Exh. KJS-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

DIRECT TESTIMONY OF

KAYLENE J. SCHULTZ

REPRESENTING AVISTA CORPORATION

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I. INTRODUCTION

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

A. My name is Kaylene J. Schultz. I am employed by Avista Corporation as Manager of Regulatory Affairs in the Regulatory Affairs Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I am a 2010 graduate from Gonzaga University with a Bachelor of Business Administration degree, majoring in both Accounting and Business Administration, with a concentration in Management Information Systems. After spending nearly eight years in the banking and capital markets sector, I joined Avista in September 2015 as a Natural Gas Analyst in the Company's Gas Supply Department, now Energy Supply. In January 2019, I joined the Regulatory Affairs Department as a Regulatory Affairs Analyst where I was responsible for preparing various annual filings and applications. In my current role as Manager of Regulatory Affairs, my primary areas of responsibility include preparation of general rate case filings, and annual power supply-related filings, among other things.

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

A. My testimony and exhibits in this proceeding will cover accounting and financial data in support of the Company's electric and natural gas Two-Year Rate Plan and the need for the proposed increases in base rates effective late December 2024 (Rate Year 1 or RY1) and late December 2025 (Rate Year 2 or RY2).[1] I will explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base. Included with the restating, pro forma and provisional adjustments are certain adjustments sponsored by other witnesses, from which I incorporate the Washington-share of those adjustments in this case. The pro formed operating results for Rate Year 1 effective in late December 2024, reflect electric and natural gas base revenue requirement requests of approximately $77.1 million and $17.3 million, respectively. The pro formed operating results for Rate Year 2 effective in late December 2025, reflect electric and natural gas base revenue requirement requests of approximately $78.1 million and $4.6 million, respectively.

Q. Would you please summarize your direct testimony?

A. Yes. Below is a summary of the principal topics discussed in my direct testimony:

- The Company is requesting a Two-Year Rate Plan, with rates taking effect in late December 2024 and late December 2025.

- For RY1, the proposed increases reflect an electric base rate relief of approximately $77.1 million, or 13.0% (12.6% billed), and natural gas base rate relief of $17.3 million, or 13.6% (6.3% billed).

- For RY2 of the Two-Year Rate Plan, the electric proposed increase reflects a base rate relief of $78.1 million, or 11.7% (or on a billed basis $53.7 million, or 7.8%, after taking into account the mandated removal of certain Colstrip costs effective January 1, 2026 currently included in Colstrip Tariff Schedule 99). For natural gas, the proposed increase reflects base rate relief of approximately $4.6 million, or 3.2% (billed 1.6%).

- The Company has included "pro forma" capital adjustments, consistent with the prior WA GRC (Dockets UE-220053, et. al.) as sponsored by Company witness Ms. Benjamin, in this case reflecting all capital additions (excluding Colstrip Units 3 & 4) for the six-month period July 2023 through December 2023, and

[1] The Company proposes that Rate Year 1 have an effective date that slightly pre-dates January 1, 2025. For ease of discussion, however, I will refer to calendar year 2025 as being Rate Year 1 (RY1) and calendar year 2026 as being Rate Year 2 (RY2).

calendar 2024.[2]

- The Company has also included “provisional” capital adjustments, consistent with the prior WA GRC (Dockets UE-220053, et. al.), as sponsored by Ms. Benjamin, for the period January 2025 through December 2025 for RY1, and January 2026 through December 2026 for RY2. Inclusion of the provisional capital investments were prepared using the category designations discussed by the Commission’s “Used and Useful Policy Statement,” dated January 31, 2020 in Docket U-190531, including capital investments grouped as “Large or Distinct”, “Programmatic”, “Short-Lived” and “Mandatory and Compliance.” These capital additions, in conjunction with the pro forma capital additions, are the main driver of the Company’s request for rate relief in RY1 and RY2. As further discussed by Ms. Benjamin, the Company is proposing Provisional Reporting requirements of all provisional capital investment included in the Company’s case for capital investment from January 2025 through December 2026. This reporting provides a means for the review of actual capital investments as a check against the provisional level requested and approved in this case and allows for an auditing process that would help validate the level of plant investment ultimately that is used and useful during the rate effective periods. This process is the same as was used in the Company’s last Multi-Year Rate Plan (MYRP).

- As discussed by Company witness Ms. Andrews, the Company has included in its electric and natural gas Pro Forma Studies, total O&M offsets, other revenue, retirements (reduced depreciation expense), and reduced net plant after accumulated deferred federal income taxes (ADFIT) for the change in accumulated depreciation (A/D) and ADFIT on existing plant at June 30, 2023, adjusted to AMA 2025 for RY1 and AMA 2026 for RY2. These adjustments reduce the Company’s revenue requirement in total by $49.5 million for electric and $9.3 million for natural gas, for RY1, and by $20.1 million for electric and $3.2 million for natural gas, for RY2, or a total of $69.6 million for electric and $12.5 million for natural gas, over the Two-Year Rate plan.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exh. KJS-2 through KJS-4, which were prepared by me as follows:

[2] Actual capital additions for July 2023 and expected capital additions for August through December 2023 were included in the Company’s electric and natural gas Pro Forma Adjustment (3.15). These additions pro form balances beyond the Company’s historical test period – twelve-months ending (12ME) June 30, 2023. Consistent with prior practice, actual transfers to plant for August through December 2023 will be provided to all Parties through discovery as soon as available.

Exh. KJS-2 (Electric) and Exh. KJS-3 (Natural Gas) present the results of the Company's Washington Electric and Natural Gas Two-Year Rate Plan Pro Forma Studies. These studies show actual twelve-month period ending June 30, 2023 ("12ME 06.30.2023") operating results, pro forma, and proposed electric and natural gas operating results and rate base for RY1 and RY2 of the Two-Year Rate Plan. These two exhibits also show the calculation of the Two-Year Rate Plan general revenue requirements, the derivation of the Company's overall proposed rate of return, the derivation of the net-operating-income-to-gross-revenue-conversion factor, and the specific restating, pro forma and provisional adjustments proposed in this filing for RY1 and RY2. Finally, Exh. KJS-4 provides the service and jurisdiction allocation methodologies used by the Company.

SECTION 1 – TWO-YEAR RATE PLAN

II. REVENUE REQUIREMENT SUMMARY - TWO-YEAR RATE PLAN

Q. Please summarize the proposed electric and natural gas revenue and percentage increases proposed by the Company in this case over the Two-Year Rate Plan.

A. Provided in Table No. 1 below is a summary of the proposed electric and natural gas revenue and base percentage increases proposed by the Company in this case over the Two-Year Rate Plan. Also summarized for Washington electric is the proposed billed revenue and percentage impact, after reflecting the mandated removal of certain Colstrip costs (net rate base, depreciation and fixed operations and maintenance expense) from Customer rates effective January 1, 2026, currently included in Colstrip Tariff

Schedule 99.[3]

Table No. 1 – Two-Year Rate Plan Revenue Requirement & Percentages

Two Year Rate Plan Revenue Requirement & Percentage Increases (000s)						
Service	**RY1 (2025)**			**RY2 (2026)**		
	Revenue	**Base %**	**Billed %**	**Revenue**	**Base %**	**Billed %**
WA Electric	**$ 77,067**	**13.0%**	**12.6%**	**$ 78,130**	**11.7%**	**11.4%**
Colstrip Tariff 99 Offset				**$ (24,419)**		**(3.6%)**
Bill Impact				**$ 53,711**		**7.8%**
WA Natural Gas	**$ 17,293**	**13.6%**	**6.3%**	**$ 4,565**	**3.2%**	**1.6%**

As shown in Table No. 1, the proposed RY1 base electric increase is $77.067 million or 13.0% (12.6% on an overall billed basis). The proposed RY1 base natural gas increase is $17.293 million or 13.6% (6.3% on an overall billed basis).

The proposed RY2 base electric increase is $78.130 million or 11.7% (11.4% on an overall billed basis, prior to the impact of Tariff Schedule 99). After taking into account the Colstrip Tariff Schedule 99 offset January 1, 2026, the proposed RY2 billed electric increase is $53.711 million or 7.8%. The proposed RY2 base natural gas increase is $4.565 million or 3.2% (1.6% on an overall billed basis).

Q. On what test period is the Company basing its need for additional

[3] As discussed by Company witness Ms. Andrews, Tariff Schedule 99 "Colstrip Tracker," includes the recovery of Avista's Colstrip Units 3 and 4 costs (exclusive of transmission investment and those costs included in the Energy Recovery Mechanism ("ERM")), including operating and maintenance ("O&M") and other expenses, depreciation expense, decommissioning and remediation ("D&R") costs, and return on rate base. Effective January 1, 2026, the Company is mandated to remove all Colstrip costs from customer rates, with the exception of D&R costs. After January 1, 2026, Tariff Schedule 99 will be on-going, reflecting only the recovery of D&R Regulatory Asset/Liability balances and amortization expense. The Colstrip Tariff 99 Offset shown above reflects the existing calendar 2024 Tariff Schedule 99 recovery amount and may not be reflective of the actual balances removed as of January 1, 2026.

electric and natural gas revenue?

A. The <u>test period</u> being used by the Company to base its need for additional electric and natural gas revenue is the twelve-month period ending June 30, 2023 ("12ME 06.30.2023"), presented on a pro forma basis. Current authorized rates were based upon the twelve-months ending September 30, 2021 test year utilized in Dockets UE-220053 et. al., adjusted on a pro forma basis.

Q. Why did the Company choose to use an electric and natural gas historical test period ending as of June 30, 2023?

A. Specific to Avista's use of its historical test period of 12 months ending June 30, 2023, Avista has historically used a test period providing a period of approximately four (4) months prior to the Company's filing. In this case, however, in order to provide the time necessary to complete the preparation of its case, the Company is using a historical test period resulting in approximately six and one-half (6.5) months prior to the Company's filing. As case complexities have continued to grow over time, requiring more time to prepare each case, especially given that utilities are required to file at least a Two-Year Rate Plan, the Company required additional time to develop its case. As discussed by Company witness Mr. Vermillion, Avista is supporting its Two-Year Rate Plan with 21 witnesses, covering numerous, complex issues.

In addition, the Company believes the use of a calendar quarter end (i.e., March, June, September, or December) provides the best auditable results of operations, as the use of quarter-end data utilizes data that is released publicly on a quarter basis and is audited by the Company's external Accounting and Auditing firms. Quarter and year-to-date financial results are complete, account for material changes, reflect proper accrual accounting of costs, and provide complete financial information. Had the Company used September instead of June, it would not have been able to file this rate case until April; it would still take the same amount of time to develop a thorough case.

Q. What are the Company's rates of return that were last authorized by this Commission for its electric and natural gas operations in Washington?

A. The Company's current authorized rate of return for its Washington operations is 7.03%, effective December 21, 2022, for both its electric and natural gas systems, approved in Dockets UE-220053 et. al.

Q. By way of summary, please explain the different rates of return that you will be presenting in your testimony.

A. There are four different rates of return that are provided. They are (1) the actual ROR earned by the Company during the 12ME 06.30.2023 test period, (2) the Restated 06.30.2023 results for the historical test period (representing 06.2023 normalized Commission Basis (CB) ROR[4], adjusted to 06.2023 EOP Net Plant basis), (3) the adjusted ROR for RY1 and for RY2 determined in my exhibits Exh. KJS-2 (electric) and Exh. KJS-3 (natural gas), and (4) the requested ROR. The returns for Washington operations are provided below in Illustrations No. 1 (electric) and No. 2 (natural gas):

[4] Normalized Commission Basis reports for calendar 2023 will be filed with the Commission on or before April 30, 2024.

Illustration No. 1: Two-Year Rate Plan - Electric Rates of Return

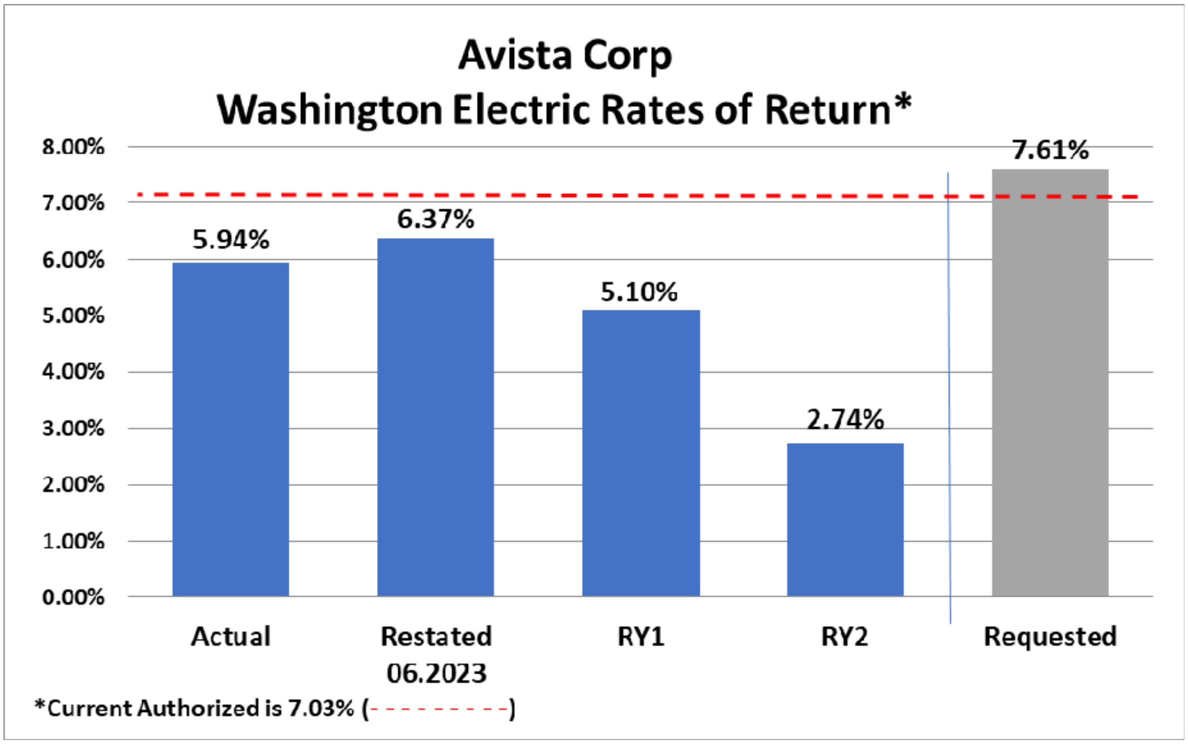
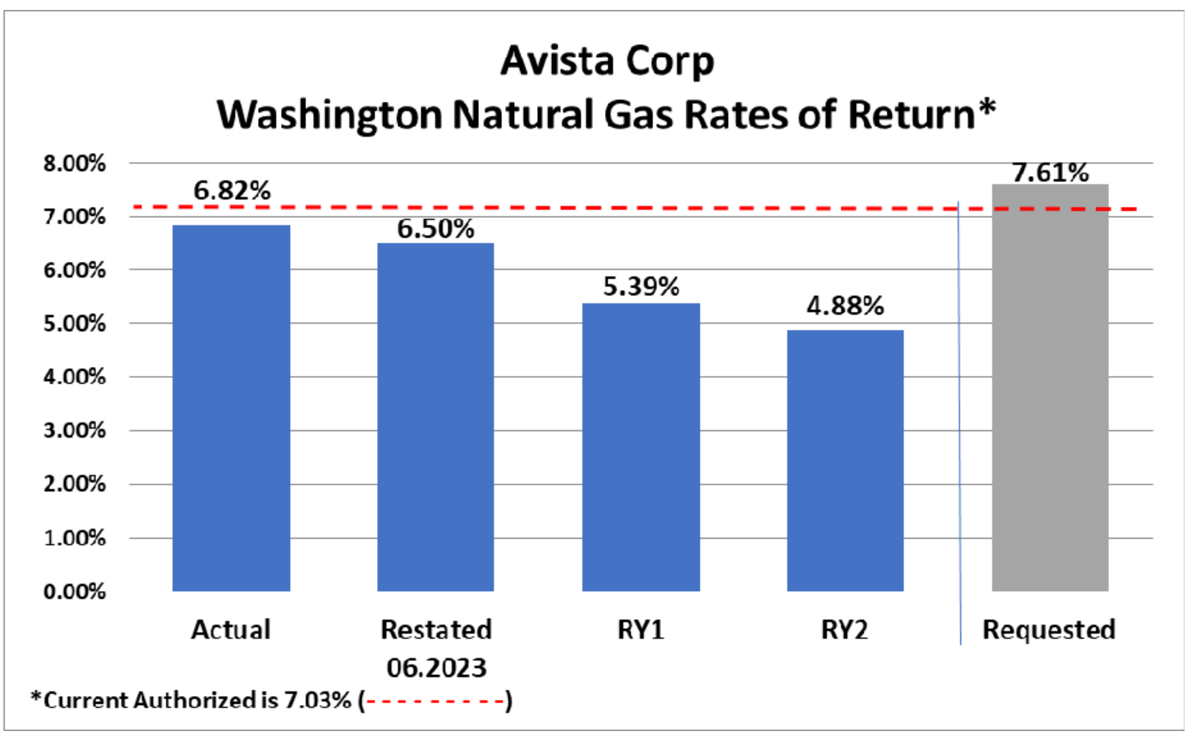


Illustration No. 2: Two-Year Rate Plan - Natural Gas Rates of Return



As shown in Illustration Nos. 1 and 2 above, after taking into account all standard Commission Basis adjustments, as well as additional normalizing, pro forma and provisional adjustments, the pro forma electric and natural gas rates of return ("ROR") for the Company's Washington jurisdictional operations over the Two-Year Rate Plan are 5.10% and 5.39%, respectively for RY1; and 2.74% and 4.88%, respectively for RY2. These return levels over the Two-Year Rate Plan are well below the Company's requested rate of return of 7.61%. The incremental base revenue requirement necessary to give the Company an opportunity to earn its requested ROR in <u>RY1</u> is $77.067 million for the electric operations and $17.293 million for the natural gas operations. The incremental base revenue requirement necessary to give the Company an opportunity to earn its requested ROR in <u>RY2</u> is $78.130 million for the electric operations and $4.564 million for the natural gas operations.

Q. What is the importance of the Commission approving a reasonable first year revenue requirement?

A. As discussed further by Company witness Mr. Vermillion, in any multi-year rate plan, the first-year revenue requirement approved by the Commission will persist for each year of the rate plan and is the basis for additional revenue adjustments in years 2, 3 and beyond. If the revenue requirement is sufficient for the first year of the rate plan, and the next year is built off of that revenue requirement, the utility would have a reasonable opportunity to earn its allowed rate of return. However, if the first-year revenue requirement is insufficient, that insufficiency will persist, and the approved revenue requirement for the next year will not correct for that. In this Two-Year Rate Plan as proposed by the Company, it is essential for this Commission to approve a sufficient RY1 revenue requirement, if the

Company has any opportunity to earn its allowed rate of return during the approved Two-Year Rate Plan. Simply put, we need to "get the first year right" in any Rate Plan.

Q. Please now summarize the preparation of the Company's electric and natural gas Two-Year Rate Plan Pro Forma Studies.

A. The Company is proposing a Two-Year Rate Plan with electric and natural gas rate increases effective December 2024 and December 2025. The Company has prepared traditional electric and natural gas pro forma studies, including restating, pro forma and provisional adjustments beyond the historical test year for both RY1 and RY2 of the Two-Year Rate Plan. First, included with the electric and natural gas restating adjustments is an End-Of-Period (EOP) 06.2023 Net Plant adjustment, adjusting net plant from an average-of-monthly-average (AMA) 06.2023 historical test year balance to a 06.2023 EOP net plant historical test-year balance, similar to that approved by the Commission in Avista's last general rate case proceeding.[5]

Additional normalizing, pro forma, and provisional adjustments were then included to adjust the Company's restated results to reflect rate period net operating income and rate base results for RY1 and RY2. Included as "pro forma" capital addition adjustments in RY1, are investments that are anticipated to be complete and in service as of December 31, 2024.[6] The Company has also included "provisional" capital adjustments, subject to further review

[5] Dockets UE-220053 et. al.

[6] Due to the timing of completion of the Company's Two-Year Rate Plan revenue requirements in mid-December 2023, the Company included actual transfers to plant through July 31, 2023. Consistent with prior practice, actual transfers to plant for August through December 2023 will be provided to all Parties through discovery as soon as available. As explained later in my testimony, the Company has included capital investment through December 31, 2024 as "pro forma," because the Commission approved the level of net plant over the Company's Two-Year Rate Plan for calendar years 2023 and 2024 in Dockets UE-220053 et. al., contingent upon the provisional capital review filings in March 2024 for 2023 capital investments and in March 2025 for 2024 capital investments, where actual investments and net plant after ADFIT will be reviewed against that approved in the prior case.

through the Company's proposed annual Provisional Capital Reporting process as described by Ms. Benjamin, for the period January 2025 through December 2025 for RY1, and January 2026 through December 2026 for RY2. Finally, also included are pro forma adjustments, as discussed by Ms. Andrews, to reflect all offsetting factors determined by the Company to impact RY1 and RY2, to ensure a "matching" of revenues, expenses, and rate base, by rate year, over the Two-Year Rate Plan. The process or methodology described above to prepare the Company's Two-Year Rate Plan results in this case, is consistent with that approved by the Commission in the prior general rate case.[7]

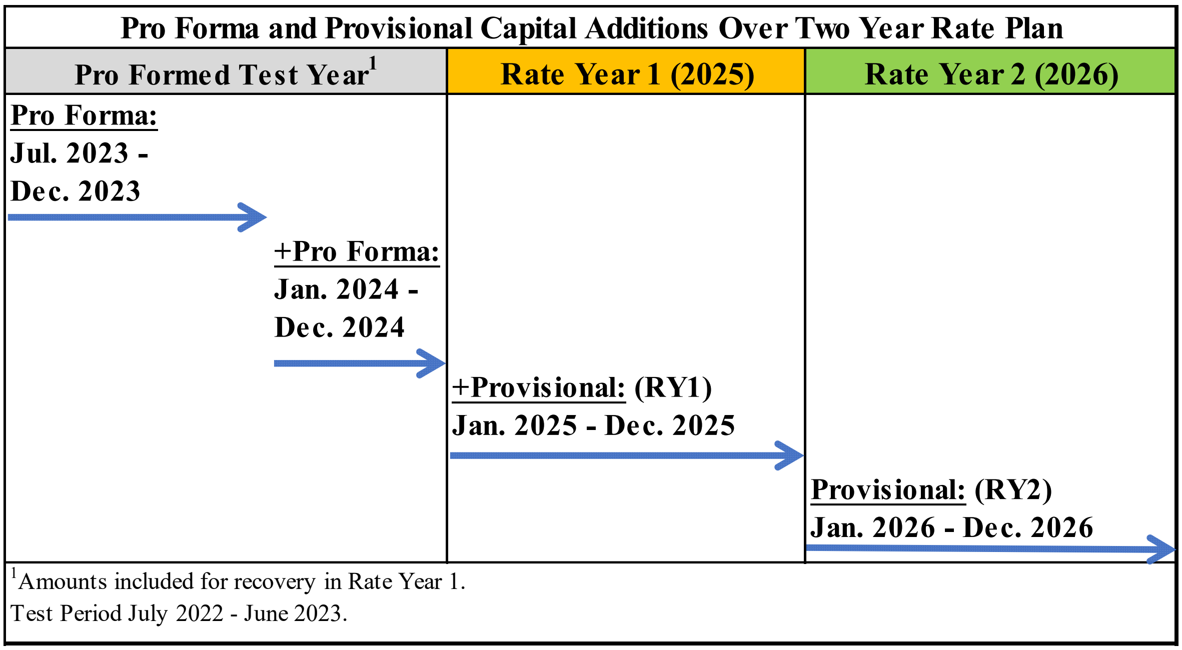
As discussed later in my testimony, without inclusion of the EOP 06.2023 Net Plant adjustment, as well as the pro forma capital additions for July 2023 through December 2024 – adjusting restated 06.2023 EOP to 12.31.2024 EOP in RY1, and the "provisional" capital adjustments for capital additions from January 2025 through December 2026 included on an AMA basis in RY1 and RY2, reducing the regulatory lag experienced by the Company, the Company would have no reasonable opportunity to earn its authorized rate of return proposed in this case for the Two-Year Rate Plan. The results of the electric and natural gas Pro Forma Studies are provided as Exhs. KJS-2 and KJS-3, respectively.

Q. By way of summary, do you have a simple illustration of how pro forma test period capital and "provisional" capital are incorporated in the case?

A. Yes, as discussed in more detail and illustrated by Ms. Benjamin, Illustration No. 3 below provides a simple schematic of capital addition inclusion during the Two-Year Rate Plan.

[7] Dockets UE-220053 et. al.

Illustration No. 3 – Pro Forma and Provisional Capital Additions



III. COMMISSION RATEMAKING GUIDANCE

Q. Please discuss the ratemaking guidance, either obtained specifically from the Commission in recent years, or in recent legislation, that the Company relied upon in preparation of this case.

A. In general, the Company relied upon its most recent general rate cases[8], as well as other prior general rate case orders for Avista, or other peer utilities, the Commission's January 31, 2020 "Policy Statement on Property That Becomes Used and Useful After Rate Effective Date" ("Policy Statement")[9], as well as the Engrossed Substitute Senate Bill 5295 (SB 5295), signed into law in May of 2021 (and effective in July 2021).[10] This guidance was used in order to utilize proper ratemaking treatment as required by the

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[8] Dockets UE-220053 et. al.
[9] Docket U-190531
[10] On May 3, 2021, Governor Inslee signed into law Engrossed Substitute Senate Bill 5295.

Commission, in a manner that provides Avista with a reasonable opportunity to recover its costs and earn a fair return.

Q. What guidance with regards to "used and useful" property did the Commission provide in its Policy Statement, and was relied upon by the Company in the development of this case?

A. With regards to recovery of used and useful property, at paragraph 28 of the Policy Statement, the Commission stated its intent is to achieve four goals:

> (1) Ensure general consistency with longstanding ratemaking practices, principles, and standards; (2) Maintain flexibility; (3) Avoid overly prescriptive guidance; and (4) Support streamlined processes by requiring additional process only when necessary.[11]

With this guidance, the Commission outlined its process for review of proposed investments that become used and useful <u>after</u> the rate effective date, as follows[12]:

- <u>Identification of investments</u> - the Commission defined three broad types of investments they would consider for inclusion in rates: 1) <u>specific</u> - clearly defined, identifiable or discrete; 2) <u>programmatic</u> - made according to a schedule, plan or method; and 3) <u>projected</u>: i.e., the use of a k-factor, an attrition adjustment, or a growth analysis.

- <u>Provisional Adjustments</u> - Rate-period investment must be separately identified from traditional pro forma rate-base adjustments, through the use of a "provisional" pro forma adjustments, and then must state whether they are seeking recovery through base rates or a separate tariff schedule.

- <u>Offsetting Factors</u> - Companies must include the estimated or projected costs (including all offsetting factors and duplicative recovery considerations) and a description of the investment, as well as other existing documentation, for a project that will be subject to review and audit during a future period.

- <u>In-Service Dates</u> - Companies must provide the expected in-service date that

[11] At paragraph 32 of the Policy Statement, the Commission noted: "The Commission encourages regulated companies to streamline their requests by using existing reporting frameworks and limiting additional or duplicative processes. For example, a request is not "streamlined" if it creates unnecessary or burdensome processes.

[12] See Used and Useful Policy Statement, Docket No. U-190531, para. 11, p. 5 and para. 34, p. 11.

will occur during the rate effective period.

Q. How has the Company met the guidance provided by the Commission, as discussed above?

A. First, as discussed by Ms. Benjamin, the Company has categorized its pro formed capital investments in this case to reflect the identified categories, specifically as follows: 1) specific, identifiable and distinct; 2) programmatic (on-going programs or scheduled investments), and 3) short-lived assets[13]. The Company created a 4th category – (Mandatory and Compliance) reflecting projects that are mainly "programmatic," and required to meet regulatory and other mandatory obligations.

Second, the Company has separately identified its pro formed capital investments it has included in its Two-Year Rate Plan as pro formed "provisional" adjustments for the period January 2025 through December 2026. As the Company has included this capital investment in its Two-Year Rate Plan in its electric and natural gas Pro Forma Studies, Avista requests they be approved as a part of base rates in this proceeding, and the Company has provided its proposal for Provisional Reporting, and process for review and refund, if any, as discussed by Ms. Benjamin, all of which is consistent with the Company's most recent MYRP.

Finally, through its capital witnesses' testimony and exhibits, the Company has included information on all Business Cases included in the Company's case, including

[13] The Commission discussed their consideration of Short-Lived assets in Order 08, Puget Sound Energy (PSE) general rate case, Dockets UE-190529 and UG-190530.

expected costs, by in-service date[14], description of the investment, and necessary existing documentation to support these projects, and designated "provisional," as noted above, as subject to review and audit during a future period. Furthermore, as discussed by Ms. Andrews, the Company discusses its inclusion of all "offsetting factors" totaling $69.6 million for electric and $12.5 million for natural gas, over the Two-Year Rate plan. In doing so, the Company has ensured that over the Two-Year Rate Plan, in each RY1 and RY2, the Company is "matching" revenues, expenses and rate base, by rate year.

The Provisional Reporting as proposed by the Company will provide additional support, and will serve to validate that plant is, in fact, in-service, is used and useful and at what cost (after any offsetting benefits). This will provide the Commission with assurance that the pro forma capital included prior to the rate effective period (for 2023-2024 capital) and provisional capital included during RY1 (2025 capital) and RY2 (2026 capital) is in service for customers during the rate effective periods, or will be subject to refund, with interest.

IV. PRIMARY FACTORS DRIVING NEED FOR RATE RELIEF

Q. What are the primary factors driving the Company's requested electric and natural gas revenue increases?

A. The primary factor driving the Company's electric and natural gas revenue

[14] All of Washington's share of directly assigned or allocated transfer-to-plant data (actual or expected) is provided by Business Case, by witness, by month (the in-service "used and useful" date) within Ms. Benjamin's testimony and exhibits pro formed in the Company's case. Testimony and exhibits in support of the capital Business Cases are provided by capital witnesses: Mr. Alexander regarding production assets; Mr. DiLuciano regarding transmission, distribution and general assets; Mr. Manuel regarding the costs associated with Avista's IS/IT projects and short-lived assets; Ms. Hydzik regarding transportation electrification and customer technology projects; and Mr. Howell regarding Wildfire Resiliency Plan assets.

requirements in RY1 and RY2 is an increase in net plant investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest) from that currently authorized.[15] For RY1 and RY2, electric net power supply expenses also contribute significantly to the incremental electric revenue requirements over the Two-Year Rate Plan. Other changes impacting the Company's revenue requirement requests relate to regulatory amortizations and increases in distribution, operation and maintenance (O&M), and administrative and general (A&G) expenses for both electric and natural gas operations, compared to current authorized levels.

The Company has included total electric and natural gas pro forma and provisional capital additions planned to transfer-to-plant between July 1, 2023 through December 31, 2025 for RY1, and January 1, 2026 through December 31, 2026 for RY2. The Company pro formed capital additions for the period July 1, 2023 through December 31, 2024. As discussed by Ms. Benjamin, for 2023 and 2024, a level of capital investment through 2024 was approved by the Commission in Dockets UE-220053, et. al., contingent upon the provisional capital review filings in March 2024 for 2023 capital investments and in March 2025 for 2024 capital investments. Capital additions for the period January 1, 2025 through December 31, 2026 are included as "provisional" and subject to further review through the Company's proposed annual Provisional Capital Reporting process as described by Ms. Benjamin.

A few larger projects included by the Company in 2025 impacting the Company's

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[15] The Company typically has approximately 120 Business Cases completed on an annual basis. As discussed by Mr. Christie, for the period 2019 through 2023, our capital expenditures ranged between $425 million and $475 million per year, on a system basis. This level has been increased to $500 million in 2024, $525 million in 2025 and $575 million in 2026, on a system basis.

RY1 increase, as examples, relate to investments in its Wildfire Resiliency Plan, Cabinet Gorge Service Station project, Coyote Springs 2 CT Rotor Replacement project, Gas Aldyl A Pipe Replacement program, Substation Asset Condition/Rebuild projects, Outage Management System & Advanced Distribution Management System (OMS & ADMS) project, and new customer growth investments, to name a few, totaling $232 million alone in 2025 (on a system basis) in gross plant additions. Many of the capital projects are on-going year-to-year and have similar annual investments between 2025 and 2026. As noted by Ms. Benjamin, over 80% of "provisional" investment reflects a continuation of projects already included in 2024 Business Cases. Additional summaries of electric and natural "gross plant" information, as well as "Net Plant after ADFIT" balances are provided below.

Q. In addition to capital investment, would you please identify the main changes in expenses impacting the Company's filed request?

A. The Company has experienced increases in expense, mainly associated with changes in regulatory amortization expense, labor and benefits, Wildfire Resiliency Plan expense, and the significant increases in insurance premiums, mainly due to the impact nationally of wildfires. These increases for RY1 alone, reflect a total of $12.4 million for electric and $3.1 million for natural gas. Other net increases in expenses, such as incremental increases in other O&M expenses to operate Washington's utility operations through 2025, not reflected by those items noted above and prior to offsetting factors included, increased expense approximately $9.3 million for electric and $1.7 million for natural gas. For RY2, incremental increases in O&M/A&G, net of offsets, above RY1 levels, total $5.9 million for electric and $1.1 million for natural gas, mainly due to increases in labor and benefits, property tax, escalated O&M expense and CS2 major maintenance (electric only).

The net change in existing regulatory amortizations compared to current authorized, and new amortizations (i.e. deferrals associated with Wildfire Resiliency, COVID 19, and Washington regulatory fees, etc., totaling \$4.6 million electric and \$0.3 million natural gas in expense) as discussed later in my testimony under Adj. 3.18 – New Regulatory Amortizations, was a total net increase in expense of approximately \$14.6 million for electric and net reduction of \$0.9 million for natural gas.

Finally, Washington electric net power supply expense increased in RY1 approximately \$21.9 million, above prior authorized net power supply costs. However, net offsetting transmission Washington electric revenues also increased approximately \$3.4 million, above prior authorized transmission revenue levels, resulting in an overall net increase to the Company's electric RY1 revenue requirement of \$18.5 million.

In addition, Washington electric net power supply expense increased in RY2 approximately \$59.5 million[16], above RY1 levels, to reflect the mandated removal of Colstrip costs beginning January 1, 2026 as discussed by Mr. Kalich.

Q. With regard to capital investment, please provide additional explanation on the increase in electric and natural gas gross plant investment.

A. The change in gross plant from the historical 12 ME 06.30.2023 test period as noted above for RY1, relates to the 2023 through 2025 capital additions included in this case, and 2026 capital additions for RY2. Table Nos. 2 (electric) and 3 (natural gas) below provide a recap of the Washington "gross plant additions," sponsored by witness, from July

[16] Offsetting this increase are approximately \$35 million system (\$24.4 million Washington share) currently in lower depreciation and fixed O&M costs, as discussed by Ms. Andrews.

1, 2023 through December 31, 2025 for RY1, and January 1, 2026 through December 31, 2026 for RY2, as discussed by Ms. Benjamin.[17]

Table No. 2 – Washington Electric Gross Plant Additions Over Two-Year Rate Plan

Capital Projects - Washington Electric
Gross Transfers To Plant[1]
$ in 000's

Witness	Pro Forma EOP Jul-Dec 2023	Pro Forma EOP 2024	**Pro Forma Total**	Provisional AMA 2025	**Rate Year 1 Total**	Provisional AMA 2026	**Incremental Rate Year 2 Total**	**2-Yr Rate Plan Total**
Mr. Alexander	$ 20,108	$ 22,455	**$ 42,563**	$ 11,868	**$ 54,431**	$ 47,029	**$ 47,029**	**$ 101,460**
Mr. DiLuciano	$ 90,300	$124,470	**$ 214,770**	$ 54,097	**$ 268,867**	$111,645	**$ 111,645**	**$ 380,512**
Mr. Manuel	$ 24,846	$ 28,242	**$ 53,087**	$ 18,539	**$ 71,627**	$ 32,024	**$ 32,024**	**$ 103,651**
Mr. Howell	$ 8,705	$ 21,307	**$ 30,012**	$ 10,025	**$ 40,037**	$ 27,237	**$ 27,237**	**$ 67,274**
Ms. Hydzik	$ 6,403	$ 10,029	**$ 16,431**	$ 1,953	**$ 18,384**	$ 8,794	**$ 8,794**	**$ 27,178**
Total	$ 150,361	$206,502	**$ 356,863**	$ 96,483	**$ 453,346**	$226,729	**$ 226,729**	**$ 680,075**

[1]Excludes impact of retirements, which would lower the overall net plant prior to A/D and ADFIT.

Looking at the changes to "gross" plant-in-service proposed in this filing, as shown in Table No. 2 above, Washington electric RY1 "gross" plant capital additions increase by approximately $453.4 million in RY1 (July 2023 – December 2025 additions) and $226.7 million in RY2 (2026 additions), or $680.1 million over the Two-Year Rate Plan.

[17] Table Nos. 2 and 3 of gross plant additions exclude the impact of retirements. Retirements reduce plant-in-service and A/D by an equal amount, resulting in a net impact of $0 to net plant. Depreciation expense, however, is reduced, resulting in a significant reduction (offset) to the Company's overall revenue requirement related to a reduction in overall depreciation expense, as discussed further below.

Table No. 3 – Washington Natural Gas Gross Plant Additions Over Two-Year Rate Plan

Capital Projects - Washington Natural Gas
Gross Transfers To Plant[1]
$ in 000's

Witness	Pro Forma EOP Jul-Dec 2023	Pro Forma EOP 2024	**Pro Forma Total**	Provisional AMA 2025	**Rate Year 1 Total**	Provisional AMA 2026	**Incremental Rate Year 2 Total**	**2-Yr Rate Plan Total**
Mr. Alexander	$ 4	$ -	**$ 4**	$ -	**$ 4**	$ -	**$ -**	**$ 4**
Mr. DiLuciano	$ 27,643	$ 43,284	**$ 70,927**	$ 17,343	**$ 88,269**	$ 38,111	**$ 38,111**	**$ 126,380**
Mr. Manuel	$ 6,720	$ 7,827	**$ 14,547**	$ 3,479	**$ 18,026**	$ 7,444	**$ 7,444**	**$ 25,470**
Mr. Howell	$ 34	$ 137	**$ 171**	$ 86	**$ 256**	$ 221	**$ 221**	**$ 477**
Ms. Hydzik	$ 1,215	$ 1,941	**$ 3,156**	$ 321	**$ 3,477**	$ 1,733	**$ 1,733**	**$ 5,210**
Total	$ 35,616	$ 53,189	**$ 88,805**	$ 21,229	**$ 110,033**	$ 47,508	**$ 47,508**	**$ 157,542**

[1]Excludes impact of retirements, which would lower the overall net plant prior to A/D and ADFIT.

Looking at the changes to "gross" plant-in-service proposed in this filing, as shown in Table No. 3 above, Washington natural gas RY1 "gross" plant capital additions increase by approximately $110.0 million in RY1 (July 2023 – December 2025 additions) and $47.5 million in RY2 (2026 additions), or $157.5 million over the Two-Year Rate Plan.

As discussed by Ms. Benjamin, the Company has included various restating, pro forma and provisional capital adjustments which incorporate the effects of all capital additions in this case.[18] Other Company witnesses (i.e., Mr. Alexander regarding production assets; Mr. DiLuciano regarding transmission, distribution and general assets; Mr. Manuel regarding the costs associated with Avista's Information Service/Information Technology (IS/IT) projects and short-lived assets; Ms. Hydzik regarding transportation electrification and customer technology projects; and Mr. Howell regarding Wildfire Resiliency Plan

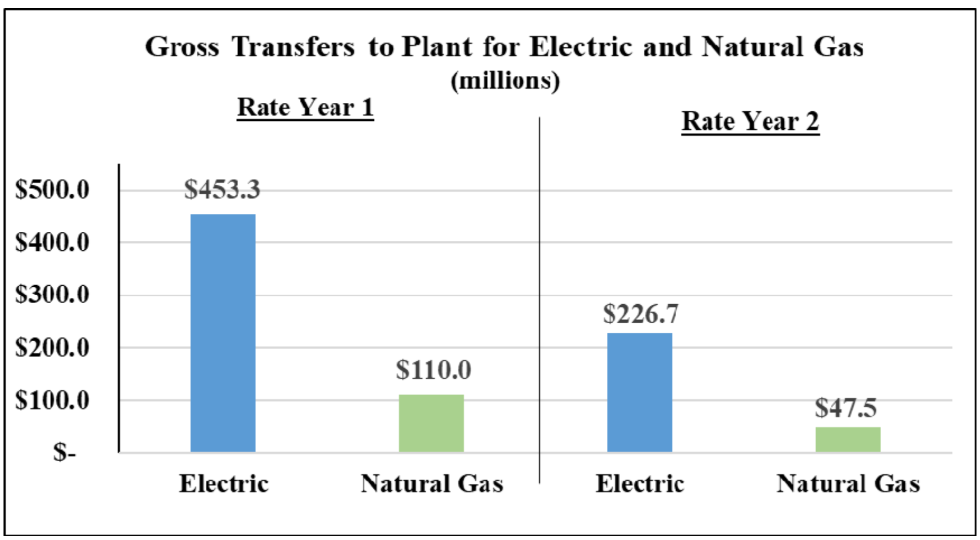
[18] Table Nos. 2 and 3 above reflect Washington electric and natural gas "gross plant" additions in total for the period July 1, 2023 – December 31, 2026. Ms. Benjamin (see Table Nos. 2 through 6 at Exh. TCB-1T) also discusses the specific July 1, 2023 – December 31, 2026 "gross plant" capital additions in more detail by capital witness. In her Table Nos. 4 and 5, she also shows the 2025 - 2026 capital addition adjustments she sponsors by the grouped categories of 1) Short Lived Assets; 2) Programmatic; 3) Mandatory and Compliance; and 4) Large or Distinct. An overall summary of all July 1, 2023 – December 31, 2026 gross capital additions for Washington by electric and natural gas is also provided in Exh. TCB-1T, Table No. 6.

assets), all provide more specific information on the pro forma capital additions (July 2023 through December 2024), as well as, the provisional capital additions (January 2025 through December 2026) included in this case, describing the need for and timing of these capital projects.

Q. Why are the capital additions included in RY1 so much higher than in RY2?

A. RY1 addresses incremental capital deployed in July 1, 2023 through December 31, 2025 (essentially a 2 year period[19]), above current authorized levels, as compared to RY2, which covers 2026 capital additions[20]. Table Nos. 2 and 3 above, can be illustrated (see Illustration No. 4 below) to make that point:

<u>Illustration No. 4 – Washington Electric & Natural Gas Gross Transfers to Plant</u>



The point to remember is that RY1 serves to capture (or "catch up") capital deployed since July 1, 2023. As should be evident, if that capital is not recognized in rates in Rate

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[19] Capital additions included in 2025 are included on an AMA basis, resulting in <u>2 years</u> additions in RY1.
[20] The incremental 2025 balance not in RY1 (since is 2025 AMA) is included in RY2, with 2026 additions included on an AMA basis, essentially resulting in <u>1 year</u> of overall capital additions in RY2.

Year 1, the levels requested and approved in Rate Year 2 will be wholly insufficient.

Q. Taking into consideration these gross plant additions (including retirements), net of accumulated depreciation (A/D) and accumulated deferred federal income taxes (ADFIT), what is the pro forma level of <u>net plant after ADFIT</u> over the Two-Year Rate Plan?

A. Provided in Table No. 4 below is a summary of the "Net Plant after ADFIT" balances over the Two-Year Rate Plan for Washington electric and natural gas for RY1 and RY2. Specifically, Table No. 4 reflects all adjustments impacting the net plant (after ADFIT) for capital additions from July 1, 2023 through December 31, 2025 for <u>RY1,</u> above the 12ME 06.30.2023 AMA test period levels. Incremental adjustments to reflect net plant (after ADFIT) for capital additions from January 1, 2026 through December 31, 2026 are reflected for RY2, above RY1 levels, as shown below:

<u>Table No. 4 – Two-Year Rate Plan - Net Plant After ADFIT Balances for RY1 & RY2</u>

Two Year Rate Plan
Net plant After ADFIT Balances (000s)

Service	Actual 06.2023 Test Period[3]	RY 1 Adjustments	<u>2025</u> RY1 Balances[1]	RY 2 Adjustments	<u>2026</u> RY2 Balances[2]
WA Electric	$ 1,948,790	$ 236,278	$ 2,185,068	$ 93,236	$ 2,278,304
WA Natural Gas	$ 533,429	$ 19,902	$ 553,331	$ 17,089	$ 570,420

[1] See Exh. KJS-2, page 12, row 46 of column "RY1 12.2024 Final Total" for RY1 balances, and Exh. KJS-2, page 14, row 46 of column "RY2 12.2025 Final Total" for RY2 balances.

[2] See Exh. KJS-3, page 12, row 42 of column "RY1 12.2024 Final Total" for RY1 balances, and Exh. KJS-3, page 14, row 42 of column "RY2 12.2025 Final Total" for RY2 balances.

[3] Excludes Colstrip Net Plant After ADFIT, as Colstrip balances are reflected in separate Tariff Schedule 99.

As shown in Table No. 4, for electric, the pro forma net plant after ADFIT for RY1 is adjusted from the 12ME 06.30.2023 test period level[21] of $1,948,790,000 to $2,185,068,000, for a net increase of $236.3 million. For electric RY2, incremental adjustments of $93.2 million above RY1 balances, reflect a total RY2 balance of $2,278,304,000. (See Exh. KJS-2, page 12, row 46, column "RY1 12.2024 Final Total" for RY1 balances and page 14, row 46, column "RY2 12.2025 Final Total" for RY2 balances.)

For natural gas, the pro forma net plant after ADFIT for RY1 is adjusted from the 12ME 06.30.2023 test period level of $533,429,000 to $553,331,000, for a net increase of $19.9 million. For natural gas RY2, incremental adjustments of $17.1 million above RY1 balances, reflect a total balance of $570,420,000 for RY2. (See Exh. KJS-3, page 12, row 42, column "RY1 12.2024 Final Total" for RY1 balances and page 14, row 42, column "RY2 12.2025 Final Total" for RY2 balances.)

As shown in Table No. 5 further below, the revenue requirement in RY1 requested in this case associated with these <u>net capital additions alone</u>, total $36.2 million for electric and $10.0 million for natural gas.[22] Whereas, the incremental revenue requirement for RY2 requested in this case associated with these net capital additions alone, total $12.7 million for electric and $3.4 million for natural gas.[23] As discussed further by Ms. Andrews, and summarized below, depreciation expense and the overall revenue requirement requested by the Company associated with this net plant investment, reflect significant reductions

[21] Actual 12ME 06.30.2023 test period level excludes Colstrip net plant after ADFIT, as Colstrip balances are reflected in separate Tariff Schedule 99.
[22] The revenue requirement included here for RY1 for the pro forma net rate base on capital additions does not include additional capital (January 2023 through June 2023) included in the historical test period (12ME 06.30.2023). This amount also does not include other costs, such as property taxes, or offsetting factors, such as reduced O&M for direct offsets and other revenue.
[23] The revenue requirement included here for RY2 for the pro forma net rate base on capital additions does not include other costs, such as incremental property taxes, or offsetting factors, such as reduced O&M for direct offsets and other revenue.

associated with plant retirements included over the Two-Year Rate Plan (reflecting July 1, 2023 – December 31, 2026 offsets – see Table Nos. 7 and 8).

Q. The Company has included expenses and capital beyond the start of the rate effective date and "through the rate year" for both RY1 and RY2. Can you explain how this has impacted the Company's request for rate relief, and why the levels of costs included by the Company, by rate year, is so important for the Commission to approve?

A. Yes. The Company included plant investment and expenses beyond the rate effective date of late December 2024 for RY1 and late December 2025 for RY2. However, as discussed by Ms. Andrews, the Company also included offsetting factors, including reductions to O&M expenses, plant retirements, growth in revenues, as well as adjusted net plant by A/D and ADFIT through the respective rate effective periods (see Table Nos. 7 and 8). Inclusion of capital, expenses, revenues, and offsetting factors as of the rate effective period for RY1 and RY2, creates a matching of revenues, capital investment and expenses – satisfying the Commission required "matching principle" for approval by this Commission of prudently-incurred costs during the rate-effective periods. If this Commission were to disallow or exclude certain or all costs associated with 2025 (for RY1) and/or 2026 (for RY2), consideration of matched offsetting factors, including O&M offsets and growth revenues for the same periods would have to be excluded as well, in order to also meet the "matching principle." It is important, however, beyond the "matching principle" for this Commission to consider approval of these net expenses, capital investment, revenues and offsetting factors, because without the approval of RY1 and RY2 levels as proposed by the Company, the Company does not have a reasonable opportunity to earn its authorized returns ultimately approved by this Commission in this case.

A. Annual Revenue Requirement by Year: 2023/2024, 2025 and 2026

Q. Please summarize the revenue requirement balances by year included by the Company in its filed case.

A. Included in Table No. 5 below is an approximate reconciliation of net costs by calendar year through 2026. This is approximate, because column "2023/2024" includes approximate incremental increases above test period 12ME 06.30.2023 (and current authorized) levels, representing net costs into RY1, while 2025 includes incremental net costs above 2024 levels expected in RY1. Calendar 2026 reflects incremental net increases in costs above RY1, expected in RY2.

Table No. 5 – Revenue Requirement By Calendar Year

Revenue Requirement By Calendar Year (000s)				
Electric	2023/2024	2025	**2023-2025 RY1**	**2026 RY2**
1) Direct Offsets & Other Revenue[1]	$ (5,428)	$ (4,410)	**$ (9,838)**	**$ (4,366)**
2) Expenses/Other	$ 17,811	$ 14,380	**$ 32,191**	**$ 10,260**
3) Capital[2]	$ 28,267	$ 7,941	**$ 36,208**	**$ 12,724**
4) Power Supply/Transmission[3]	$ -	$ 18,506	**$ 18,506**	**$ 59,512**
Total	$ 40,650	$ 36,417	**$ 77,067**	**$ 78,130**
Natural Gas	2023/2024	2025	**2023-2025 RY1**	**2026 RY2**
1) Direct Offsets & Other Revenue[1]	$ (848)	$ (530)	**$ (1,378)**	**$ (362)**
2) Expenses/Other	$ 5,757	$ 2,969	**$ 8,726**	**$ 1,494**
3) Capital[2]	$ 7,366	$ 2,579	**$ 9,945**	**$ 3,432**
Total	$ 12,276	$ 5,017	**$ 17,293**	**$ 4,564**

[1]Line 1) Direct Offsets and Other Revenue includes direct O&M expense offsets, as well as Growth revenue. See EMA-1T, Table Nos. 4 and 5 for offset values.

[2]Line 3) Capital includes offsets associated with retirements (reductions to depreciation expense), as well as impacts on existing net plant for A/D and ADFIT through RY1 and RY2. See EMA-1T, Table Nos. 4 and 5 for offset values.

[3]Line 4) Power Supply/Transmission includes net power supply expense & transmission revenues in ERM baseline.

It is important to note that item 1) Direct Offsets & Other Revenue, for each period shown in Table No. 5 above, reflect only the incremental direct O&M and offsetting growth revenues. Line 1) does not reflect incremental offsets included in the Company's case related to plant retirements (reduced depreciation expense), reductions to 06.2023 existing plant for A/D and ADFIT to RY1 and RY2 levels (reducing net plant after ADFIT), which are consolidated in Line 3) Capital, for purposes of Table No. 5. Table Nos. 7 (electric) and 8 (natural gas) below, recreated from Ms. Andrews' Table Nos. 6 and 7, provide a full reconciliation of all offsets included by the Company over the Two-Year Rate Plan.

With regards to RY2, the majority of the incremental increase in Washington electric revenue requirement is associated with changes in net power supply costs of approximately $59.5 million, as shown in Table No. 6 below. As discussed above, RY2 is offset by the mandated removal of certain Colstrip costs by January 1, 2026 currently included in Colstrip Tariff Schedule 99 of $24.4 million, resulting in a net bill increase to customers of $53.7 million.

Table No. 6 – Breakdown of Washington Electric RY2 Revenue Requirement

Breakdown of Washington Electric RY2 Revenue Requirement ($000s)		
Net Expense/Capital Investment Increase	$	18,618
Colstrip Power Supply Increase	$	59,512
Subtotal - Base Rate Increase	$	78,130
Schedule 99 Colstrip Tracker Reduction	$	(24,419)
Overall Bill Impact	**$**	**53,711**

B. Offsetting Factors

Q. Please summarize the Washington electric and natural gas offsetting factors included by the Company in its filed case and sponsored by Ms. Andrews.

A. As discussed by Ms. Andrews, the Company has included in its electric and natural gas Pro Forma Studies, total O&M offsets, other revenue, retirements (reduced depreciation expense), and reduced net plant after ADFIT for the change in A/D and ADFIT on existing plant at 06.2023, adjusted to AMA 2025 for RY1 and AMA 2026 for RY2.

Table Nos. 7 and 8 below, duplicated from Ms. Andrews' testimony (at Exh. EMA-1T, Table Nos. 6 and 7), shows a reconciliation of the total Washington electric and natural gas offsetting factors, by year, included by the Company in its filed case, as described by Ms. Andrews.

Table No. 7 – Washington Electric Total Offsetting Factors

Total Two-Year (RY1 & RY2) Incremental Offsets - Washington Electric (Revenue Requirement Values)						
Electric (000s)	**2023/2024**	**2025**	**2023-2025 RY1**	**2026 RY2**	**Two-Year (RY1 & RY2) Totals**	**Electric Adjustments**
1) **Direct O&M Offsets & Other Revenue**	**$ (5,428)**	**$ (4,410)**	**$ (9,838)**	**$ (4,366)**	**$ (14,204)**	
a) Direct O&M Offsets[1]	$ (1,892)	$ (1,247)	$ (3,139)	$ (1,202)	$ (4,341)	3.04, 4.02, 5.01, 5.08
b) Other Revenue (Growth)	$ (3,536)	$ (3,163)	$ (6,699)	$ (3,164)	$ (9,863)	4.02, 5.08
2) **Depreciation Expense (Retirements)**	**$ (10,520)**	**$ (7,563)**	**$ (18,083)**	**$ (7,457)**	**$ (25,540)**	3.15, 3.17, 4.01, 5.07
3) **Revenue Requirement of A/D and ADFIT[2]**	**$ (16,645)**	**$ (4,944)**	**$ (21,589)**	**$ (8,310)**	**$ (29,899)**	
Total Revenue Requirement Impact	**$ (32,593)**	**$ (16,917)**	**$ (49,510)**	**$ (20,133)**	**$ (69,643)**	
[1]Direct O&M Offsets include new investment O&M offsets, 2% efficiency O&M adjustment and AMI O&M offset.						
[2]Revenue requirement based on reduction to A/D and ADFIT on existing (06.2023) plant as follows:	$ (177,152)	$ (52,620)	$ (229,772)	$ (88,439)	$ (318,211)	3.15, 3.17, 4.01, 5.07

As noted in Table No. 7, the row "Total Revenue Requirement Impact," combining all adjustments (Lines 1-3), results in an overall reduction to the Company's Washington electric revenue requirement of $49.5 million for RY1, $20.1 million for RY2, and a Two-Year Total of $69.6 million.

Table No. 8 – Washington Natural Gas Total Offsetting Factors

Total Two-Year (RY1 & RY2) Incremental Offsets - Washington Natural Gas (Revenue Requirement Values)						
Natural Gas (000s)	**2023/2024**	**2025**	**2023-2025 RY1**	**2026 RY2**	**Two-Year (RY1 & RY2) Totals**	**Natural Gas Adjustments**
1) **Direct O&M Offsets & Other Revenue**	**$ (848)**	**$ (530)**	**$ (1,378)**	**$ (362)**	**$ (1,740)**	
a) Direct O&M Offsets	$ (631)	$ (385)	$ (1,016)	$ (321)	$ (1,337)	3.04, 4.02, 5.01, 5.08
b) Other Revenue (Growth)	$ (217)	$ (145)	$ (362)	$ (41)	$ (403)	4.02, 5.08
2) **Depreciation Expense (Retirements)**	**$ (1,578)**	**$ (1,000)**	**$ (2,578)**	**$ (872)**	**$ (3,450)**	3.15, 3.17, 4.01, 5.07
3) **Revenue Requirement of A/D and ADFIT**[1]	**$ (4,115)**	**$ (1,193)**	**$ (5,307)**	**$ (1,948)**	**$ (7,255)**	
4) **Total Revenue Requirement Impact**	**$ (6,540)**	**$ (2,723)**	**$ (9,263)**	**$ (3,183)**	**$ (12,445)**	
[1]Direct O&M Offsets include new investment O&M offsets, 2% efficiency O&M adjustment and AMI O&M offset.						
[2]Revenue requirement based on reduction to A/D and ADFIT on existing (06.2023) plant as follows:	$ (43,800)	$ (12,695)	$ (56,495)	$ (20,740)	$ (77,235)	3.15, 3.17, 4.01, 5.07

As noted in Table No. 8, the row "Total Revenue Requirement Impact," <u>combining all adjustments (Lines 1-3), results in an overall reduction to the Company's Washington natural gas revenue requirement of $9.3 million for RY1, $3.2 million for RY2, and a Two-Year Total of $12.5 million</u>.[24]

Q. Company witness Mr. Christie discusses the Company's recent history and need for new capital investment, as well as the Company's planned investment through 2026. What conclusions can be drawn regarding the increased capital investment, as well as related increased expenses, included by the Company for RY1 and RY2?

A. As described in Mr. Christie's testimony, Avista is making significant capital investments in our natural gas distribution system, electric generation, transmission and distribution facilities, and new technology to better serve the needs of our customers. These

[24] As discussed by Ms. Andrews, at Exh. EMA-3 ("Direct and Indirect – Offsets Matrix" (hereafter "Matrix")), are each of the "direct" offsets (as well as any "indirect" offsets) descriptions, and the "2% Efficiency Adjustment" calculated on investments, where applicable, by each Business Case included by the Company over its Two-Year Rate Plan for investments from 2024 through 2026. Each separate Business Case (see Sections 2.3 - 2.4 "direct" and "indirect" offsets), are provided by each capital witness, i.e., Mr. Alexander at Exh. AGA-2; Mr. DiLuciano at Exh. JDD-2; Mr. Manuel at Ex. WOM-2; Ms. Hydzik at Exh. NLH-2; and Mr. Howell at Exh. DRH-2.

investments are focused on, among other things, the preservation and enhancement of safety, service reliability and the replacement of aging infrastructure.

For the period 2019 through 2023, our capital expenditures ranged between $425 million and $475 million per year, on a system basis (i.e., Washington, Idaho, and Oregon, electricity, and natural gas). Avista's plans continue to call for making significant utility capital investments in our electric and natural gas systems to preserve and enhance service reliability for our customers, including the continued replacement of aging infrastructure. Capital expenditures of approximately $500-$575 million per year, on a system basis, are planned for the three-year period ending December 31, 2026. As noted by Mr. Christie, Avista needs adequate cash flow from operations to fund these requirements, together with access to capital from external sources under reasonable terms, on a sustainable basis.

As noted by Ms. Benjamin, as Avista removes old equipment and replaces it with new, the depreciation component currently included in retail rates generally covers only a very small amount of the new facilities and equipment placed into service, especially for the long-lived assets. Avista's retail rates are cost-based, which means the prices customers are paying today for natural gas pipe, gate stations, transformers, distribution poles, substations, and transmission lines, among other facilities, are based on the cost to install those facilities, in some cases, 40, 50, and even 60 years ago. The costs of the same equipment and facilities today are many times more expensive. The depreciation component built into retail rates today is based on the much lower cost to install those facilities many years ago. Therefore, the depreciation component in retail rates covers only a small fraction of the annual costs associated with the new investment in facilities.

Furthermore, as plant is completed and is providing service to customers, it is important for this new investment, as well as the expenses supporting that investment, be reflected in retail rates in a timely manner. As discussed by Mr. Vermillion, in any multiyear rate plan, the first-year revenue requirement approved by the Commission will persist for each year of the rate plan and is the basis for additional revenue adjustments in year 2, 3 and beyond. If the new investment and related expenses pro formed by the Company over the proposed Two-Year Rate Plan in this case are not included, significant regulatory lag will persist year-after-year, having a negative impact on Avista's earnings. It is essential, therefore, for this Commission to approve sufficient capital investments and expenses in RY1 and RY2 as proposed by the Company, if the Company has any opportunity to earn its allowed rates of return during the approved Two-Year Rate Plan.

SECTION 2 – DERIVATION OF TWO-YEAR RATE PLAN PRO FORMA STUDIES

V. DERIVATION OF ELECTRIC AND NATURAL GAS TWO-YEAR RATE PLAN PRO FORMA STUDIES

Q. Please explain what is shown in the electric and natural gas Two-Year Pro Forma Studies, provided as Exh. KJS-2 and Exh. KJS-3.

A. Exh. KJS-2 (electric) and Exh. KJS-3 (natural gas) show actual and pro forma electric and natural gas operating results and rate base for the pro forma test period for the State of Washington. Exh. KJS-4 provides the service and jurisdiction allocation methodologies used by the Company in preparation of its Washington jurisdiction electric and natural gas Pro Forma Studies.[25]

[25] The Company directly assigns costs when appropriate. Costs not specifically identifiable to a specific jurisdiction are allocated in accordance with an approved allocation procedure. This process designates costs as common to all services and jurisdictions (CD.AA), common to electric operations only (ED.AN), common to natural gas operations in Washington and Idaho only (GD.AN), or common to natural gas operations only (GD.AA).

Specifically, page 1, of both Exh. KJS-2 and Exh. KJS-3, Column (b), shows 12ME 06.2023 actual operating results and components of the average-of-monthly-average rate base as recorded[26]; column (c) shows total restated adjustments to actual net operating income and rate base; (d) shows the Restated Results Total (actual results reflecting all restating adjustments); (e) is the total of all pro forma adjustments to net operating income and rate base for RY1; and column (f) is Pro Forma results of operations for RY1, all under existing rates. Column (g) shows the RY1 revenue increase required which would allow the Company to earn a 7.61% rate of return. Column (h) reflects pro forma operating results for RY1 with the requested increase of $77,067,000 for electric and $17,293,000 for natural gas.

Page 2 of both Exh. KJS-2 and Exh. KJS-3, show similar columns starting with column (b) that includes RY1 pro forma results (equal to column (f) on page 1 of Exh. KJS-2 and Exh. KJS-3), reflecting operating results and components of rate base for RY1 results. Column (c), of page 2, is the total of all adjustments to net operating income and rate base to reflect RY2 results; and column (d) is the RY2 (12.2025 effective) pro forma results of operations, all under existing rates. Column (e) and (f) shows the revenue increases required in RY1 and RY2 to allow the Company to earn a 7.61% rate of return for RY2. Column (g) reflects RY2 pro forma operating results with the requested increases of $78,130,000 for electric and $4,564,000 for natural gas, above that requested in RY1.

[26] Actual plant rate base (cost, A/D and ADFIT) uses the 12ME 06.30.2023 AMA balances. Plant rate base is first restated (restated adjustment) to a 12ME 06.30.2023 End-of-Period (EOP) rate base, and then further adjusted (pro forma adjustments) to 12ME 12.31.2024 EOP. These pro forma adjustments include capital projects completed and transferred to plant during July 1, 2023 through December 31, 2024, as well as the impacts of the Company's latest depreciation study with new depreciation rates effective January 1, 2024 as approved in Docket Nos. 230123 and 230130, Order 01. As discussed above, beyond December 31, 2024, provisional adjustments are included for capital additions from January 1, 2025 through December 31, 2025 for RY1, and January 1, 2026 through December 31, 2026 for RY2.

Q. What does page 3 of Exhs. KJS-2 and KJS-3 show?

A. Page 3 of Exh. KJS-2 shows the RY1 and RY2 revenue requirement calculations for electric of $77,067,000 and $78,130,000, respectively, at the requested 7.61% rate of return. This page also shows the percentage base revenue increase for electric RY1 and RY2, of 13.0% and 11.7%, respectively. Percentages on a billed basis for electric RY1 is 12.6%, and RY2 is 7.8%, after taking into account the mandated removal of certain Colstrip costs effective January 1, 2026 currently included in Colstrip Tariff Schedule 99.

Page 3 of and Exh. KJS-3 (natural gas) shows the RY1 and RY2 revenue requirement calculations for natural gas of $17,293,000 and $4,564,000, respectively, at the requested 7.61% rate of return. This page also shows the percentage base revenue increase for natural gas RY1 and RY2, of 13.6% and 3.2%, respectively. Percentages on a billed basis for natural gas are 6.3% and 1.6%.

Q. What does page 4 of Exhs. KJS-2 and KJS-3 show?

A. Page 4, of both Exhs. KJS-2 and KJS-3 shows the Cost of Capital and Capital Structure included in the Pro Forma Studies, including: 1) 48.5% Common Equity / 51.5% Debt capital structure; 2) Return on Equity of 10.40%; and 3) cost of debt of 4.99%, resulting in an overall Rate of Return (weighted average cost of capital) of 7.61%. Mr. Christie discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while Company witness Mr. McKenzie provides additional testimony related to the appropriate return on equity for Avista. Both Mr. Christie and Mr. McKenzie also address the incremental 8 basis points (.08%) included in the Company's ROE to reflect flotation costs.[27]

Q. Would you now please explain page 5 of Exh. KJS-2 and Exh. KJS-3?

A. Yes. Page 5 shows the derivation of the net-operating-income-to-gross-revenue-conversion factor. The conversion factor reflects uncollectible accounts receivable, Commission fees and Washington State excise taxes. Federal income taxes are reflected at 21%.

Q. Turning to pages 6 through 14 of Exh. KJS-2 and Exh. KJS-3, would you please explain what those pages show?

A. Yes. Page 6 of both Exh. KJS-2 and Exh. KJS-3 begins with actual operating results and rate base for the 12ME 06.30.2023 test period on an AMA basis in column (1.00). Individual normalizing and restating adjustments that are standard components of our annual reporting to the Commission begin in column (1.01) on page 6 and continue through column (2.19) on page 8 for electric, and column (2.15) on page 8 for natural gas.

For electric, for RY1, Exh. KJS-2, individual pro forma adjustments begin in column (3.00P) on page 9 and continue through column (3.24) on page 12, and provisional adjustments begin in column (4.01) and continue through column (4.02) on page 12. The

[27] An increase in ROE of eight basis points (0.08%) to reflect flotation costs, increases the Company's proposed revenue requirement requested in this case for Washington electric by $921,000 in RY1 and $36,000 in RY2, and for Washington natural gas by $234,000 in RY1 and $7,000 in RY2. This total of $1,198,000 over the Two-Year Rate Plan for Washington operations is reasonable, and as explained by Mr. Christie, is representative of the annual costs unrecovered elsewhere for sale agent fees, registration fees and legal expenses incurred when the Company issues equity. For example, for 2023, as of September 30, 2023, the Company had incurred $1.3 million in flotation costs. These costs have ranged as high as $1.8 million in recent years. Flotation costs are not recorded on the income statement and are not included in the cost of capital. Common equity raised through the sale of stock is recorded net of these costs. Mr. McKenzie also explains that there are further opportunity costs associated with issuing equity and flotation costs related to the overall cost of equity.

final column on page 12 includes the "RY1 12.2024 FINAL TOTAL" representing the total pro forma operating results and net rate base for the RY1 pro forma period.

Electric RY2 adjustments begin on page 13 through 14 of Exh. KJS-2, and include all electric individual pro forma / provisional adjustments, in columns (5.00P) through column (5.12). The final columns on page 14 include the "RY2 12.2025 FINAL TOTAL" and "RY2 INCREMENTAL 12.2025-I FINAL TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period, and the incremental balances above the RY1 pro forma rate year.

For natural gas, for RY1, Exh. KJS-3, individual pro forma adjustments begin in column (3.01) on page 9 and continue through column (3.20) on page 12, and provisional adjustments begin in column (4.01) through column (4.02) on page 12. The final column on page 12 includes the "RY1 12.2024 FINAL TOTAL" representing the total pro forma operating results and net rate base for the RY1 pro forma period.

Natural Gas RY2 adjustments begin on page 13 through 14 of Exh. KJS-3, and includes all natural gas individual pro forma / provisional adjustments, in columns (5.01) through column (5.08). The final columns on page 14 include the "RY2 12.2025 FINAL TOTAL" and "RY2 INCREMENTAL 12.2025-I FINAL TOTAL" columns, representing the total pro forma operating results and net rate base for the RY2 pro forma period, and the incremental balances above the RY1 pro forma rate year.

Q. Please now turn to the final page of Exh. KJS-2 and KJS-3, and describe this page.

A. The last page, page 15 of Exh. KJS-2 and Exh. KJS-3, provides a one-page summary list of all RY1 and RY2 restating, pro forma and provisional adjustments, by adjustment number and description, with individual NOI, rate base and revenue requirement amounts, as well as overall NOI, rate base and revenue requirement balances, and the rates of return on an actual, restated and pro forma levels, for RY1 and RY2 for ease of reference.

The testimony that follows explains the reason and theory for each of the electric and natural gas Commission Basis, restating, pro forma and provisional adjustments, as well as the calculation, where appropriate. These adjustments were prepared consistent with current regulatory principles and the manner in which they have been addressed in recent cases (i.e., Dockets UE-200900, et. al., and UE-220053, et. al.), unless otherwise noted. The Company has also provided Exh. KJS-2 (Electric) and Exh. KJS-3 (Natural Gas) in native format, providing supporting information and calculation tabs by adjustment, which link to each adjustment column provided on pages 6 – 14 of Exh. KJS-2 and KJS-3. Finally, the Company will provide workpapers in electronic format, which include additional details and calculations related to each of these adjustments to all Parties after the filing of this case.

VI. STANDARD COMMISSION BASIS AND RESTATING ADJUSTMENTS

Q. Please explain each of the Commission Basis and restating adjustments included, starting on page 6 of both Exh. KJS-2 and Exh. KJS-3, the reason for the adjustment and its effect on the Washington electric and natural gas net operating income and/or rate base for the historical test period.

A. Starting on page 6 of Exh. KJS-2 and Exh. KJS-3, Column (1.00) the **Results of Operations** reflect the Company's actual operating results and total net rate base experienced by the Company for year ending June 30, 2023, on an AMA basis. Columns following the Results of Operations column (1.00), (columns (1.01) – (2.19) for electric and columns (1.01) – (2.15) for natural gas) mainly reflect normalizing and restating adjustments necessary to restate the actual results based on prior Commission orders, reflect appropriate annualized expenses, correct for errors, or remove prior period or non-recurring amounts reflected in the year ending June 30, 2023.[28] A summary of each adjustment follows:

The first column on page 6, Electric Adjustment (1.01) and Natural Gas Adjustment (1.01), entitled **<u>Deferred FIT Rate Base,</u>** adjusts the electric and natural gas accumulated deferred federal income tax (ADFIT) rate base balance included in the Results of Operations column (1.00) to the adjusted ADFIT balance reflected on an AMA basis, as shown within supporting information provided with the Company's filing and supporting workpapers. ADFIT reflects the deferred tax balances arising from timing differences between book recognition and tax recognition of certain income and deductions. The primary deductions that have timing differences, and therefore associated ADFIT, are accelerated tax depreciation over book depreciation and the repairs deduction.

The effect of these adjustments on Washington rate base is an increase of $2,942,000 for electric and a reduction of $224,000 for natural gas. The effect of this change to net operating income (NOI), due to the Federal Income Tax (FIT) expense on the restated level of interest on the change in rate base, is an increase of $16,000 for electric and a reduction of $1,000 for natural gas.[29]

The next column on page 6, Electric Adjustment (1.02) and Natural Gas Adjustment

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[28] Included with the electric and natural gas restating adjustments is an End-Of-Period (EOP) 06.30.2023 Net Plant adjustment, adjusting net plant from an average-of-monthly-average (AMA) 06.30.2023 historical test year balance to a 06.30.2023 EOP net plant historical test-year balance, similar to that approved by the WUTC in Avista's last litigated general rate case proceeding (Dockets UE-200900 et. al.) and Dockets UE-220053, et. al.

[29] The net effect of Federal Income Tax (FIT) expense on the restated level of interest expense due to a change in rate base, is shown within <u>each</u> individual adjustment. The debt interest impact per individual rate base adjustment can be seen on line 28, pages 6-14 of Exhs. KJS-2 and KJS-3.

(1.02) - **<u>Deferred Debits and Credits,</u>** is a consolidation of previous Commission Basis or other restating rate base adjustments and their NOI impact. The net impact on a consolidated basis of this adjustment has no impact on either Washington electric or natural gas rate base or NOI.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 12ME 06.30.2023 actual results (included in column 1.00 "Per Results of operations"), based on prior Commission orders, and are explained below.

The following items are included in the consolidated adjustment:

- **<u>Restating Montana Riverbed Lease (Electric)</u>** reflects the costs associated with the Montana Riverbed lease settlement. In this settlement, the Company agreed to pay the State of Montana $4.0 million annually beginning in 2007, with <u>annual inflation adjustments</u>, for a 10-year period for leasing the riverbed under the Noxon Rapids Project and the Montana portion of the Cabinet Gorge Project. The first two annual payments were deferred by Avista as approved in Docket UE-072131. In Docket UE-080416 (see Order No. 08), the Commission approved the Company's accounting treatment of the deferred payments, including accrued interest, to be amortized over the remaining eight years of the agreement starting on January 1, 2009. The 10-year amortization of the first two annual payment deferral expired on December 31, 2016, therefore there is no rate base balance. The lease continues on a year-to-year basis adjusted for annual inflation, with payments being paid into escrow until resolution of pending litigation. No adjustment from that recorded within results of operations is necessary, as the annual lease expense is correctly recorded.

- **<u>Customer Advances (Electric and Natural Gas)</u>** decreases rate base for money advanced by customers for line extensions, as they will be recorded as contributions-in-aid-of-construction at some future time. This adjustment is a component of the actual results of operations.

- **<u>Customer Deposits (Electric and Natural Gas)</u>** reduces electric and natural gas rate base by the average-of-monthly-averages of customer deposits held by the Company, as ordered by this Commission in Dockets UE-090134 and UG-090135. No adjustment to Washington electric or natural gas rate base from that recorded within results of operations is necessary, as the level of rate base is correctly recorded. The corresponding interest paid on customer deposits is reclassified to utility operating expense, at the current UTC interest rate of 4.67%. The change in expense was immaterial for both Washington electric (increase of $217) and natural gas (increase of $64), resulting in no impact to expense.

In summary, as noted above, the net impact on a consolidated basis of the adjustments described above have no impact on either Washington electric or natural gas rate base or NOI, as the level included in Results of Operations was recorded correctly. (Electric and Natural Gas Adjustment (3.02) Pro Forma Deferred Debits, Credits & Regulatory Amortizations, explained below, adjust certain items listed above to reflect RY1 pro forma rate period result levels of deferred debits and credit balances and amortization expense as ordered in prior cases.)

Continuing on page 6 of Exh. KJS-2 and KJS-3, column (1.03) **Working Capital -** electric and natural gas working capital is included in the Company's Results of Operations column (1.00) on a 12ME 06.30.2023 test period AMA basis. The Company uses the Investor Supplied Working Capital (ISWC) methodology to calculate the amount of working capital reflected in its actual results of operations. This method is consistent with that approved by the Commission in the Company's last electric and natural gas litigated general rate cases, Dockets UE-200900 et. al. To properly reflect the working capital balance based on the method approved in Dockets UE-200900 et. al., an adjustment to electric and natural gas working capital rate base is necessary from that recorded within results of operations. The impact of this adjustment reduces rate base $3,239,000 for electric and $648,000 for natural gas. The impact to NOI is a reduction of $17,000 for electric and $3,000 for natural gas.

Remove Colstrip (Electric), column (1.04), as sponsored by Ms. Andrews, reflects the removal from actual 12ME 06.30.2023 test period balances of the Company's Colstrip

Unit 3 and Unit 4 costs (exclusive of transmission investment and those costs included in the Energy Recovery Mechanism (ERM)), including operating and maintenance (O&M) and other expenses, depreciation expense, decommissioning and remediation (D&R) costs, and return on rate base. These costs are recovered from customers through separate Tariff Schedule 99 "Colstrip Tracker."[30] Therefore, these Colstrip costs are not included in base rates, and must be excluded from the Company's 12ME 06.20.2023 test period results to determine RY1 expense and rate base levels. The effect of this adjustment decreases Washington electric rate base $24,878,000, revenues by $22,988,000, net expenses by $21,027,000, and net operating income (NOI) by $1,683,000, resulting in a net reduction to Washington electric revenue requirement of $279,000.

Eliminate B & O Taxes, column (2.01) electric and natural gas, eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Washington customers. The adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. B & O taxes are passed through on a separate schedule, which is not part of this proceeding. The effect of this adjustment is to increase Washington electric and natural gas NOI by $51,000 and $33,000, respectively.

Restate Property Tax, column (2.02) electric and natural gas, restates accrued property tax during the test period to actual property tax paid during the 12ME June 30, 2023. The effect of this adjustment decreases Washington electric NOI by $1,073,000 and natural gas NOI by $228,000. As explained below, Adjustment (3.11) Pro Forma Property

[30] The Company was required to remove Colstrip Unit 3 and Unit 4 costs (exclusive of transmission investment and those costs included in the ERM) from base rates, and separately track these costs through Tariff Schedule 99 "Colstrip Tracker" per Dockets UE-220053, et. al.

Tax adjusts property tax expense to reflect the levels of expense expected during RY1, and Adjustment (5.04) Pro Forma Property Tax adjusts property tax expense to reflect the levels of expense expected during RY2.

Uncollectible Expense, column (2.03) electric and natural gas, restates accrued test period expense levels for uncollectible expense at June 30, 2023, to the actual level of net write-offs less the deferred COVID-19 net benefits and expenses (including bad debt expense) for the test period. The effect of this adjustment decreases Washington electric NOI by $720,000, and Washington natural gas NOI by $732,000.

Regulatory Expense, the last adjustment on page 6, column (2.04) electric and natural gas, restates recorded regulatory expense for 12ME June 30, 2023, to reflect the UTC assessment rates applied to revenues for the test period, and for electric, the actual levels of FERC fees paid during the test period. The effect of this adjustment decreases Washington electric NOI by $659,000, and Washington natural gas NOI by $314,000.

Q. Please turn to page 7 of Exh KJS-2 and Exh. KJS-3 and explain the adjustments shown there.

A. Turning to page 7 of Exh. KJS-2 and Exh. KJS-3, the first adjustment in column (2.05) **Injuries and Damages**, restates electric and natural gas accrued injuries and damages expense with a six-year rolling average of injuries and damages payments not covered by insurance. As a result of the Commission's Order in Docket U-88-2380-T, the Company changed to the reserve method of accounting for injuries and damages not covered by insurance. The Commission reaffirmed this methodology in Order 08/05 in Dockets UE-200900 et. al. The effect of this adjustment increases Washington electric NOI by $249,000, and natural gas NOI by $14,000.

FIT/DFIT/ITC Expenses, column (2.06) electric and natural gas, reflects the appropriate level of FIT and DFIT expense for the year ending June 30, 2023. Test period results for FIT uses taxable income (jurisdictional results adjusted for Schedule M adjustments) calculated at the 21% federal income tax rate. DFIT expenses include federal taxes for normalized and flow-through federal tax adjustments. In addition, for electric, the income tax expense reflects the appropriate level of investment tax credits (ITC) on qualified electric generation. The FIT and DFIT adjustment required to reflect the appropriate Washington electric and natural gas balances, increases NOI by $209,000 for electric, and $101,000 for natural gas.

Office Space Charged to Non-Utility, column (2.07) electric and natural gas, removes a portion of electric and natural gas office space costs[31] based on the relationship of labor hours charged to subsidiary/non-utility activities by employee compared to total labor hours by employee. These percentages are applied to the employees' office space (expressed in square feet) and multiplied by office space costs/per square foot. This restating adjustment is made as a result of the Commission's Third Supplemental Order in Docket U-88-2380-T and removes the portion of electric and natural gas expense that has not already been reflected in the Test Period as non-utility. The effect of this adjustment increases Washington electric and natural gas NOI by $26,000 and $8,000, respectively.

Restate Excise Taxes, column (2.08) electric and natural gas, removes the effect of a one-month lag between collection and payment of electric and natural gas taxes. The effect of this adjustment increases Washington electric and natural gas NOI by $46,000 and

[31] Office space is comprised of office building operating and fixed costs, utilities, administrative, security, HVAC, depreciation and property taxes, as well as other costs related to employee use of phones, laptops, etc.

$3,000, respectively.

<u>Net Gains/Losses</u>, column (2.09) electric and natural gas, reflects a ten-year amortization of net gains realized from the sale of real property disposed of between 2011 and June 30, 2023. This restating adjustment is made as a result of the Commission's Order in Dockets UE-050482 and UG-050483. The effect of this adjustment increases electric and natural gas NOI by $54,000 and $9,000, respectively.

<u>Weather Normalization (Electric)</u>, column (2.10) for electric, normalizes weather sensitive kWh sales by eliminating the effect of temperature deviations above or below historical norms. Company witness Mr. Garbarino is sponsoring this adjustment. The effect of this adjustment decreases NOI by $1,101,000.

<u>Weather Normalization & Gas Cost Adjustment (Natural Gas)</u>, column (2.10), normalizes weather sensitive gas therm sales by eliminating the effect of temperature deviations above or below historical norms. This adjustment also restates therms sold to reflect the weather normalized therms and then reprices the adjusted therms sold based upon the authorized weighted average cost of gas. Company witness Mr. Anderson is sponsoring this adjustment. The effect of this adjustment decreases NOI by $34,000.

<u>Eliminate Adder Schedule Adjustments</u>, column (2.11) electric and natural gas, removes the impact of the electric and natural gas adder schedule revenues and related expenses which are recovered/rebated by separate tariffs and, therefore, are not a part of base rates. For electric, rate schedules such as Schedule 59 Residential Exchange credit, Schedule 75 Decoupling Rebate/Surcharge, Schedule 76 Customer Tax Credit, Schedule 78 Residual Customer Tax Credit, Schedule 88 Wildfire Resiliency, Schedule 89 Fixed-Income Senior & Disabled Residential Service Discount Rate Adjustment, Schedule 91 Tariff Rider

(DSM), Schedule 92 Low Income Rate Assistance Program Rate, Schedule 93 ERM rebate, Schedule 95 Optional Renewable and Schedule 98 REC Revenue Surcharge/Rebate are removed. For natural gas, rate schedules such as Schedule 150 Purchased Gas Cost Adjustment, Schedule 155 Gas Cost Amortization surcharge/rebate, Schedule 175 Decoupling Rebate/Surcharge, Schedule 176 Customer Tax Credit, Schedule 178 Residual Customer Tax Credit, Schedule 189 Fixed-Income Senior & Disabled Residential Service Discount Rate Adjustment, Schedule 191 Tariff Rider (DSM), Schedule 192 Low Income Rate Assistance Program Rate and Schedule 195 Optional Renewable are removed. In addition, various accounts associated with the cost of natural gas managed through the PGA deferral mechanism are consolidated into City Gate Purchases in this adjustment.

Mr. Garbarino (electric) and Mr. Anderson (natural gas) sponsor these two adjustments. The removal of most schedules reflects expense that is equal to the adjustment to revenue. However, for both electric and natural gas, the removal of Schedules 76/176 Customer Tax Credit, Schedules 78/178 Residual Customer Tax Credit, and Schedule 95/195 Optional Renewable revenues and expenses have the effect of increasing electric and natural gas NOI by $2,000 and $8,000, respectively.

Q. Please explain the final adjustment on page 7 of Exh. KJS-2 and the first adjustment on page 8 of Exh. KJS-3.

The final adjustment on page 7 of Exh. KJS-2 and the first adjustment on page 8 of Exh. KJS-3 is **<u>Miscellaneous Restating Non-Utility/Non-Recurring Expenses</u>,** column (2.12) electric and natural gas. This adjustment removes a number of expenses reclassed to non-utility from the Company's electric and natural gas test period actual results, and removes, reclassifies or restates other expenses incorrectly charged between service and/or jurisdiction. In addition, the Company has removed or restated certain Director and Officer related expenses per Dockets UE-090134 and UG-090135. Specifically, director fees and director meeting expenses were reduced by a net $557,000 electric and $176,000 natural gas expense to reflect 50% of overall expenses in utility operations, and the Company has also removed 10% of total Directors' and Officers' insurance expense to reflect the non-utility/subsidiary portion. Finally, the Company has also removed the utility-portion of the Company's Long-Term Incentive Plan (LTIP) related to restricted shares expense, as ordered in Dockets UE-150204 and UG-150205, in the amount of $665,000 electric and $211,000 natural gas expense.[32] The net reduction of these expenses for electric and natural gas is approximately $1,297,000 and $415,000, respectively. Therefore, the overall <u>net</u> impact of this adjustment increases electric NOI by $1,025,000 and natural gas NOI by $328,000.

Q. Please continue an explanation for adjustments on page 8.

A. The first adjustment on page 8 of Exh. KJS-2 and the second adjustment on page 8 of Exh. KJS-3 is **<u>Restating Incentive Expense</u>,** column (2.13) electric and natural gas. This adjustment restates actual O&M incentive compensation expense recorded for 12ME June 30, 2023, to reflect a six-year average (2017-2022) of actual payouts. The use of a six-year average of payouts is consistent with Staff's methodology approved by the Commission in the litigated Dockets UE-170485 and UG-170486, and Dockets UE-200900 et. al.

For <u>non-executive employees,</u> the six-year average of incentive compensation

[32] Beginning January 1, 2023, the Company started recording restricted stock shares as a non-utility expense. The amounts represented above are related to expenses recorded during the 12ME 06.30.2023 test period that occurred between July 1, 2022 and December 31, 2022.

expense payout is $5.4 million (system) for O&M metrics designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. For executive officers, the six-year average expense payout of O&M metrics related to efficiencies in cost management (O&M cost-per-customer), customer service and reliability have averaged approximately $883,000 (system) in operating expenses. Incentive compensation related to financial metrics are excluded from the Company's filing with expenses borne by shareholders. The net effect of this adjustment, including both executive and non-executive changes, decreases Washington NOI by approximately $625,000 for electric and $198,000 for natural gas. See Adjustment 3.08 – Pro Forma Incentives for the Company's proposal to revise Company incentive compensation expense to expected RY1 levels.

Restate Debt Interest, column (2.14), restates electric and natural gas debt interest using the Company's pro forma weighted average cost of debt included in the pro forma studies of 2.57%, on the Results of Operations level of rate base shown in column (1.00) only. The weighted average cost of debt is as provided in the testimony and exhibits of Mr. Christie. This adjustment results in a revised level of tax-deductible interest expense on actual test period rate base. The Federal income tax effect of the restated level of interest for the test period decreases Washington net operating income by $226,000 for electric and $57,000 for natural gas.

The Federal income tax effect of the restated level of interest on all other rate base adjustments included in the Company's filing are included and shown as an income impact of each individual rate base adjustment described elsewhere in this testimony.

Restate Capital 06.2023 EOP, column (2.15), reflects net plant after ADFIT as of

June 30, 2023 on an AMA basis per results of operations, adjusted to reflect net plant after ADFIT at June 30, 2023 on an EOP basis per results of operations, consistent with the methodology approved in Dockets UE-200900 et. al. Ms. Benjamin sponsors and describes this adjustment within her testimony. The overall net effect of this adjustment on Washington rate base is $53,930,000 for electric and $12,408,000 for natural gas. This adjustment also increases Washington NOI by $291,000 for electric and by $67,000 for natural gas.

Eliminate WA Power Cost Deferral (Electric), column (2.16), removes the effects of the financial accounting for the Energy Recovery Mechanism (ERM). Under the ERM, certain differences in actual power supply costs, compared to those included in base retail rates, are deferred, and then surcharged or rebated to customers in a future period pursuant to the Commission-approved deferral and recovery mechanism. Revenue adjustments due to the ERM and the power cost deferrals affect actual results of operations and need to be eliminated to produce normalized results. The adjustment removes the ERM surcharge revenue as well as the deferral and amortization amounts and certain directly assigned power costs and net transmission costs associated with the ERM. The effect of this adjustment decreases NOI by $31,140,000.

Nez Perce Settlement Adjustment (Electric), adjustment column (2.17), reflects a decrease in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe in 1999 to settle certain issues regarding previously owned hydroelectric generating facilities of the Company. This adjustment directly assigns the Nez Perce Settlement expenses to the Washington and Idaho jurisdictions, which is necessary due to differing regulatory treatment in Idaho (Case No. WWP-E-98-11) and

Washington (Docket UE-991606). This restating adjustment is consistent with prior dockets since Docket UE-011595. The effect of this adjustment increases NOI by $12,000.

Normalize CS2 Major Maintenance (Electric), column (2.18), includes an adjustment to normalize major maintenance expense associated with Avista's Coyote Springs II (CS2) thermal project.[33] In Order 05, page 56, paragraph 153 of Docket UE-150204, the Commission ordered the Company, for regulatory purposes, to normalize and recover its major maintenance expense associated with this plant over a four-year period to match the major maintenance cycles of the plant.

In 2019 through 2021, CS2 major maintenance occurred totaling approximately $3.7 million system.[34] No CS2 major maintenance occurred in 2022 or 2023. For regulatory purposes consistent with UE-150204, the regulatory amortization expense level to include as of June 30, 2023 totals $519,000 on a system basis. To adjust from actuals ($0) to the current level of amortization ($519,000 system) as of June 30, 2023, Adjustment 2.16 reflects an increase in expense for Washington's share (64.40%) totaling $334,000. The net effect of this adjustment decreases NOI by approximately $264,000. See Adjustment 3.22 – Pro Forma Remove Normalize CS2 Major Maintenance and Ms. Andrews direct testimony, Exh. EMA-1T, for detailed discussion on the Company's proposed change in methodology for recovering its CS2 major maintenance expense by requesting a deferral and amortization

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[33] The previous restating adjustment Normalize Colstrip/CS2 Major Maintenance included Colstrip major maintenance expense, which is now excluded in base rates and recovered in electric Colstrip Tariff Schedule 99 per Dockets UE-220053, et., al.

[34] For CS2, major maintenance can vary, typically occurring every four years for a major overhaul, as is the case for the T3 Transformer ($2.2 million in 2019, trailing charges of $315,000 in 2020-2021). These amounts were amortized over 4-years. However, in the case of certain major maintenance on the steam turbine ($1.1 million from 2019-2021), this work is typically completed approximately every seven years. These amounts therefore were amortized over 7-years.

of CS2 major maintenance.

<u>Authorized Power Supply (Electric),</u> column (2.19). This adjustment restates the actual power supply costs for the test year 12ME 06.30.2023 to the level currently authorized in Dockets UE-220053, et. al. effective December 21, 2022. This adjustment results in an increase in Washington NOI of $46,582,000. See Adjustments 3.00P (Pro Forma Power Supply), 3.00T (Pro Forma Transmission Revenues) and 5.00P (Pro Forma Power Supply)[35] for the Company's proposed change in power supply net expense and base power supply costs over the Two-Year Rate Plan.

Q. Please provide an explanation for the final column on page 8, "Restated Total".

A. The last column on page 8, titled **Restated Total**, subtotals all the preceding columns (1.00) through column (2.19) electric and column (2.15) natural gas. These totals represent actual operating results and rate base, plus the standard normalizing adjustments that the Company includes in its annual Commission Basis reports (CBRs). However, the Restated Total column does not represent June 30, 2023 test period results of operation on a normalized commission basis as usually filed annually (on a calendar basis) with the WUTC on or before April 30. Differences exist related to the following: 1) inclusion of proposed (pro forma) cost of debt (pro forma versus CBR cost of debt) impacting Adjustment 2.14 above and 2) the inclusion of Adjustment 2.15 – Restate 06.2023 AMA Rate Base to EOP.

[35] Adjustment 5.00P (Pro Forma Power Supply), as discussed by Company witness Mr. Kalich, proposes to revise net power supply costs and the ERM baseline to reflect the mandated removal of Colstrip costs beginning January 1, 2026.

VII. RY1 & RY2 PRO FORMA & PROVISIONAL ADJUSTMENTS

A. RATE YEAR 1 – PRO FORMA STUDY

Q. Turning to pages 9 through 12 of Exh. KJS-2 and Exh. KJS-3, please explain the pro forma and provisional RY1 adjustments provided there.

A. Starting on page 9 of Exh. KJS-2 (electric) and Exh. KJS-3 (natural gas) are individual RY1 "Pro Forma" adjustments, (3.00) through (3.24) on page 12, for electric and (3.01) through (3.20), on page 12, for natural gas. These adjustments pro form costs beyond levels included in the Company's restated June 30, 2023 results and are reflective of costs incurred during the rate year. Individual RY1 "Provisional" adjustments for electric and natural gas begin in column (4.01) and continue through column (4.02) on page 12. These adjustments reflect "provisional" amounts reflective of costs incurred during RY1, impacting net plant and related expenses, that are subject to review and refund in a future period. Each of these adjustments are described below. RY2 pro forma and provisional adjustments are separately discussed later in this testimony.

1.) RY1 Pro Forma Adjustments

Q. Please begin with the first adjustment on page 9 of the electric Pro Forma Study, Exh. KJS-2.

A. The first RY1 Pro Forma adjustment on page 9 of the electric Pro Forma Study, Exh. KJS-2, is adjustment **Pro Forma Power Supply (Electric)**, column (3.00P). This adjustment was made under the direction of Mr. Kalich, as explained in detail in his testimony, outlining the system level of pro forma power supply revenues and expenses that are proposed in this adjustment. As discussed above, in Restating Adjustment (2.19) "Authorized Power Supply (Electric)," actual power supply costs for the test year 12ME

06.30.2023 are restated to the level currently authorized in Dockets UE-220053, et.al. This adjustment, therefore, adjusts the restated June 30, 2023 test period authorized level of power supply related revenue and expenses, to that proposed for the twelve-month RY1 rate period, using historical loads. This adjustment calculates the Washington jurisdictional share of those figures. The net effect, therefore, of adjustment (3.00P) Pro Forma Power Supply, decreases Washington NOI by $16,489,000.[36/37] See Pro Forma Power Supply Adjustment 5.00P below for the incremental increase in net power supply expense in RY2.

The adjustment in column (3.00T), **Pro Forma Transmission Revenue and Expense (Electric),** was made under the direction of Company witness Mr. Dillon and is explained in detail in his testimony. This adjustment includes pro forma transmission-related revenues and certain expenses to reflect the level of transmission revenues and certain expenses expected over the Two-Year Rate Plan.

Similar to Adjustment (3.00P) Power Forma Power Supply discussed above, Restating Adjustment (2.19) "Authorized Power Supply (electric)," also restates actual transmission revenues for the 12ME 06.30.2023 test year to the level currently authorized in Dockets UE-220053, et.al. This adjustment (3.00T), therefore, adjusts restated 06.30.2023 test period authorized transmission revenues effective with RY1, and continuing through the Two-Year Rate Plan. This adjustment calculates the Washington jurisdictional share of those figures. The net effect of Adjustment (3.00T) Pro Forma Power Transmission Revenue

[36] As discussed by Mr. Kalich at Exh. CGK-1T, the Company has included EIM system benefits of $5.5 million or $3.5 million Washington share. These benefits are reflected in PF Power Supply Adjustment 3.00P.

[37] After completion of the Company's electric revenue requirement in this case, a correction to pro forma Adj. 3.00P – Pro Forma Power Supply was found, increasing electric revenues by approximately $1.08 million and NOI by $851,000, and decreasing revenue requirement by approximately $1.1 million. The Company will update Adj. 3.00P during the process of the case.

and Expense, increases Washington NOI by $2,564,000.

Therefore, including the incremental net power supply costs of $21.9 million (revenue requirement) noted in Adjustment 3.00P, offset by incremental transmission revenues of $3.4 million (revenue requirement) per Adjustment 3.00T, results in a net increase in overall Washington electric revenue requirement in this proceeding for net power supply (and transmission revenues) of approximately $18.5 million above current authorized levels.

The next adjustment on page 9 of the electric Pro Forma Study Exh. KJS-2, and the first adjustment on page 9 of the natural gas Pro Forma Study, Exh. KJS-3, is adjustment **Pro Forma Revenue Normalization**, column (3.01), that adjusts electric and natural gas July 1, 2022 through June 30, 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 effective for the full 12-months of the test year. This adjustment also removes the impact of test period decoupling deferrals (GRC resets the base) and decoupling earnings sharing. For natural gas, this adjustment also eliminates Schedule 150 Gas Cost revenue and the associated cost of purchased gas. Mr. Garbarino is sponsoring electric adjustment (3.01), which has the effect of increasing NOI by $25,156,000. Mr. Anderson is sponsoring natural gas adjustment (3.01), which has the effect of increasing NOI by $1,922,000.

Pro Forma Def. Debits and Credits and Regulatory Amortizations, column (3.02), adjusts certain electric and natural gas items included in electric and natural gas restating adjustments (1.02), which are included on an AMA 12ME 06.2023 Commission

Basis level, to the level in effect for RY1. This adjustment revises expense associated with non-recurring or expiring regulatory amortizations or deferrals prior to the RY1 rate effective period, resulting in a net increase to amortization expense of approximately a $6.2 million for electric and a decrease to amortization expense of $244,000 for natural gas, mainly associated with the removal of the pension settlement deferral (regulatory credit) of $5.6 million for electric and $1.7 million for natural gas,[38] offset by the Washington Excess Natural Gas Line Extension amortization of $2.0 million for natural gas only. In addition, this adjustment includes the increased electric expense associated with the annual CPI adjustment for the Montana Riverbed Lease. The overall effect of this adjustment reduces electric NOI by $4,913,000 and increases natural gas NOI by $193,000.[39]

Pro Forma EDIT (Reverse South Georgia Method), column (3.03), adjusts the electric and natural gas excess deferred income taxes (EDIT) amortization expense included in the 12ME 06.30.2023 test period to reflect the level of EDIT amortization expense expected for the rate effective period. As discussed by Ms. Andrews, in 2017, the Tax Cuts and Jobs Act (TCJA) was enacted changing the corporate tax rate from 35% to 21%. As a result of the TCJA, the Company remeasured its deferred tax assets and liabilities to the new tax rate, resulting in the creation of EDIT on the 14% rate differential. The Company started to reverse the plant EDIT balance using the Average Rate Assumption Method (ARAM) through December 31, 2021. Beginning January 1, 2022, the Company switched its method

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[38] In addition, the Company eliminates the pension retirement regulatory deferral amount recorded to FERC Account 926 of $5.6 million for Washington electric and $1.7 million for Washington natural gas in Adjustment 3.07 – Pro Forma Employee Benefits, resulting in a net impact overall of $0.

[39] There are no further non-recurring or existing deferred debit/credit regulatory rate base and/or expense adjustments necessary beyond RY1. For new proposed regulatory amortizations, see Adjustment 3.18 – Pro Forma New Regulatory Amortizations.

of amortizing EDIT from ARAM to the Reverse South Georgia Method (RSGM). The Company's filed revenue requirement in this case utilizes the RSGM for both rate years. Ms. Andrews sponsors this adjustment and discusses the change from ARAM to RSGM in her testimony. The effect of this adjustment decreases electric NOI by $92,000 and natural gas NOI by $136,000. (See also Pro Forma EDIT Adjustment (5.09) (Electric), which further adjusts electric EDIT expense in RY2, to remove Colstrip EDIT expense as required by January 1, 2026.)

Pro Forma AMI Regulatory Amortization, column (3.04), restates 12ME 06.30.2023 test period balances, removing deferred expense balances, and recording the proper amounts for electric and natural gas AMI regulatory balances and amortizations during the RY1 effective period, as approved in Dockets UE-200900, et., al. For electric, the following adjustments are made: 1) regulatory AMI amortization expense is decreased by $0.3 million; 2) operating expenses are reduced $2.1 million, to reflect RY1 incremental O&M savings associated with the completed AMI project, and 3) rate base is reduced by $7.5 million, from test period levels. The net effect of these adjustments, therefore, increases electric NOI by $1,793,000.

Similarly, natural gas balances were adjusted as follows: 1) regulatory AMI amortization expense is decreased by $0.1 million; 2) operating expenses are reduced $0.7 million, to reflect RY1 incremental O&M savings associated with the completed AMI project, and 3) rate base is reduced by $2.1 million, from test period levels. The net effect of these adjustments, therefore, increases natural gas NOI by $623,000.

Pro Forma Adjustment (5.01) below, adjusts the electric and natural gas AMI Regulatory Asset balances and O&M expenses to expected RY2 levels, beyond RY1 levels.

Q. The next three adjustments (3.05) through (3.07) relate to pro forma labor and benefit adjustments, located on page 9 through page 10 of Exh. KJS-2 and page 9 Exh. KJS-3. Prior to addressing each of the adjustments, please provide an overview of the Company's total compensation philosophy.

A. Avista is committed to providing total compensation to employees that will attract and retain qualified people necessary to meet the needs and expectations of all utility interests, including but not limited to, customers, shareholders and regulators. To that end, the Company provides employees with cash compensation (base pay and variable pay in the form of pay-at-risk incentive compensation) and a comprehensive benefit package including medical and retirement. The overall package is designed to meet the following goals:

- Clearly identify the specific measures of Company performance that are likely to create long-term value for the Company's customers and shareholders;
- Keep employees focused on cost control, customer satisfaction, reliability and operational efficiencies by awarding variable pay for meeting pre-determined metrics;
- Promote a culture of safety;
- Pay competitively compared to others within our market;
- Reward outstanding performance; and
- Align elements of the incentive plans among all Company employees, including executive officers.

Each component is carefully considered within the overall package in order to provide total compensation which will be cost-effective for the Company, as well as attract and retain employees. Compensation components within the overall package may be adjusted over time to achieve the goal of recruiting and retaining qualified employees. The Company generally targets overall compensation levels within the range that is 15% above or below the median of Avista's peer group.

Q. Please now explain the pro forma labor and benefit adjustments starting

with adjustment (3.05) Pro-Forma Labor Non-Exec on page 9 of Exh. KJS-2 and KJS-3.

A. **Pro Forma Non-Exec Labor,** column (3.05), reflects changes in base pay, which together with pay-at-risk (see Short Term Incentive Compensation described below in Pro Forma Incentives Adjustment (3.08)) is designed to provide competitive compensation in the marketplace. The level of base pay is determined based on position qualifications such as level of education, professional designations or certifications, experience, roles and responsibilities, and within the market where we compete for talent.

Avista participates in numerous confidential salary surveys provided by third-party consulting firms, which compare Avista's pay programs and structure to other organizations in the utility industry, as well as other industries, regionally and nationally. Salary surveys are part of the input in the determination of salary increases and salary range updates (minimum, mid-point and maximum), as well as benchmarking jobs to market data. Avista benchmarks many jobs within the Company and reviews market data to determine if the salary range midpoints still accommodate the new estimated values established by the benchmarking process. The Company uses external peer group data provided by multiple surveys, and centralized in a tool named MarketPay[40] to benchmark against, and must react to external influences as they occur to remain competitive in the market and retain a qualified, high performing workforce. MarketPay enables our compensation team to quickly gather market information for similar positions in the areas we compete for talent. Based on

[40] "Payscale MarketPay is intended for global companies with large workforces, dedicated compensation teams, mature pay structures, and lots of survey data to manage. As our most advanced compensation platform, it streamlines survey management and enables native integration with Tableau." https://www.payscale.com/products/software/marketpay/

the information provided in these surveys, salary recommendations are presented to the independent Compensation Committee of the Board of Directors for their consideration and approval. The Compensation Committee can choose to grant higher or lower salary adjustments, based on the available market data.

The specific electric and natural gas adjustments included in Exh. KJS-2 and Exh. KJS-3, reflect changes to 12ME 06.30.2023 test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in adjustment (3.06). For non-union employees, the adjustment annualizes the impact of the actual increase effective March of 2023 and includes the expected March 2024 increase. The Company has included a preliminary salary increase for 2024. A final increase for non-union employees for 2024 will be approved by the Board of Directors early in the first quarter of 2024. The Company will update the adjustment should the actual approval be less than the minimum when approved at the Board meeting. In addition, the Company has applied an estimated prorated March 2025 increase through December 31, 2025, for total labor expense levels in RY1.[41]

Union employee increases are made in accordance with contract terms to annualize the impact of a 3.5% increase in 2023. The current contract with the IBEW Local 77 (Idaho/Washington) expires on March 25, 2025, with the merit increase open for negotiation beyond 2023. The Company is currently negotiating the 2024 merit and has included estimated merits for 2024 and 2025 in order to be consistent with non-union employees. The Company will update the agreed-on increase during the process of the case once it is

[41] See CONFIDENTIAL 3.05 & 5.02 Non-Executive Labor Adjustment workpaper, Pro-Forma Increases tab for annualized Union and Non-Union labor increases by year.

available. In total, this adjustment represents an increase in Washington expense in RY1, of $6.6 million electric and $1.8 million natural gas. The effect of this adjustment decreases Washington NOI by $5,210,000 for electric and $1,442,000 for natural gas. Pro Forma Adjustment (5.02) below includes the change in non-executive labor for RY2, above RY1 levels.

Turning to page 10 of Exh. KJS-2 and remaining on page 9 of Exh. KJS-3, **Pro Forma Labor-Executive**, column (3.06), reflects actual salary levels approved by the Board of Directors that are in effect as of June 2023, adjusted to the expected amount for 2024. This salary level is allocated between Utility and Non-Utility based on 12ME 06.30.2023 levels actual percentages[42] (90% utility /10% non-utility). This adjustment also reflects the changes (retirements and additions) in officers and their impact on salary expense from the test period to the rate-effective period. The impact of this adjustment increases Washington expense by $60,000 for electric and $19,000 for natural gas.

The Compensation Committee of the Board of Directors (Board) determined and approved the executive officer level of base salary effective March 2023, as with all components of executive officer compensation. The Board considers several internal factors such as individual and Company performance goals, succession planning, job complexity, experience, and breadth of knowledge in the determination of base pay. Similar to non-executive compensation, the Board also utilized external peer group data to benchmark its executives against a group of companies with similar business profiles, similar revenue size and market capitalization. These companies were reasonably assumed to be the companies

[42] For Executives who were new in 2023, the utility/non-utility percentages are estimated based on the previous Executives' actual allocation.

with which we compete for talent. The effect of this adjustment decreases Washington NOI by $47,000 for electric and $15,000 for natural gas.

Pro Forma Employee Benefits, column (3.07) electric and natural gas, adjusts the 12ME June 30, 2023 Retirement Plans (401(k) and Pension), and Medical Insurance for active employees and for those retired (post-retirement medical) to the expected amount for the RY1 rate-effective period. Annually, the Company works with independent consultants in order to determine the appropriate level of expense for both the Retirement Plans (Willis Towers Watson) and the Medical Plans (Mercer). The impact of these changes is summarized in Table No. 9 below: [43]

Table No. 9 – Pro Forma Benefit Adjustment RY1 – WA Electric and Natural Gas

Benefit Adjustment	RY1			
	System	System O&M	WA Electric	WA Natural Gas
Medical	$ (1,640,447)	$ (960,482)	$ (450,803)	$ (142,700)
Retirement	$ 1,278,855	$ 748,770	$ 351,436	$ 111,246
Pension Settlement Amortization	$ -	$ 492,816	$ 231,304	$ 73,218
Total	$ (361,592)	$ 281,104	$ 131,937	$ 41,764

The Company offers a comprehensive benefit plan for employees. Employees have several choices to elect benefits, such as medical and life insurance, so they can determine the best fit for their circumstances. The plans are designed to be competitive with the overall market practices and are in place to attract and retain qualified employees. Periodically, to aid in benchmarking, Avista participates in a comprehensive benefit evaluation study (BENEVAL) performed by an independent actuarial company, Willis Towers Watson. Similar to cash compensation, the Company generally targets the level of benefits it offers to

[43] Benefits associated with capital labor are embedded within the Company's capital adjustments.

be within +/- 15% of the market median.

Q. Please describe the Retirement portion of the Benefit Adjustment included in Adjustment 3.07 and Washington's share of this expense.

A. The Company's retirement portion of the calculation adjusts the 401(k) expense and Pension Plan from the 12ME 06.30.2023 test period to reflect what will be in effect during RY1, resulting in an overall increase in system expense of $749,000.[44]

Estimates for pension plan expense is determined annually by Willis Towers Watson based on the expected return on assets, discount rates and asset value. The primary contributor to changes in pension expense are related to changes in asset value due to the actual return on assets, changes in the discount rate and the expected long-term return on assets for the year prorated for the rate-effective period. Assumptions utilized in the calculation are presented to and approved by the Board of Directors annually.

In addition, these calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other Companies. The Company has included in this case the test year level of actual pension expense, therefore $0 pro forma at this time.[45] We anticipate updates for 2024 through 2026 to be available from our actuary sometime in the first quarter of 2024, after year-end results are available, and the Company will adjust pension expense at that time to reflect a prorated amount for RY1.

[44] See Pro Forma Employee Benefits Adjustment 5.03, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. The incremental overall system expense in RY2 for the Company's retirement portion is an increase of approximately $280,000.
[45] The test period actual expense was used as the basis for the rate effective period.

Further, the Company has made changes to the overall retirement plan, discussed below. The Company has proposed an increase consistent with proposed labor increases prorated for the rate effective period, as discussed in Pro Forma Labor Non-Exec Adjustment (3.05), resulting in an increase in 401(k) expense on a system basis of approximately $749,000 for RY1.[46] Over the long term, we anticipate a decrease in pension expense will reduce overall retirement net expense.

Q. Please summarize the changes to the Company's retirement plan in recent years.

A. In October 2013, the Company revised the defined benefit pension plan such that, as of January 1, 2014, the plan is closed to all non-union employees hired or rehired on or after January 1, 2014.[47] All actively employed non-union employees that were hired prior to January 1, 2014 and were covered under the defined benefit pension plan at that time, will continue accruing benefits as originally specified in the plan. In the 2022 Local 77 collective bargaining agreement, the Company and Local 77 bargaining unit have agreed to close the defined benefit pension plan to all Local 77 employees hired on or after January 1, 2024.[48] A defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union and Local 659 bargaining unit employees hired or rehired on or after January 1, 2014 and Local 77 bargaining unit employees hired on or after January 1, 2024. Under the defined

[46] See Pro Forma Employee Benefits Adjustment 5.03, which adjusts pro forma employee benefit amounts reflected in RY1, to reflect pro forma employee benefit amounts expected in RY2. The incremental increase in 401(k) expense on a system basis in RY2 is approximately $477,000.
[47] Changes were applicable to Local Union 659 (Oregon operations) effective April 1, 2014.
[48] Changes were applicable to the Local 77B (DO/GC) bargaining unit (Distribution Operations and Gas Controllers) with their contract placement in 2017.

contribution plan, the Company will provide a non-elective contribution as a percentage of each employee's base pay based on the age of the employee. This defined contribution is in addition to the existing 401(k) contribution where Avista matches a portion of the pay deferred by each participant. In addition to the above changes, the Company also revised our lump sum calculation for non-union retirees under the defined benefit pension plan to provide non-union participants who retire on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates. Beginning January 1, 2024, this will also apply to Local 77. Additionally, starting January 1, 2024 newly hired Local 77 bargaining unit employees will also receive a 5% enhanced Company contribution based on their base wage. Those who were covered under the defined benefit pension plan previously, will continue to accrue benefits as originally specified in the plan.

Q. Please describe the Pension Settlement Amortization portion of the Benefit Adjustment included in Adjustment 3.07 and Washington's share of this expense.

A. This portion of the adjustment reflects the amortization of the expected impacts associated with the occurrence of pension events related to the Non-contributory Defined Benefit Pension Plans (Pension Plan) deferred in December 2023 of approximately $11.8 million (system), with a 12-year amortization beginning January 1, 2023 as approved in Dockets UE-220898 and UG-220899, Commission Corrected Order 01. Test period results included 6 months of this amortization ($493,000 system), resulting in an incremental increase to expense of approximately $231,000 for Washington electric and $73,000 for Washington natural gas, to pro form the total annual level of expense anticipated in the rate effective period.

Q. Please now provide an overview of how medical expenses are determined by the Company.

A. Avista sponsors a self-funded medical plan that provides various levels of overage for medical, dental and vision as a portion of employee benefits. Annually, medical premiums[49] for the Company are estimated by an independent consultant, Mercer,[50] based on medical trend, which is a combination of utilization (the pattern of use or intensity of services used for a particular timeframe), and the estimated increase in the costs (such as medical services, office visits, medical equipment, etc.) to treat patients from one year to the next. The following factors are taken into consideration in the development of premiums:

- Population Profile – the number and composition of participating employees (such as single person, family, age, etc.).
- Estimated Medical and Prescription Costs – the increase in unit cost for a given medical service or treatments, the mix and intensity of differing types of service, and new treatments/therapy/technology.
- Laws and Regulation – changes and associated costs, such as those required as part of the Affordable Care Act.

Actual medical expense will vary from premium cost estimates based on variations in plan utilization and actual components in the medical trend. For the past several years, actual expense had been lower than our premium cost estimates, resulting in lower costs for the Company and our customers. Some reasons include the effects of the Company's wellness programs, the severity of flu season in a given year, the level of acute or chronic

[49] In this context, "premium" is defined as total medical costs including both the Company and employee contribution.
[50] Mercer is currently the world's largest human resources consulting firm, with more than 20,500 employees, based in more than 40 countries.

illness, or for a variety of other reasons. However, due primarily to increased utilization rates, price increases and our population profile, medical expenses have been trending upward.

As with the Pension Plan, estimates for the Post-Retirement Medical piece of the Medical adjustment are based on the expected return on assets, discount rates and asset value. In this case, the primary contributor to the increase in expense is related to an increase in cost trend assumptions. We anticipate updates for 2024 to be available sometime in the first quarter of 2024, and the Company will adjust expected medical expense, in this case, at that time. The net effect of the changes in medical costs on O&M expense described above, reflect a decrease in <u>system</u> O&M expense of $1.0 million.

As shown in Table No. 9 above, the overall net impact of changes in pension and medical expense on a system O&M expense basis is an increase of $281,000, or $132,000 Washington electric and $42,000 Washington natural gas. In addition, the Company also eliminated the pension retirement regulatory deferral amount recorded to FERC Account 926 of $5.6 million for Washington electric and $1.7 million for Washington natural gas.[51] Therefore, the Pro Forma Employee Benefits adjustment increases NOI for electric by $4,289,000 and for natural gas by $1,334,000. Again, the Company will update the level of expense as soon possible during the process of the case, after receiving updated consultant information expected in early 2024.

[51] In addition, the Company eliminates the deferred pension retirement regulatory liability (credit) amount recorded to FERC Account 407 of $5.6 million for Washington electric and $1.7 million for Washington natural gas in Adjustment 3.02 – Pro Forma Def. Debits and Credits and Regulatory Amortizations, resulting in a net impact overall of $0.

Pro Forma Adjustment (5.03) below, includes the change in employee Benefits expected for RY2, above RY1 levels.

Q. Continuing on page 10 of Exh. KJS-2 and turning to page 10 of Exh. KJS-3, please continue explaining the adjustments provided on this page.

A. The third adjustment on page 10 of Exh. KJS-2 and the first adjustment on page 10 of Exh. KJS-3 is **Pro Forma Incentives**, column (3.08). The Company, per normal practice, restated the level of test year incentives using the traditional six-year average of actual incentive expense (see Adj. 2.13). However, that level simply is not representative of the level of incentive expense the Company is forecasted to incur in RY1 (and carrying into RY2). As shown in Adj. 3.08, the Company is forecasting a level of non-executive and executive operating incentive that is $2.5 million (system) higher than what the restating adjustment provides. For Washington electric, that amounts to $1.2 million, and for natural gas $0.4 million. We simply cannot leave a combined $1.6 million of incentive expense that is reasonably likely to occur in the rate effective periods on the "cutting room floor", creating yet more regulatory lag. As stated elsewhere, incentive compensation is a critical component of our total compensation philosophy necessary to recruit – but now more than ever to retain – qualified employees to run our organization. As such, customers should have this benefit reflected in their retail rates. The effect of this adjustment reduces NOI by $919,000 for Washington electric and by $291,000 for Washington natural gas.

Q. Please provide an overview of the Company's non-executive employee short-term incentive plan ("Non-Executive Employee STIP").

A. In accordance with the Company's overall compensation design to align elements of incentive plans among all Company employees including executives, the Non-

Executive Employee STIP plan has essentially the same stated goals as the Short-Term Incentive Plan for executives (Executive STIP). Both plans provide incentives and focus employees on stated goals, while recognizing and rewarding employees for their contributions toward achieving those goals. The components of the Non-Executive Employee STIP are all operational in nature, including cost containment on a per-customer basis. The weighting of each component is as follows: 50% O&M Cost-Per-Customer, 20% Customer Satisfaction, 20% Reliability Index and 10% Response Time. This pay-at-risk component of compensation is part of the overall compensation for employees that is designed to be comparable with that of other similar utilities. If this pay-at-risk compensation were to be reduced or eliminated, then base pay would need to be increased in order for overall compensation to remain competitive.

Q. Please briefly describe the Executive STIP.

A. The Executive STIP is designed to align the interests of executives with both customer and shareholder interests in order to achieve overall positive operating and financial performance for the Company. The Executive STIP has four operational components, plus an earnings per share (EPS) components. The total amount associated with utility operational components is 40% and is broken down as follows: 20% O&M Cost-Per-Customer, 8% Customer Satisfaction, 8% Reliability, and 4% Response Time. The Consolidated Diluted EPS components accounts for 55% of the total opportunity and 5% Non-Regulated Activity. Only the operational components (40%) are proposed to be included in retail rates. Customers benefit from these metrics that are designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. The remaining 60% of the Executive STIP related to EPS and Non-Regulated Activity targets is borne by shareholders.

Q. What portion of the Short-Term Incentive Plans have been included in this case?

A. The Company has included 100% of the Non-Executive Employee STIP and 40% of the Executive STIP (excluding those metrics related to EPS and Non-Regulated Activity targets) in this case. All incentive compensation included in this case directly benefits customers either in cost containment and efficiencies, operationally via the reliability index and response time metrics, or customer satisfaction as measured via the Voice of the Customer Survey. By focusing employees on effective management of O&M costs, we are able to maintain or reduce charges to customers in future rate cases. The Company has excluded all incentive pay related to the EPS and Non-Regulated Activity portion of Executive STIP. In addition, a proportionate share of incentive pay for employees (in the same percentage as employee labor) related to non-utility operations has also been excluded from this case. Therefore, the appropriate portion of incentives related to Washington utility operations has been included in this case.

Q. Please describe the Long-Term Incentive Plan (LTIP).

A. The Long-Term Incentive Plan (LTIP) is comprised of two components, which serve two different purposes.[52] Performance Shares account for 75% of the plan with metrics related to Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). The purpose for this portion of the plan is to provide a direct link to the long-term

[52] As with all other components of the executive compensation, the Compensation Committee determines all material aspects of the long-term incentive – who receives the award, the amount of the award, the timing of the award, as well as any other aspects of the award that may be deemed material.

interests of shareholders by assuring that performance shares will be paid only if the company attains specified financial performance levels. This portion of the plan was modified in 2014 to include both Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). In previous years, vesting of performance-based equity awards were 100% contingent on the Company's Total Shareholder Return (TSR) relative to our peer group over a three-year period. Under the new design, two-thirds of the awards are contingent on TSR relative to our peers, and one-third is measured by our CEPS over a three-year period. The Company has <u>excluded</u> the costs associated with the Performance Share portion of the LTIP from the revenue requirement in this case.

Restricted Stock Unit (RSU) awards account for 25% of the LTIP and vesting is based on a continuation of service by the employee. The purpose for this portion of the plan is to provide an incentive for employees to remain with the Company. The long-term nature of large-scale utility projects spanning multiple years are completed more efficiently with experienced, consistent leadership. In addition, it is the Company's policy to promote from within when possible, preserving the values inherent in our culture that drive customer satisfaction, reliability of service, etc. Employees with a long tenure of employment with the Company are well versed in the Company's culture and tend to continue to cultivate the values embedded within Avista. The Company has excluded Washington's share of total Company LTIP test period expense in this filing – see Adj. 2.12 – Miscellaneous Restating Non-Utility/Non-Recurring Expenses.

Q. Please continue explaining the adjustments on page 10 of Exh. KJS-2 and Exh. KJS-3.

A. The next adjustment on page 10 of Exh. KJS-2 and Exh. KJS-3 is **<u>Pro Forma</u>**

<u>LIRAP Labor Expense</u>, column (3.09). This adjustment reflects the incremental labor expense of eleven additional employees beginning in 2022, totaling approximately $339,000 ($262,000 allocated to electric and $78,000 to natural gas) annually to account for the additional staffing support needed for its joint administration of the Low-Income Rate Assistance Program (LIRAP), as sponsored by Company witness Mr. Bonfield. This includes the creation of a specialized Bill Assistance Support and Evaluation (BASE) team, which is comprised of ten Customer Service Representatives (CSRs) and one Team Lead dedicated only to LIRAP administration – including not only direct customers services, but community outreach and engagement as well. As noted above, employees were hired beginning in 2022, therefore, this adjustment accounts for the incremental portion of these positions above test period levels. The effect of this adjustment decreases NOI by $207,000 for electric and $62,000 for natural gas.

<u>Pro Forma CCA Labor Expense</u>, column (3.10), reflects the incremental labor expense of four additional employees beginning in 2024, totaling approximately $494,000 ($381,000 allocated to electric and $113,000 to natural gas) annually, required to meet Climate Commitment Act (CCA) requirements. As discussed by Company witness Mr. Kinney at Exh. SJK-1T, new requirements outlined in the CCA have added significant processes to Avista's power and natural gas supply departments to account for activity associated with CCA compliance. Currently, this additional CCA work has been performed by existing employees. However, this resource approach cannot be sustained as other critical work has been either delayed or not adequately supported. The Company is hiring four additional positions in 2024 to support compliance with CCA. These positions include a <u>Climate Compliance Manager</u>, a <u>CCA Portfolio Manager</u>, an <u>Energy Supply Analyst</u>, and an

Investment Program Manager. The effect of this adjustment decreases NOI by $301,000 for electric and $89,000 for natural gas.

Pro Forma Property Tax, column (3.11), restates the 12ME 06.30.2023 level of property tax expense included in adjustment (2.02) Restate Property Tax, to expected RY1 property tax levels. The property on which the tax is calculated is the property value as of December 31, 2022, taxed at existing rates. The property tax balances include estimates for 2023-2026 and the Company will update with more current estimates through the process of the case. The effect of this adjustment increases NOI by $146,000 for electric and decreases NOI by $747,000 for natural gas. Pro Forma Adjustment (5.04) below, includes the change in Property Taxes expense expected for RY2, above RY1 levels.

Pro Forma Insurance Expense, column (3.12), as explained by Ms. Andrews, increases the 12ME 06.30.2023 test period level of insurance expense for general liability, directors and officers (D&O) liability, property and other (Cyber, Colstrip and Worker's Comp) insurance, to the level of insurance expense the Company is expecting during RY1 and over the Two-Year Rate Plan. The amount included for D&O insurance is reduced by 10% per Dockets UE-090134 and UG-090135. Final invoices for December 2023 for the Company's general and property insurance premiums, and estimated March 2024 for D&O and other insurance premiums were used to further estimate the planned insurance expense levels over the Two-Year Rate Plan. The Company will update any 2023/2024 estimated amounts, as well as updated insurance expense levels expected over the Two-Year Rate Plan included in this case as soon as any actual invoices in 2023/2024 are available.[53] The effect of this adjustment decreases NOI by $4,155,000 for electric and by $472,000 for natural gas.

Pro Forma IS/IT Expense, column (3.13), which adjusts the actual level of information services and technology (IS/IT) expense included in the 12ME 06.30.2023 test year to that expected over the Two-Year Rate Plan, effective with RY1. This adjustment includes the incremental costs primarily associated with contractual agreements in place, including amortization of pre-paid multi-year contracts, or are the continuation of costs for products and services that have increased beyond the 12ME 06.30.2023 historical test period associated with products and services, licensing and maintenance fees, and other costs for a range of information services programs known. These incremental expenditures are necessary to support Company cyber and general security, emergency operations readiness, electric and natural gas facilities and operations support, and customer service. Company witness Mr. Manuel supports and sponsors these increased costs, providing more information within his testimony. The effect of this adjustment decreases NOI by $80,000 for electric and by $16,000 for natural gas.[54]

The last adjustment on page 10 of Exh. KJS-2 and Exh. KJS-3, is electric and natural

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[53] See also Ms. Andrews Section IV. "Insurance Expense Balancing Account" in Exh. EMA-1T for additional information supporting the proposed continuation of the Company's current Insurance Expense Balancing Account, the pro forma level of expenses included in this case, as well as the proposed update to the Insurance Expense Balancing Account baseline to track expenses over the Two-Year Rate Plan, beginning with the RY1 effective date.

[54] As discussed by Mr. Manuel, the cost of the 3-year service agreement with ServiceNow (approximately $147,000 system per year cost) to bring their IT service management platform (ITSM) into the Company's portfolio, and savings associated with phase three of the Session Initiated Protocol (SIP) project (approximately $72,000 system per year savings) were not known/finalized until after the completion of the Company's proposed revenue requirement in this proceeding, and therefore were not included in Pro Forma IS/IT Expense Adjustment 3.13. During the process of the case, the Company will update its Pro Forma IS/IT Expense Adjustment. The net effect of this update increases IS/IT expenses approximately $75,000 (system) per year.

gas adjustment **<u>Pro Forma Miscellaneous O&M Expense,</u>** column (3.14). This adjustment, sponsored by Ms. Andrews, reflects escalated increases in certain Company O&M and A&G expenses, from the 12ME 06.30.2023 test year through RY1, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies. An annual escalation rate of 6.3% for electric and 4.57% for natural gas operations was applied by FERC account to certain O&M and A&G annual test period balances as of June 30, 2023, through December 2025 (or 2.5 years). All 12ME 06.30.2023 <u>test period expenses</u> restated or pro formed within the electric or natural gas Pro Forma Studies, are <u>excluded</u> prior to the use of the escalation, including the following expenses: 1) all labor and benefits, including, salaries, incentives, pension and medical costs; 2) insurance expenses and amortizations; 3) IS/IT expenses; 4) power supply costs; 5) Montana riverbed lease expenses; 6) Colstrip and CS2 major maintenance expenses; 7) wildfire related expenses; 8) administrative expenses (office space charges); and 9) other expenses removed through restating adjustments (i.e., miscellaneous restating, eliminate adder schedule balances, gas supply costs, and revenue-related expenses). This adjustment increases RY1 Washington expenses by $8,876,000 for electric and $1,634,000 for natural gas and decreases RY1 Washington NOI by $7,012,000 for electric and $1,291,000 for natural gas. Pro Forma Adjustment (5.06) below, and as sponsored by Ms. Andrews, includes the change in Miscellaneous O&M/A&G expense expected for RY2, above RY1 levels.

Q. Please turn to page 11 of Exh. KJS-2 and Exh. KJS-3 and continue discussions with the next pro forma adjustment.

A. The next adjustment, first shown on page 11 of Exh. KJS-2 and Exh. KJS-3, is **<u>Pro Forma Capital Additions to 12.31.2023 EOP</u>,** column (3.15), which restates

06.30.2023 EOP historic test year balances to EOP balances as of December 31, 2023. As discussed, and sponsored by Ms. Benjamin, this adjustment was comprised of three components. The first component adjusts EOP June 30, 2023 rate base to EOP December 31, 2023 rate base by extending A/D and ADFIT balances on utility plant-in-service from June 30, 2023 EOP balances to December 31, 2023 EOP balances. The second component reflects the impact of retirements from July 1, 2023, through December 31, 2023. The third component reflects additions to plant-in-service, inclusive of new growth capital[55], between July 1, 2023, and December 31, 2023, on an EOP basis, inclusive of the depreciation expense, A/D, and ADFIT associated with these additions for the period. This adjustment also adjusts depreciation expense to reflect the appropriate level of expense at December 31, 2023. In January 2024, the Company will record final actual additions through year-end December 31, 2023, and consistent with prior practice, will provide updated actual transfers-to-plant to all Parties, and an updated Adjustment (3.15) as soon as available. The impact of this adjustment increases net rate base by $83,421,000 for electric and $19,488,000 for natural gas, and decreases NOI by $2,861,000 for electric and $898,000 for natural gas.[56]

Pro Forma Depreciation Expense, column (3.16), for electric and natural gas, captures the effect of updating electric and natural gas depreciation rates for both common/allocated plant and direct Washington plant effective January 1, 2024, on plant-in-

[55] For the period July 1, 2023 through December 31, 2025, capital additions associated with connecting new customers to the Company's system (New Revenue – Growth Business Case) were included. As discussed by Ms. Andrews in her testimony, an increase in revenues from growth in the number of customers from the historical test year to the RY1 and RY2 rate periods are included, therefore, the growth in plant investment associated with customer growth was also included.

[56] Offsetting factors on pro forma capital additions for the period July 2023 through December 2023 are reflected in PF Adjustment 3.15 through inclusion of retirements and reductions to rate base for reducing existing net plant for A/D and ADFIT. Other offsets related to 2023 additions included in the test period 12ME 06.2023 (January – June 2023) would already be reflected in the test period.

service at December 31, 2023, on an AMA basis. In accordance with Order 01 in Dockets UE-230123 and UG-230130 dated December 21, 2023, the Commission approved the Company's application to set new electric and natural gas depreciation rates effective January 1, 2024 per the Company's revised filed depreciation study. The impact of changing depreciation rates for plant-in-service at January 1, 2024, on an EOP basis and all additions after January 1, 2024, are built into the other capital adjustments (3.17, 4.01, 5.07). The impact of this adjustment increases NOI by $593,000 for electric and $714,000 for natural gas.

The next adjustment is **Pro Forma Capital Additions to 12.31.2024,** column (3.17), for electric and natural gas. This adjustment, as sponsored by Ms. Benjamin, is composed of three parts. The first component adjusts plant-in-service at December 31, 2023 EOP balances to December 31, 2024 EOP balances by extending A/D and ADFIT balances. The second component reflects the impact of retirements from January 1, 2024 through December 31, 2024. The third component reflects additions to plant-in-service, inclusive of new growth capital, between January 1, 2024 and December 31, 2024, on an EOP basis, inclusive of the depreciation expense, A/D, and ADFIT associated with these additions for the period. This adjustment also adjusts depreciation expense to reflect the appropriate level of expense at December 31, 2024.

The net impact of this adjustment on electric increases net rate base by $70,224,000 and decreases NOI by $3,292,000. For natural gas, this adjustment increases net rate base by $20,568,000 and decreases NOI by $1,435,000. Detailed information supporting these capital additions are included in testimony and exhibits of witnesses Mr. Alexander, Mr. DiLuciano, Mr. Manuel, Mr. Howell, and Ms. Hydzik. Details supporting this adjustment is available in Exh. TCB-2 (native version) provided with this filing, as well as in Ms. Benjamin's workpapers provided to all Parties after filing of this case.

Q. The next column on page 11 of Exh. KJS-2 and Exh. KJS-3 is related to <u>Pro Forma New Regulatory Amortizations</u>, column (3.18). Please individually describe the amortizations included in Adjustment 3.18, beginning with the <u>electric</u> amortization related to <u>Wildfire Resiliency</u>.

A. On October 30, 2020, Avista filed with the Commission in Docket UE-200894 a petition for an accounting order authorizing the accounting and ratemaking treatment of the costs associated with the Company's Wildfire Resiliency Plan. That Docket was consolidated with Avista's 2020 general rate case, Dockets UE-200900 et. al. In Final Order 08/05, the Commission stated at ¶243: "We find it appropriate, however, to approve Avista's request that it be allowed to defer the incremental wildfire expenses incurred from January 1, 2021, through September 30, 2021." This adjustment captures the Washington <u>electric</u> deferred costs as of June 30, 2023 (for the period January 1, 2020 through September 30, 2021), totaling approximately $1.84 million, recorded in FERC Account 182344 – Regulatory Asset – Wildfire Resiliency WA Deferral, to be included in base rates and amortized for <u>recovery</u> over two years beginning December 21, 2024.

Q. Please describe the <u>electric</u> amortization related to the <u>Turner Battery Storage Deferral</u> included in Adjustment 3.18.

A. On December 15, 2021, Avista filed for deferred accounting treatment in Docket UE-210949 related to the failure of the Turner Energy Storage (TES) battery located in Pullman, Washington. As detailed in the Company's request, which was approved by the Commission in Order 01 dated January 13, 2023, in the Spring of 2015, Avista installed and commissioned the TES project in Pullman, Washington at the Schweitzer Engineering Laboratories (SEL) site.[57] The project was funded in part through a Clean Energy Fund grant from the Washington State Department of Commerce (Commerce) in the amount of $3.2 million. For this project, Avista selected a vanadium flow battery supplied by UET and associated inverter with 1MW of power and energy capability of 3.2MWh. The construction of the battery, inverter set (#1) and transformer set (#1) was completed and moved into production in April 2015. In February 2018, an additional invertor (#2) and transformer (#2) was added, and in April 2018, the testing had been completed and the system was functioning. Although these additional assets were useful, they were not yet being used and remained in Construction Work in Progress (CWIP).

In June 2018, the battery failed. Between the time of the failure and June 2021, Avista and UET worked to obtain a warranty replacement of the system. However, in May 2021, Avista learned that UET was experiencing financial difficulties. In July 2021, Avista sent a letter to UET demanding that it either (a) provide a date that a replacement battery would be delivered and post a performance bond; or (b) refund to Avista all amounts paid to UET. In November 2021, UET's counsel informed Avista that involuntary bankruptcy proceedings had been instituted against UET. Since that time, UET has been unable to provide any financial remediation to the Company, and is unlikely to do so in the future.

Q. Do you believe that the project, while unsuccessful, was prudent in terms of scope and cost?

A. Absolutely. As noted above, this project was funded with a Department of

[57] In addition to Avista, a Washington-based project consortium was engaged in this project, including the Pacific Northwest National Laboratory (PNNL), Washington State University (WSU), and UniEnergy Technologies (UET).

Commerce Clean Energy Fund grant. The TES project was designed to demonstrate the dual use of energy storage to perform reliability operations as well as perform grid services. Test projects by their very nature are imperfect; failures can occur as happened in this instance. That does not demonstrate imprudence, in fact one might argue that not taking reasonable steps to test new technologies, especially in the environment today around proliferating clean energy, would be imprudent. For this project, Avista partnered with multiple entities including WSU, PNNL and the Department of Commerce to both test a new technology as well as to leverage funding opportunities (which is not dissimilar from the work Avista is doing related with federal grants like the IIJA and IRA as discussed by Company witness Ms. Scarlett).

Q. What is the total deferred balance related to TES, and how is the Company proposing to amortize that amount?

A. This adjustment proposes the Washington <u>electric</u> deferred costs as of December 31, 2024, totaling approximately $3.4 million, recorded in FERC Account 186070 – Regulatory Asset – Battery Storage (Turner Battery Storage Deferral (2022)), be included in base rates and amortized for <u>recovery</u> over two years beginning December 21, 2024.

Q. Would you please describe the <u>electric and natural gas</u> amortization related to <u>COVID 19 Deferral (Net)</u> included in Adjustment 3.18?

A. Yes. In Dockets UE-200407 and UG-200408, in Order 01, the Commission approved Avista's revised petition allowing for it to defer the costs, revenues, and benefits identified in the Company's filing. Those items included bad debt expense, COVID-19 Grants from the American Rescue Plan, costs associated with Avista's COVID Assistance

Program described in the "UTC Staff Proposed COVID-19 Response Term Sheet" in Docket U-200281 on February 19, 2021, short-term loan interest and fees, CARES Act tax benefits, and other items. The Company filed with the Commission quarterly reports detailing all of the costs and benefits throughout the deferral timeframe. Table No. 10 below provides the summary of the deferral as of September 30, 2023 (which was provided to the Commission on October 27, 2023 in the above referenced dockets).

Table No. 10 – WA COVID Deferral Summary

Washington COVID Deferral Summary as of 9/30/2023			
Deferral Type	**WA E**	**WA G**	**Total**
Bad Debt Expense	$ 1,508,276	$ 766,974	$ 2,275,250
COVID Assistance Program	5,495,044	1,213,633	6,708,677
Term Loan Interest/Fees	286,789	69,766	356,555
Other Direct COVID Costs	248,433	77,955	326,388
Reconnect Fees	97,401	4,552	101,953
Total 186	7,635,943	2,132,880	9,768,823
Other Direct COVID Benefits	(2,257,340)	(709,979)	(2,967,319)
CARES Act Tax Benefit	(3,269,013)	(1,512,768)	(4,781,781)
Total 253	(5,526,353)	(2,222,747)	(7,749,100)
Total Ending Balance at 9.30.2023	**$ 2,109,590**	**$ (89,867)**	**$ 2,019,723**

This adjustment proposes the Washington electric deferred costs as of December 31, 2024, totaling approximately $2.1 million, and natural gas deferred benefits of $0.1 million, recorded in FERC Accounts 186347 – Regulatory Asset COVID-19, 186349 – Regulatory Asset – COVID-19 Forgiveness Program, and 253347 – Regulatory Liability – COVID-19 Deferral (COVID 19 Deferral (Net) (2020-2023)), be included in base rates and amortized for recovery (electric) or rebate (natural gas) over two years beginning December 21, 2024.

Q. Please describe the electric amortization related to the Montana Riverbed Escrow Interest Deferral included in Adjustment 3.18.

A. On June 30, 2023, Avista filed with the Commission in Docket UE-230548, a request for an order approving deferred accounting associated with the Montana Riverbed Lease Agreement. As discussed in that filing, on May 4, 2023, Avista received notice of the release of funds for the Montana Riverbed lease payments for the rent years 2016-2020 from the escrow account in which they have been held. Additionally, the notice identified the additional amount owed by Avista that represents the interest component, calculated to be $3,766,353 (system basis) as of February 28, 2023, which was the difference between the calculated ending escrow balance including interest of $28,288,773 and the actual amount held in the escrow account of $24,522,420. Presently, the Company is recovering from customers the ongoing lease expense, but the calculation of the interest component was not known until the receipt of the letter. Approval of deferred accounting for these costs was necessary, so the Company has the opportunity to recover these costs from customers in the future.

Avista was able to negotiate with the State of Montana and agree upon a final interest calculation of $1.6 million, on a system basis. Washington's share of this is $1.14 million. This adjustment proposes the Washington electric deferred costs as of June 30, 2023, totaling approximately $1.14 million, recorded in FERC Account 182377 – Regulatory Asset – Montana Riverbed Escrow Interest Deferral (2023), be included in base rates and amortized for recovery over two years beginning December 21, 2024.

Q. Would you please describe the electric and natural gas amortization related to WA Regulatory Fee Deferral (2023 & 2024) included in Adjustment 3.18?

A. Yes. On December 2, 2022, Avista filed with the Commission a petition, Dockets UE-220892 and UG-220893, seeking an accounting order authorizing the Company to utilize deferred accounting treatment for the Company's increased costs associated with the updated Commission regulatory fees approved in Senate Bill 5634 (SB 5634) in 2022. This law raised the Commission's regulatory fee from 0.2 percent to 0.4 percent of "gross operating revenue from intrastate operations for the preceding calendar year." These amounts became payable to the Commission in May 2023. The Commission approved the Company's request on January 26, 2023 in Order 01.

This adjustment proposes the Washington electric and natural gas deferred costs as of December 31, 2024 (for the period January 1, 2023 through December 31, 2024), totaling approximately $2.9 million electric, and $1.5 million natural gas, recorded in FERC Account 182343 – Regulatory Asset – Deferred Regulatory Fees (WA Regulatory Fee Deferral (2023 and 2024)), be included in base rates and amortized for recovery over two years beginning December 21, 2024.

Q. Please describe the electric amortization related to the EIM Provisional Capital Rate Refund (2022) included in Adjustment 3.18.

A. In Dockets UE-200900 et. al., the Commission approved in Order 08/05 a level of capital investment related to Avista's joining of the CAISO Western Energy Imbalance Market (EIM). As discussed by Mr. Kinney at Exh. SJK-13T in Docket UE-200900, Avista needed to complete all of its EIM equipment upgrades/replacements and integrate all new software by July 1, 2021 per the CAISO implementation schedule. However, although the equipment-related projects were completed by July 1, 2021, the software applications (while complete) would not officially transfer-to-plant until all testing is complete and the Company officially joins the EIM in March 2022. Therefore, the Company committed to provide actual transfers-to-plant, as well as transactional CWIP balances, as required, through these quarterly reports, until EIM go-live, and all investments have transferred to plant-in-service.[58]

The net overall EIM rate base authorized in UE-200900 for Washington electric results, on an AMA basis for the rate effective period (twelve-months ending 09.2022), totaled $12,577,000. However, the actual EIM rate base for Washington electric results, on an AMA basis for the rate effective period, totaled $11,227,000, a net rate base difference of $1,350,000. The overall impact associated with this understatement of net rate base, related depreciation expense, debt interest and return on investment, resulted in an annual revenue requirement owed customers of $284,000. Given new rates were effective on October 1, 2021 in the referenced case, and new rates from the Company's next general rate case were effective on December 21, 2022 (Dockets UE-220053 et. al.) including this change in rate base, the Company deferred $347,000 for amounts owed customers for the period October 1, 2021 through December 20, 2022, plus accrued interest at the Company's authorized rate of return.

This adjustment proposes the Washington electric deferred benefit as of December 31, 2024 (for the period 2022), totaling approximately $0.5 million electric, recorded in FERC Account 229030 – EIM Provisional Capital Rate Refund (2022), be included in base rates and amortized for rebate over two years beginning December 21, 2024.

Q. Would you please describe the electric amortization related to the CS2 Insurance Proceeds Deferral (2022) included in Adjustment 3.18?

[58] Per Order 08/05, the Commission's authorized electric base rate revenue requirement, effective October 1, 2021, included the Company's EIM pro forma/provisional capital adjustment 3.18. These adjustments included capital additions starting in 2020 through go-live of March 2022, plus trailing invoices capitalized in 2022. Including this report, additional quarterly reports were filed by Avista in January 2022 and April 2022 to incorporate all trailing (final) invoices in 2022, to report on quarterly transfer-to-plant results for the EIM project through completion.

A. In Docket UE-210893, on November 17, 2021, Avista filed with the Commission a petition seeking an accounting order authorizing the Company to defer any insurance claim proceeds received related to the failures of equipment at the Coyote Springs 2 (CS2) natural gas generating facility. The filing complied with paragraph 204 of the Commission Order 08/05 in Docket UE-200900 et. al., which required Avista to file with the Commission (1) an accounting petition to defer the insurance clam proceeds associated with the CS2 Single Phase, and (2) an accounting petition to defer any insurance claim proceeds associated with any material future distribution infrastructure failure, such as a failed transformer, for which the Company submits an insurance claim. The Company received $2.5 million of insurance proceeds in total, $1.3 million was offset against capital additions, with the remaining $1.2 million deferred to return to customers, in both WA and ID.

This adjustment proposes the Washington <u>electric</u> deferred <u>benefit</u> as of December 31, 2024 (for the period January 1, 2023 through December 31, 2024, including interest), totaling approximately $1.0 million electric, recorded in FERC Account 254302– CS2 Insurance Proceeds Deferral (2022), be included in base rates and amortized for <u>rebate</u> over two years beginning December 21, 2024.

Q. Please describe the <u>electric and natural gas</u> amortization related to <u>WA Deferred Depreciation Expense (2024)</u> included in Adjustment 3.18.

A. Yes. In Dockets UE-230123 and UG-230130, the Commission in Order 01 approved Avista's Amended Accounting Petitions to revise depreciation rates and authorize deferred accounting treatment for the difference in the resulting depreciation expense. This deferral, effective January 1, 2024, reflects the benefits for customers from the revised deprecation rates until they are included in base rates at the conclusion of this general rate case. This adjustment proposes the Washington electric and natural gas deferred benefits as of December 31, 2024 totaling approximately $0.7 million electric, and $0.8 million natural gas, recorded in FERC Account 254227 – Depreciation Regulatory Liability (WA Deferred Depreciation Expense (2024)), be included in base rates and amortized for rebate over two years beginning December 21, 2024.[59]

The net overall impact of this adjustment (3.18) increases expense $4.6 million electric, and $300,000 for natural gas, and decreases NOI by $3,616,000 for electric and $237,000 for natural gas.

Q. Please continue with the adjustments on page 11 of Exh. KJS-2 and Exh. KJS-3.

A. The next adjustment on page 11 of Exh. KJS-2 and final adjustment on page 11 of Exh. KJS-3 is **Pro Forma Nucleus/ETRM Expense,** column (3.19). This adjustment reflects the incremental expense related to the implementation of the Company's new Energy Trade and Risk Management (ETRM) system. As sponsored and discussed by Mr. Kinney, Exh. SJK-1T, the Company plans to implement a modern ETRM with the necessary associated software to gain efficiencies, reduce spreadsheet reliance, increase frequency and visibility of position reporting, while leveraging an industry-wide vendor who will maintain compliance and support with organized market changes and state policies. An incremental $1.2 million system ($563,000 Washington electric and $178,000 Washington natural gas) in expense is needed in 2025 to conduct a software RFP process, hire a system integrator, and support incremental labor associated with RFP requirements and vendor evaluation. The

[59] As discussed by Ms. Benjamin, the Company has included within this case the effect of updating electric and natural gas depreciation rates for both common/allocated plant and direct Washington plant to those approved per Order 01 in Dockets UE-230123 and UG-230130 dated December 21, 2023, effective January 1, 2024.

effect of this adjustment decreases NOI by $445,000 for electric and by $141,000 for natural gas. See Adjustment 5.05 – Pro Forma Nucleus/ETRM Expense for a reduction in ETRM expense levels for RY2, from the anticipated RY1 level.

Remaining on page 11 of Exh. KJS-2 and turning to page 12 of Exh. KJS-3, the last pro forma RY1 adjustment for natural gas, **Pro Forma Board of Director (BOD) Fees Expense,** column (3.20), increases director fee expense to reflect a 90% utility / 10% non-utility split. This adjustment, as proposed by Avista, revises the effect of adjustment 2.12 (director fee expense noted above) reflecting a 50%/50% sharing, to reflect the proper level of director fee expense that should be included during the rate period. The effect of this adjustment decreases Washington NOI by $374,000 for electric and by $119,000 for natural gas.

Q. As noted above, the Company is proposing to exclude 10% of Director Fee expenses, rather than 50%. What is the basis for removing only 10% of these costs?

A. Adjustment 2.12 (Miscellaneous Restating Non-Utility/Non-Recurring Expenses Adjustment) reduces the test period director fee allocated expense to a 50/50 sharing. The Company believes director fees are now understated, and that the 90/10 split is a better indication of the proper costs to charge that should be included in retail rates. In Dockets UE-090134 and UG-090135, Order 10, in reference to a 90/10 sharing for D&O insurance, the Commission stated:

> D&O insurance is a benefit that is part of the compensation package offered to attract and retain qualified officers and directors. Accordingly, it makes sense to split the costs in the same manner we require other elements of their compensation to be shared. Based on the formula currently used to allocate officer compensation between ratepayers and shareholders, this results in 90 percent of the costs being

included for recovery in rates. (emphasis added) (See page 56, paragraph 137)

This Commission, as shown above, has recognized that D&O insurance is part of the "compensation package" (splitting such costs on a 90/10 basis). Similarly, Directors' fees, like D&O insurance referred to above, are a part of the Directors' compensation package offered to attract and retain qualified Directors. It is also important to recognize the changing makeup of Avista in the last ten years. Back in the 2000's and up to 2014, Avista had a portfolio of companies, including the utility, but also subsidiaries including Avista Energy, Avista Labs, and Ecova. Avista has divested itself of those entities, and today is comprised almost entirely of utility operations, with just a small set of passive investments under Avista Capital. As such, the BOD is focused primarily on our utility operations, and it is important to recognize that in rates. Based on the actual time dedicated to the utility by its Board of Director's, a 90%/10% sharing of these fees is conservative.

<u>Pro Forma Transportation Electrification Return (Kicker) (Electric)</u>, column (3.21), includes the incentive rate of return (return "kicker") for RY1 on the Transportation Electrification capital investments included in this case. As discussed by Ms. Hydzik, pursuant to RCW 80.283.360, the Company is seeking an incentive rate of return of 2% as allowed per statute, which totals approximately $99,000 in RY1, and an incremental $27,000 in RY2. Grossed up for taxes, the amount included in Exh. KJS-2, page 11, column (3.21) totals $132,000 for RY1. The impact on electric NOI for this adjustment is a decrease of $104,000. The incremental Transportation Electrification Return for RY2, above RY1 levels is included in Pro Forma Adjustment (5.10) below.

Q. Continuing on page 12 of electric Exh. KJS-2, please discuss the final

three electric RY1 pro forma adjustments.

A. The final three (electric only) RY1 pro forma adjustments begin with **Pro Forma Remove Normalize CS2 Major Maintenance (Electric)**, column (3.22). As discussed by Ms. Andrews, this adjustment removes the normalized CS2 major maintenance expense recorded in Adjustment 2.18 (Restating Normalize CS2 Major Maintenance Adjustment). Because the Company does not believe it is appropriate to record CS2 major maintenance using a 4-year average for book purposes only (see Ms. Andrew's Section VI. "2026 CS2 Deferral of Major Maintenance and Recovery"), the Company proposes to adjust RY1 major maintenance expense to $0, reflecting actual test period, as well as RY1 expense levels. The effect of this adjustment reduces major maintenance expense by $334,000 and increases NOI by approximately $264,000. Resulting in a net $0 major maintenance expense in RY1 related to CS2.

Pro Forma Power Purchase Agreement (PPA) Interest (Electric), column (3.23), reflects the recovery of interest in RY1 on Washington's share of certain 2024 – 2025 Power Purchase Agreements (PPAs). As discussed by Mr. Kinney, pursuant to RCW 80.28.410(2)(b), the Company has included interest on qualifying PPAs (Chelan, Clearwater III and Columbia Basin Hydro) at the Company's proposed rate of return in this general rate case of 7.61%. The result of the Company's pro forma adjustment includes interest totaling $2.16 million included for RY1 (2025), reflecting interest to be deferred in 2024 of $0.66 million and recovered in 2025, and incremental interest in 2025 of $1.50 million. The net impact of this adjustment decreases Washington electric NOI by $1,706,000. Pro Forma Adjustment (5.12) below, includes the incremental increase in PPA interest expense expected for RY2, above RY1 levels.

Q. Please discuss the final electric <u>pro forma</u> adjustment on page 12 of Exh. KJS-2.

A. The final pro forma adjustment on page 12 of Exh. KJS-2 is **<u>Pro Forma Wildfire Plan Expenses (Electric),</u>** (column 3.24). As discussed by Ms. Andrews, this adjustment reflects the net increase in expenses associated with the Company's Wildfire Resiliency Plan ("Wildfire Plan"), as supported by Company witness Mr. Howell.[60]

Specifically, this pro forma adjustment reduces 12ME 06.30.2023 test period distribution and transmission operating expenses by $2,369,000 to reflect Washington's share of annual wildfire operating expenses expected during the Two-Year Rate Plan of $8,323,000. This adjustment also removes non-recurring test period deferred regulatory credit expense from the test period (removes FERC Account 407 balances), related to deferring wildfire expenses during the period July 1, 2022 through June 30, 2023, increasing administrative and general (A&G) Regulatory Amortization expense by $6,425,000. The net of this adjustment increases related wildfire expense by $4,056,000 above test period levels, prior to the impact of depreciation expense related to pro formed Wildfire Plan capital additions.[61] The effect of this adjustment decreases Washington electric NOI by $3,204,000. See Ms. Andrews Section III. "Wildfire Expense Balancing Account" in Exh. EMA-1T, which provides additional information supporting the pro forma expenses and capital

[60] Wildfire Plan capital additions, together with associated A/D, ADFIT, and depreciation expense, from July 1, 2023 through December 31, 2026 over the Two-Year Rate Plan are included in Pro Forma Capital Additions Adjustments 3.15 (12.2023 EOP) and 3.17 (12.2024 EOP), and Provisional Capital Additions Adjustment 4.01 (2025 AMA) in RY1, as well as Provisional Adjustment 5.07 (2026 AMA) in RY2, sponsored by Ms. Benjamin. Mr. Howell discusses the need for these additions in his direct testimony.

[61] *Ibid.*

investment included in this case, as well as the proposal to update the Wildfire Expense Balancing Account baseline to track expenses over the Two-Year Rate Plan, beginning with the RY1 effective date.

2.) RY1 Provisional Adjustments

Q. Moving now to "provisional" adjustments in RY1, would you please discuss the two "provisional" adjustments (4.01-4.02) on page 12 of Exh. KJS-2 and Exh. KJS-3?

A. Yes. Continuing on page 12 of Exh. KJS-2 and Exh. KJS-3 is the first RY1 "provisional" adjustment, **Provisional Capital Additions to 12.31.2025 AMA**, column (4.01), for electric and natural gas. This adjustment, sponsored by Ms. Benjamin, is composed of three parts. The first component adjusts plant-in-service at December 31, 2024 EOP balances to December 31, 2025 AMA balances by extending A/D and ADFIT balances. The second component reflects the impact of retirements from December 31, 2024 EOP balances to December 31, 2025 AMA balances. The third component reflects additions to plant-in-service, inclusive of new growth capital, between December 31, 2024, on an EOP basis and December 31, 2025, on an AMA basis, inclusive of the depreciation expense, A/D, and ADFIT associated with these additions for the period. This adjustment also adjusts depreciation expense to reflect the appropriate level of expense at December 31, 2025.

The net impact of this adjustment on electric increases net rate base by $25,761,000 and decreases NOI by $4,015,000. For natural gas, this adjustment increases net rate base by $3,204,000 and decreases NOI by $1,697,000. Detailed information supporting these capital additions are included in testimony and exhibits of witnesses Mr. Alexander, Mr.

DiLuciano, Mr. Manuel, Mr. Howell, and Ms. Hydzik. Details supporting this adjustment is available in Exh. TCB-2 (native version) provided with this filing, as well as in Ms. Benjamin's workpapers provided to all Parties after filing of this case.

The second, and final, "provisional" adjustment for RY1 electric and natural gas is adjustment **2024-2025 Capital Additions O&M & Revenue Offsets,** column (4.02). This adjustment, as sponsored by Ms. Andrews and further described in Section V. "Pro Forma Offsetting Factors – Direct & Indirect" of Exh. EMA-1T, includes RY1 reductions for: 1) direct O&M savings for certain capital Business Cases, 2) an incremental "2% O&M efficiency" adjustment, reducing O&M expense, for all remaining capital Business Cases (not required for regulatory purposes), and 3) offsetting revenue associated with the New Revenue – Growth Capital Business Case. These direct O&M offsets, "2% efficiency" O&M offsets, and revenues are shown in detail in Ms. Andrews' Exh. EMA-3. The net impact of this adjustment for electric increases revenue by $6,382,000, reduces expenses $917,000, and increases NOI by $5,766,000. For natural gas, the net impact of this adjustment increases revenue by $344,000, reduces expenses $279,000, and increases NOI by $492,000.

Q. Completing the electric and natural gas Pro Forma Studies for RY1, please discuss the final column on page 12 of Exh. KJS-2 and Exh. KJS-3.

A. For electric, the final column on page 12 of Exh. KJS-2, is the final RY1 total column labeled "RY1 12.2024 FINAL TOTAL," showing the RY1 total pro forma operating results (NOI of $117,786,000) and rate base ($2,309,817,000) for the RY1 pro forma test period, and the total electric revenue requirement need of $77,067,000.

For natural gas, the final column on page 12 of Exh. KJS-3, is the final RY1 total column labeled "RY1 12.2024 FINAL TOTAL," showing the RY1 total pro forma operating results (NOI of $31,586,000) and rate base ($586,084,000) for the RY1 pro forma test period, and the total natural gas revenue requirement need of $17,293,000.

B. RATE YEAR 2 – PRO FORMA STUDY

Q. Please now turn to page 13 of Exh. KJS-2 and Exh. KJS-3 and explain what the columns there represent.

A. Starting on page 13 of Exh. KJS-2 (electric) and Exh. KJS-3 (natural gas) begins the incremental adjustments for RY2, that are necessary to adjust the pro forma operating results for RY1 (representing the RY1 electric and natural gas Pro Forma Studies), to produce the electric and natural gas Pro Forma Studies for RY2.

Individual RY2 "Pro Forma" adjustments, start in column (5.00) through (5.06) on page 13, for both electric and natural gas. Additional electric only RY2 pro forma adjustments, column (5.09) through (5.12), continue on page 14 of Exh. KJS-2. These adjustments pro form incremental costs expected in RY2, above RY1 levels, beginning December 2025.

Individual RY2 "Provisional" adjustments, for electric begin on page 13 in column (5.07) and continue through column (5.08) on page 14, and for natural gas, begin on page 14 in column (5.07) through column (5.08). These adjustments reflect incremental "provisional" costs expected in RY2, beginning December 2025, impacting related pro forma expenses, as well as net plant that are subject to review and refund in a future period. Each of these adjustments are described below.

<u>1.) RY2 Pro Forma Adjustments</u>

Q. Starting on page 14 for electric and 12 for natural gas, would you please discuss the RY2 <u>pro forma</u> adjustments?

A. Yes. Starting on page 13 for electric and natural gas, pro forma adjustments reflect the incremental increases in expenses and rate base adjustments for RY2, effective December 2025 through December 2026, above RY1 pro forma levels.

The first RY2 pro forma <u>electric only</u> adjustment, **<u>Pro Forma Power Supply – Remove Colstrip (Electric)</u>**, column (5.00P), as discussed by Mr. Kalich, effective with the RY2 incremental base rate increase, the Company is proposing to revise net power supply costs and the ERM baseline to reflect the mandated removal of Colstrip by January 1, 2026. The net effect to Washington electric of Pro Forma Adjustment 5.00P, increases the Company's requested revenue requirement by $59.5 million in RY2, solely due to removing the net impact of Colstrip net power supply costs. The net impact of this adjustment decreases NOI by $44,781,000.

The next RY2 pro forma adjustment (first natural gas pro forma adjustment), **<u>Pro Forma AMI Regulatory Amortization</u>**, column (5.01), adjusts the electric and natural gas AMI Regulatory Asset balances and O&M expenses from that included in RY1 (per Adjustment 3.04 above). Washington O&M expense is <u>reduced</u> an incremental $314,000 for electric and $105,000 for natural gas to reflect incremental O&M savings in RY2 beyond RY1 levels. In addition, the Regulatory AMI Asset (Deferred Debits) balances are decreased $3.0 million for electric and $0.8 million for natural gas, to reflect the reduced regulatory asset balances during RY2 on an AMA basis, due to the amortization of the AMI Regulatory Asset. The net effect of these adjustments, therefore, increases NOI by $232,000 for electric and $78,000 for natural gas. This adjustment also reduces total rate base by $2,992,000 for electric and $848,000 for natural gas.

<u>Pro Forma Non-Exec Labor & Union Incentive,</u> column (5.02) electric and natural gas, reflects incremental union and non-union wages and salaries from RY1 (included in Pro Forma Labor Non-Exec adjustment (3.05)) to RY2 (excludes executive salaries). For <u>non-union</u> and <u>union</u> employees, wages and salaries were adjusted to annualize the estimated increase applied in RY1 for the March 2025 increase, and includes the prorated salary increase expected, effective March 1, 2026, for non-union employees, and March 26, 2026, for union employees. The net effect of this adjustment on NOI is a decrease of $2,087,000 electric and $581,000 natural gas.

<u>Pro Forma Employee Benefits</u>, column (5.03) electric and natural gas, adjusts the incremental changes in Retirement Plans (401(k) and Pension), and Medical insurance for active employees and for those retired (post-retirement medical) to the expected amount for the RY2 rate effective period, above RY1 levels. (See discussion in adjustment (3.07) above.) The impact of these changes is summarized in Table No. 11 below:

<u>Table No. 11: Benefit Adjustment RY2</u>

Benefit Adjustment	RY2			
	System	System O&M	WA Electric	WA Natural Gas
Medical	$ 1,210,622	$ 708,819	$ 332,685	$ 105,310
Retirement	476,745	279,134	131,012	41,471
Total	$ 1,687,367	$ 987,953	$ 463,697	$ 146,781

[1] Includes effects of the pension settlement exclusion

As shown in Table No. 11 above, the overall net impact of the incremental changes in pension and medical expense on a system O&M expense basis in RY2, above RY1 levels, is an increase of $988,000, or $464,000 Washington electric and $147,000 Washington natural gas. Therefore, Pro Forma Employee Benefits adjustment (5.03) decreases NOI for electric by $366,000 and for natural gas by $116,000. Again, the Company will update the level of expense as soon possible during the process of the case, after receiving updated consultant information expected in early 2024.

Pro Forma Property Tax, column (5.04) electric and natural gas, restates the RY1 level of property tax expense included in adjustment (3.11) Pro Forma Property Tax for RY1, to the level of property tax expense the Company will experience during RY2. The property on which the tax is calculated is the property value as of December 31, 2022, taxed at existing rates. The property tax balances include estimates for 2023-2026 and the Company will update with more current estimates through the process of the case. The effect of this adjustment decreases NOI by $590,000 for electric and by $24,000 for natural gas.

Pro Forma Nucleus/ETRM Expense, column (5.05) electric and natural gas, adjusts the RY1 level of Nucleus/Energy Trade and Risk Management (ETRM) expense as included in adjustment (3.19) Pro Forma Nucleus/ETRM expense, to the level expected in RY2. As discussed by Mr. Kinney, in 2026, $0.76 million (system) in expense is needed to support vendor and system integrator costs, and incremental labor associated with the implementation and the support of the Nucleus application, thus, reducing expense $207,000 Washington electric and $65,000 Washington natural gas, from expected RY1 levels as established in Adj. 3.19 – Pro Forma Nucleus/ETRM expense. The effect of this adjustment increases NOI by $164,000 for electric and by $51,000 for natural gas.

Pro Forma Misc. O&M Expense, column (5.06), electric and natural gas, as discussed by Ms. Andrews, reflects escalated increases in certain Company O&M and A&G expenses, to reflect incremental expenses in RY2, beyond RY1 levels, effective December

2025, through December 2026, not otherwise pro formed within the Company's electric or natural gas Pro Forma Studies. The same escalation growth rate of 6.3% for electric and 4.57% for natural gas operations used in RY1, applied by FERC account to certain O&M and A&G annual balances as of RY1, is used to escalate RY2 above RY1 levels. This adjustment increases RY2 Washington expenses by $3,550,000 for electric and $653,000 for natural gas and decreases RY2 Washington NOI by $2,805,000 for electric and $516,000 for natural gas.

Q. Turning to page 14 of electric Exh. KJS-2, please discuss the final four electric RY2 pro forma adjustments.

A. The final four (electric only) RY2 pro forma adjustments begin with **Pro Forma EDIT (Electric)**, column (5.09). As discussed by Ms. Andrews, this adjustment reflects the incremental adjustment to Washington electric EDIT for the impact of removing Colstrip excess DFIT from base rates prior to January 1, 2026. (The level of EDIT expense remains the same for natural gas over the Two-Year Rate Plan.) The effect of this adjustment increases electric deferred tax expense and decreases NOI by $767,000 in RY2 above RY1 levels.

Pro Forma Transportation Electrification Return (Kicker) (Electric), column (5.10), includes the 2% incentive rate of return (return "kicker") for RY2 on the Transportation Electrification capital investments included in this case, above RY1 levels discussed above in PF adjustment (3.21), which totals approximately $27,000 in Rate Year 2 (2024). Grossed up for taxes, the amount included in Exh. KJS-2, page 14, column (5.10) totals $36,000 for RY2. The impact on electric NOI for this adjustment is a decrease of $28,000.

Pro Forma CS2 Amortization (Electric), column (5.11), as discussed by Ms. Andrews, reflects the deferral and amortization expense in RY2 associated with Washington's share of the Company's proposed CS2 major maintenance expense deferral of approximately $12.0 million ($18.5 million (system) overhaul scheduled for June 2026), and amortizing the deferred balance over a 4-year period beginning July 1, 2026 through June 30, 2030 (see Ms. Andrew's Section VI. "2026 CS2 Deferral of Major Maintenance and Recovery" in Exh. EMA-1T). The effect of this adjustment increases Washington electric RY2 amortization expense by $1,661,000 and decreases NOI by $1,312,000.

The final RY2 pro forma adjustment, electric only, on page 14 of Exh. KJS-2 is adjustment **Pro Forma PPA Interest Expense (Electric)**, column (5.12). This adjustment reflects the recovery of interest in RY2 on Washington's share of certain 2024 - 2026 Power Purchase Agreements (PPAs) above RY1 levels. As discussed by Mr. Kinney, pursuant to RCW 80.28.410(2)(b), the Company has included interest on qualifying PPAs (Chelan, Clearwater III and Columbia Basin Hydro) at the Company's proposed rate of return in this general rate case of 7.61%. For RY2, the Company has included $2.34 million of total PPA interest, resulting in an incremental interest amount of $176,000 above RY1 levels. The net impact of this adjustment decreases Washington electric NOI by $139,000.

2.) RY2 Provisional Adjustments

Q. Turning now back to page 13 and continuing on page 14 of Exh. KJS-2 for electric, and remaining on page 14 of Exh. KJS-3 for natural gas, please explain what the columns there represent.

A. Starting on page 13, the last column, of Exh. KJS-2 (electric), and page 14, the first column of Exh. KJS-3 (natural gas) begins the incremental "provisional" adjustments for RY2, that are necessary to adjust the Pro Forma operating results for RY1 (representing the RY1 electric and natural gas Pro Forma Studies), to produce the final electric and natural gas Pro Forma Studies for RY2.

The first RY2 provisional adjustment is **Provisional Capital Additions to 12.31.2026 AMA,** column (5.07), for electric and natural gas. This adjustment, sponsored by Ms. Benjamin, is composed of three parts. The first component adjusts plant-in-service at December 31, 2025 AMA balances to December 31, 2026 AMA balances by extending A/D and ADFIT balances. The second component reflects the impact of retirements from December 31, 2025 AMA balances to December 31, 2026 AMA balances. The third component reflects additions to plant-in-service, inclusive of new growth capital, between December 31, 2025, on an AMA basis and December 31, 2026, on an AMA basis, inclusive of the depreciation expense, A/D, and ADFIT associated with these additions for the period. This adjustment also adjusts depreciation expense to reflect the appropriate level of expense at December 31, 2026.

The net impact of this adjustment on electric increases net rate base by $93,236,000 and decreases NOI by $2,479,000. For natural gas, this adjustment increases net rate base by $17,089,000 and decreases NOI by $1,282,000. Detailed information supporting these capital additions are included in testimony and exhibits of witnesses Mr. Alexander, Mr. DiLuciano, Mr. Manuel, Mr. Howell, and Ms. Hydzik. Details supporting this adjustment is available in Exh. TCB-2 (native version) provided with this filing, as well as in Ms. Benjamin's workpapers provided to all Parties after filing of this case.

Turning to page 14 of Exh. KJS-2 and remaining on page 14 of Exh. KJS-3, the next, and final "provisional" adjustment for electric and natural gas, is **Provisional 2026 Capital Additions O&M & Revenue Offsets,** column (5.08). As discussed by Ms. Andrews, and further described at Exh. EMA-1T Section V. "Pro Forma Offsetting Factors – Direct & Indirect," this adjustment reflects additional offsets and revenues recorded in RY2 above RY1 levels for: 1) direct O&M savings, 2) an incremental "2% O&M efficiency" adjustment where applicable, and 3) offsetting revenue associated with the New Revenue – Growth Capital Business Case, in RY2. These direct O&M offsets, "2% efficiency" O&M offsets and revenues are shown in detail in Ms. Andrews Exh. EMA-3. The net impact of this adjustment for electric increases revenues by $3,014,000, decreases expense $830,000 and increases NOI by $3,037,000. For natural gas, this adjustment increases revenues by $39,000, decreases expense $201,000 and increases NOI by $190,000.

Q. Completing the electric and natural gas Pro Forma Studies for RY2, please discuss the final two columns on page 14 of Exh. KJS-2 and Exh. KJS-3.

A. For electric, the final two columns on page 14 of Exh. KJS-2, reflects the RY2 total column labeled "RY2 12.2025 FINAL TOTAL," showing the RY2 total pro forma operating results (NOI of $65,862,000) and rate base ($2,400,061,000) for the RY2 pro forma test period, and the total electric revenue requirement need of $155,197,000 over the Two-Year Rate Plan, and the final column labeled "RY2 Incremental 12.2025-I FINAL TOTAL," showing the incremental revenue requirement in RY2, above RY1, of $78,130,000.

For natural gas, the final two columns on page 14 of Exh. KJS-3, reflect the RY2 total column labeled "RY2 12.2025 FINAL TOTAL," showing the RY2 total pro forma operating results (NOI of $29,386,000) and rate base ($602,325,000) for the RY2 pro forma test period, and the total electric revenue requirement need of $21,857,000 over the Two-Year Rate Plan, and the final column labeled "RY2 Incremental 12.2025-I FINAL TOTAL," showing the incremental revenue requirement in RY2, above RY1, of $4,565,000.

C. RY1 and RY2 Final Summary

Q. How much additional net operating income would be required for Washington electric operations to allow the Company an opportunity to earn its proposed 7.61% rate of return on a pro forma basis for the Two-Year Rate Plan?

A. For electric, the net operating income deficiency amounts to $57,991,000 for RY1 and $58,791,000 (incremental) for RY2, as shown on line 5, page 3 of Exh. KJS-2. The resulting revenue requirement is shown on line 7 and amounts to $77,067,000 for RY1, or a base increase of 13.0% (12.6% billed), and $78,130,000 (incremental) for RY2, or a base increase of 11.7%. After taking into account the Colstrip Tariff Schedule 99 offset, the proposed RY2 billed electric increase is $53.711 million or 7.8%.

Q. How much additional net operating income would be required for the Washington natural gas operations to allow the Company an opportunity to earn its proposed 7.61% rate of return on a pro forma basis for the Two-Year Rate Plan?

A. For natural gas, the net operating income deficiency amounts to $13,015,000 for RY1 and $3,436,000 (incremental) for RY2, as shown on line 5, page 3 of Exh. KJS-3. The resulting revenue requirement is shown on line 7 and amounts to $17,293,000 for RY1, or a base increase of 13.6% (6.3% billed), and $4,564,000 (incremental) for RY2, or an increase of 3.2% (1.6% billed).

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

A. Yes, it does.