) is to restate revenue on a forward-looking basis. This is accomplished by re-pricing test period normalized billing determinants (including unbilled and weather adjustments, as well as any known and measurable changes to the test period loads and customers) to reflect revenues for the July 2022 through June 2023 test period, as if the base tariff rates approved in Dockets UE-220053 et. al. effective December 21, 2023, had been in effect for the full 12 months of the test period.[5]

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

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

Table No. 3 – Summarize Revenue Normalization Adjustment

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

IV. ELECTRIC COST OF SERVICE

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

[5] 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.

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.

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 Exh. MJG-2 is based on the 12-months ended June 2023 test period pro forma results of operations for Rate Year 1 presented by Ms. Schultz as Exh. KJS-2.

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

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

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

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

Methodology

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

A. Yes, the Base Case cost of service study was prepared using the same methodology used in our previous rate case, which complies with the methodology described in WAC 480-85-060.

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

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

Q. How are generation costs treated in this study?

A. In this study, generation costs (production plant related rate base and expenses including operation and maintenance, depreciation and taxes) have been classified as energy or demand-related based on a renewable future peak credit ratio, with net power costs considered 100% energy. The demand-related portions were allocated to customer rate classes based on the average of 12 system coincident peaks determined from power supply native load, excluding renewable generation. The energy-related portions were allocated to customer rate classes based on annual energy usage at the point of generation.

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

Q. How are transmission costs treated in this study?

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

Q. How are distribution costs treated in this study?

A. This study follows methodology set forth in WAC 480-85-060 utilizing allocation factors for the customer rate classes that are not directly assigned, and directly assigning distribution substations, poles, conduit, and wires to the Extra Large General Service schedule 25 based on the load ratio share of substations they are fed from. For distribution substations, this study allocates these classes by the average of the relative share of the summer distribution system coincident peak and the relative share of the winter distribution system coincident peak. Distribution line transformer costs are allocated to customers who receive power at secondary voltage by the relative ratio of transformers at current installation costs except for the street and area lighting class which is assigned its proportion of noncoincident peak to the sum of noncoincident peaks for all secondary voltage customers. For poles, conduit, and wires, this study allocates the customer groups (not directly assigned) by the average of 12 monthly distribution system noncoincident peaks separately for primary system and secondary system customers. These methods are consistent with the methodology presented in Dockets UE-220053 et. al.

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

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

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

A. Property insurance and taxes are functionalized and allocated based on plant in service. Pensions and employee insurance expenses are allocated based on salary and wages. FERC fees are identified and allocated based on energy consumption. Revenue-based fees, uncollectible accounts expenses, and excise taxes are allocated by relative share of total revenue. Other administrative and general costs which can be directly associated with production, transmission, distribution, or customer relations functions based on Company department (expenditure organization) are directly assigned to those functions and then allocated to customer class by the relevant plant or number of customers associated with the function.

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

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

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

- Direct O&M excluding resource costs and labor
- Direct O&M labor
- Number of customers
- Net direct plant

Q. Please describe the benefits of the four-factor allocator.

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

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

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

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

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

[6] Entered into with Inland Empire Paper (IEP) and approved by the Commission in Docket UE-200900.

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

> Future cost of service studies will exclude the Special Contract characteristics. Revenue associated with the Special Contract will be included as "other revenue" that offsets costs for all other customer groups in proportion to production and transmission rate base, if feasible, or alternatively by production and transmission plant.[7]

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

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

Rate Class Results

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

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

[7] Compliance filing document labeled "Special Contract Cost of Service Report" filed in Docket UE-200900 on March 31, 2022.

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

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

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

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

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

A. Yes.