DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL FOR
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-16-03
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	DIRECT TESTIMONY
TO ELECTRIC CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	ELIZABETH M. ANDREWS
	)	

FOR AVISTA CORPORATION

(ELECTRIC)

I. INTRODUCTION

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

A. My name is Elizabeth M. Andrews. I am employed by Avista Corporation as Senior Manager of Revenue Requirements in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you please describe your education and business experience?

A. I am a 1990 graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. That same year, I passed the November Certified Public Accountant exam, earning my CPA License in August 1991[1]. I worked for Lemaster & Daniels, CPAs from 1990 to 1993, before joining the Company in August 1993. I served in various positions within the sections of the Finance Department, including General Ledger Accountant and Systems Support Analyst until 2000. In 2000, I was hired into the State and Federal Regulation Department as a Regulatory Analyst until my promotion to Manager of Revenue Requirements in early 2007 and Senior Manager in early 2016. I have also attended several utility accounting, ratemaking and leadership courses.

[1] Currently I keep a CPA-Inactive status with regards to my CPA license.

Q. Would you briefly describe your responsibilities?

A. Yes. As Senior Manager of Revenue Requirements, I am responsible for the preparation of normalized revenue requirement and pro forma studies for the various jurisdictions in which the Company provides utility services. During the last fifteen years, I have led or assisted in the Company's electric and/or natural gas general rate filings in Idaho, Washington and Oregon.

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 rate request and the need for the proposed increase in rates for 2017. I will explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base. In addition, I incorporate the Idaho share of the proposed adjustments of other witnesses in this case.

A table of contents for my testimony is as follows:

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

A. Yes. I am sponsoring Exhibit No. 11, Schedule 1, which was prepared by me. This exhibit consists of worksheets, which show actual twelve months ended December 31, 2015 operating results, and pro forma and proposed electric operating results and rate base for the State of Idaho for the 2017 rate year. The exhibits also show the calculation of the general revenue requirement, 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 pro forma adjustments proposed in this filing for 2017.

II. REVENUE REQUIREMENT SUMMARY – 2017 Rate Year

Q. Please summarize the results of the Company's Idaho electric pro forma study.

A. After taking into account all standard Commission Basis adjustments[2], as well as additional pro forma and normalizing adjustments, the pro forma electric rate of return ("ROR") for the Company's Idaho jurisdictional operations is 6.53% for rate year 2017. This return level

[2] "Commission Basis" adjustments are defined as individual normalizing and restating adjustments that are standard components of general rate case filings previously approved by the Idaho Public Utility Commission (IPUC).

is well below the Company’s requested rate of return of 7.78% for the 2017 rate year.

The incremental revenue requirement necessary to provide the Company an opportunity to earn its requested ROR in rate year 2017 is $15,433,000 for its electric operations. The overall 2017 base electric increase associated with this request is 6.34%.

Q. What is the Company’s rate of return that was last authorized by this Commission for its electric operations in Idaho?

A. The Company’s last authorized rate of return for its Idaho electric operations was 7.42%, effective January 1, 2016 for our electric system.

Q. What are the primary factors driving the Company’s need for an electric increase?

A. The primary factor (approximately 77%) driving the Company’s electric revenue requirement in 2017 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. As discussed further below, in 2017 net power supply expenses also contribute to the incremental revenue requirement (approximately 12%).

The remaining increase impacting the Company’s revenue requirement request (approximately 11%) relates to net increases in operation and maintenance (O&M) and administrative and general (A&G) expenses for Avista's electric operations compared to current authorized levels, mainly due to increased labor and benefits.

To recognize these cost changes, the Company has included a number of 2017 pro forma adjustments to capture the net increases the Company will experience from the 2015 test year.

Q. What are the major components of the increased net plant investment included in the Company's 2017 electric results?

A. Looking at the changes to "gross" plant in service for 2017, Idaho electric "gross" plant increases by approximately $96.0 million, as compared to what was approved in the last general rate case for new retail rates effective January 1, 2016.

In order to meet the energy and reliability needs of our customers, $52.0 million of the electric "gross" plant increase is due to the Company's investment in thermal and hydro generating facilities, as well as additional transmission investment. Electric distribution "gross" plant increases $25.9 million above that approved in the last general rate case. The electric portion of general and intangible "gross" plant increases $18.1 million.

The specific 2016 through 2017 pro forma capital expenditures undertaken by the Company to expand and replace its generation, transmission and distribution facilities are discussed further by Company witnesses Mr. Kinney regarding production assets, Mr. Cox regarding transmission assets, Ms. Rosentrater regarding electric distribution assets, and Mr. Kensok regarding the costs associated with Avista's Information Service/Information Technology (IS/IT) projects. Company witness Ms. Schuh describes the Company's general plant additions for 2016 and 2017.

The Company is making substantial new investment in its electric system infrastructure to address the replacement and maintenance of Avista's aging system, and to sustain reliability and safety. As soon as this new plant is placed in service, the Company must start depreciating the new plant investment. Unless this new investment is reflected in retail rates in a timely manner, it has a negative impact on Avista's earnings, particularly because the new plant is typically far more costly to install than the cost of the plant that was embedded in rates decades earlier. As plant is completed and is providing service to customers, it is appropriate for the Company to receive timely recovery of the costs associated with that plant.

Q. Please provide an overview of the changes in net power supply expenses.

A. As discussed in Company witness Mr. Johnson's testimony, the level of Idaho's share of power supply expense for 2017 has increased by approximately $5.3 million ($15.6 million on a system basis) from the level currently included in base rates. The increase in 2017 net power supply expense is mainly related to the inclusion of the Palouse Wind power purchase agreement[3] and the expiration of a capacity sales agreement with Portland General Electric on December 31, 2016, partially offset by reduced natural gas prices.

III. DERIVATION OF 2017 REVENUE REQUIREMENT

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

A. The test period being used by the Company is the twelve-month period ending December 31, 2015, presented on a 2017 pro forma average-of-monthly-averages (AMA) basis. Currently authorized rates, effective January 1, 2016, were based upon the twelve-months ending December 31, 2014 test year utilized in case AVU-E-15-05, adjusted on a pro forma basis.

[3] Currently, the Palouse Wind purchase is recovered through the Power Cost Adjustment (PCA), as discussed by Mr. Johnson.

<u>Revenue Requirement - 2017</u>

Q. Would you please explain what is shown in Exhibit No. 11, Schedule 1?

A. Yes. Exhibit No. 11, Schedule 1, shows actual and pro forma 2017 electric operating results and rate base for the State of Idaho.

Column (b) of page 1 of Exhibit No. 11, Schedule 1, shows December 31, 2015 actual operating results and components of the AMA rate base as recorded; column (c) is the total of all adjustments to net operating income and rate base to reflect 2017 results; and column (d) is the 2017 pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn a 7.78% rate of return for 2017. Column (f) reflects 2017 pro forma operating results with the requested increase of $15,433,000 for electric operations.

Q. Would you please explain page 2 of Exhibit No. 11, Schedule 1?

A. Yes. Page 2 of Exhibit No. 11, Schedule 1, shows the 2017 revenue requirement calculations for electric operations of $15,433,000 at the requested 7.78% rate of return.

Q. What does page 3 of Exhibit No. 11, Schedule 1 show?

A. Page 3 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital of 7.78%. Company witness Mr. Thies 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.

Q. Would you now please explain page 4 of Exhibit No. 11, Schedule 1?

A. Yes. Page 4 shows the derivation of the net-operating-income-to-gross-revenue-conversion factor. The conversion factor takes into account uncollectible accounts receivable, Commission fees and Idaho State income taxes. Federal income taxes are reflected at 35%.

Q. Now turning to pages 5 through 9 of Exhibit No. 11, Schedule 1, please explain what those pages show?

A. Page 5 begins with actual operating results and rate base for the test period in column (1.00). Individual Commission Basis normalizing and restating adjustments that are standard components of general rate case filings begin on page 5, in column (1.01) and continue through column (2.13) on page 7.

Individual pro forma adjustments for 2017 begin in column (3.01) on page 8 and go through column (3.07) on page

9, with the "2017 FINAL TOTAL" column on page 9 representing the total pro forma operating results and net rate base for the 2017 pro forma period.

IV. STANDARD COMMISSION BASIS AND RESTATING ADJUSTMENTS

Q. Please explain each of the standard Commission basis and restating adjustments?

A. Yes, but before I begin, I will note that the following electric adjustments are consistent with current regulatory principles and the manner in which they have been addressed in recent cases (i.e., AVU-E-15-05), unless otherwise noted. Columns following the Results of Operations column (1.00) reflect restating adjustments necessary to: restate the actual results based on prior Commission orders; reflect appropriate annualized expenses and rate base; correct for errors; or remove prior period amounts reflected in the actual results of operations.

In addition to the explanation of adjustments provided herein, the Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments.

A summary of each adjustment follows:

Adjustment (1.01) - **Deferred FIT Rate Base**, adjusts the 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 my workpapers provided with the Company's filing.

ADFIT reflects the deferred tax balances arising from accelerated tax depreciation (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated Cost Recovery, or MACRS, repairs deduction and bonus depreciation), bond refinancing premiums, and contributions in aid of construction.

The increase in ADFIT (which is a reduction of rate base) included in this adjustment is primarily due to the annualizing of tax depreciation adjustments for the repairs deduction and bonus depreciation related to the 2015 federal tax return. This adjustment restates ADFIT to reflect the impact of both tax deductions as if they had been recorded beginning in January 2015.

The effect of these adjustments on Idaho rate base is a reduction of $6,802,000. The effect on Idaho net operating income (NOI) due to the Federal Income Tax (FIT) expense on the restated level of interest on the change in rate base[4] is a reduction of $67,000.

Adjustment (1.02) - **Deferred Debits, Credits and Regulatory Amortizations**, is a consolidation of previous

[4] The net effect of FIT expense on the restated level of interest expense due to a change in rate base is shown within each individual adjustment.

Commission Basis or other restating rate base adjustments and their NOI impact. The net impact on a consolidated basis of this adjustment decreases Idaho electric rate base by $581,000 and decreases NOI by $1,901,000.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 2015 actual results (included in column 1.00 “Per Results of Operations”), based on prior Commission orders as explained below.

- **<u>Colstrip 3 AFUDC Elimination</u>** is a reallocation of rate base and depreciation expense between jurisdictions. In Cause Nos. U-81-15 and U-82-10, the Washington Utilities and Transportation Commission (WUTC) allowed the Company a return on a portion of Colstrip Unit 3 construction work in progress (CWIP). A much smaller amount of Colstrip Unit 3 CWIP was allowed in rate base in Case No. U-1008-144 by the Idaho Public Utility Commission (IPUC). The Company eliminated the AFUDC associated with the portion of CWIP allowed in rate base in each jurisdiction. Since production facilities are allocated on the Production/Transmission formula, the allocation of AFUDC is reversed and a direct assignment is made. The effect on rate base is a decrease of $206,000 to reflect the correct level of rate base at December 31, 2015 (AMA).

- **<u>Colstrip Common AFUDC</u>** is also associated with the Colstrip plants in Montana, and increases rate base. Differing amounts of Colstrip common facilities were excluded from rate base by this Commission and the WUTC until Colstrip Unit 4 was placed in service. The Company was allowed to accrue AFUDC on the Colstrip common facilities during the time that they were excluded from rate base. It is necessary to directly assign the AFUDC because of the differing amounts of common facilities excluded from rate base by this Commission and the WUTC. In September 1988, an entry was made to comply with a Federal Energy Regulatory Commission (FERC) Audit Exception, which transferred Colstrip common AFUDC from the plant accounts to

Account 186. These amounts reflect a direct assignment of rate base for the appropriate average-of-monthly-averages amounts of Colstrip common AFUDC to the Washington and Idaho jurisdictions. Amortization expense associated with the Colstrip common AFUDC is charged directly to the Washington and Idaho jurisdictions through Account 406 and is a component of the actual results of operations.

- **Kettle Falls & Boulder Park Disallowances** reflect the Kettle Falls generating plant disallowance ordered by this Commission in Case No. U-1008-185 and the Boulder Park plant disallowance ordered by the IPUC in Case No. AVU-E-04-1. The IPUC disallowed a rate of return on $3,009,445 of investment in Kettle Falls, and $2,600,000 million of investment in Boulder Park. The disallowed investment, and related accumulated depreciation and accumulated deferred taxes are removed. These amounts are a component of actual results of operations.

- **Restating CDA Settlement Deferral** adjusts the net assets and DFIT balances associated with the 2008/2009 past storage and §10(e) charges deferred for future recovery as recorded to a 2017 AMA basis, and records the annual amortization expense based on a ten-year amortization, as approved in Case No. AVU-E-10-01. The effect on rate base is a decrease of $40,000 to reflect the correct level of rate base at December 31, 2017 (AMA).

- **Restating Spokane River Deferral** adjusts the net asset and DFIT balances related to the Spokane River deferred relicensing costs as recorded to a 2017 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01. The effect on rate base is a decrease of $8,000 to reflect the correct level of rate base at December 31, 2017 (AMA).

- **Restating Spokane River PM&E Deferral** adjusts the net asset and DFIT balances related to the Spokane River deferred PM&E costs as recorded to a 2017 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01. The effect on rate base is a decrease of $35,000 to reflect the correct level of rate base at December 31, 2017 (AMA).

- **Restating Montana Riverbed Lease** adjusts the net asset and DFIT balances reflected in results of operations related to the costs associated with the Montana Riverbed lease settlement deferred for recovery to a 2017 AMA basis. In the Montana Riverbed lease settlement, the Company agreed to pay the State of Montana $4.0 million annually beginning in 2007, with annual inflation adjustments, 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 Case No. AVU-E-07-10. In Case No. AVU-E-08-01 (see Order No. 30647), 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 October 1, 2008. The 10-year amortization of the first two annual payment deferral expires on September 31, 2016. Therefore, the adjusted rate base balance during 2017 is $0. This restating adjustment removes the rate base amount included in the test period, reducing rate base by $293,000. The Company has included lease expense, increased for annual inflation, as previously required. The net effect of the expiration of the deferral amortization, offset in part, by the increase in inflation on the lease expense, decreases Idaho expense by $234,000.

- **Weatherization and DSM Investment** includes in rate base the Sandpoint weatherization grant balance (FERC account 124.350). Beginning in July 1994 accumulation of AFUCE[5] ceased on Electric DSM and full amortization began on the balance based on the measure lives of the investment. Beginning in 1995 the amortization rates were accelerated to achieve a 14 year weighted average amortization period, which was completed in 2010. Remaining as an Idaho rate base item is the weatherization loan balance of approximately $60,200.

- **Customer Advances** decreases rate base for moneys advanced by customers for line extensions, as they will be recorded as contributions in aid of construction at some future time.

- **Amortization of Reardan** removes the amortization expense included in the 2015 test period. In May 2008, Avista purchased the Reardan Wind Project Site from

[5] Allowance for funds used to conserve energy.

Energy Northwest, the then-current developer, after it was demonstrated as the Company's least-cost option for securing a renewable resource for its customers, consistent with its 2007 Integrated Resource Plan. Avista later chose to delay the construction of the Reardan project and take advantage of much-lower costs for wind projects that emerged in 2011 (Palouse Wind). Avista recorded approximately $4.0 million of site acquisition and preparation costs, of which $1.747 million was Idaho's share. In Case No. AVU-E-12-08, the Commission approved a two-year amortization of the deferral balance beginning April 1, 2013 through March 31 2015. This portion of the adjustment decreases Idaho expense by $217,000.

- **Amortization of Lake Spokane Deferral** includes the amortization expense in 2017 to reflect the three-year amortization of the deferred costs related to improving dissolved oxygen levels in Lake Spokane. In Case No. AVU-E-13-05 (see Order No. 32917), the Company received approval of an Accounting Order to defer the costs related to the improvement of dissolved oxygen levels in Lake Spokane. Order No. 32917 authorized the Company to defer and transfer Idaho's share of these costs (approximately $473,000) to FERC account 182.3 (Other Regulatory Assets) for later recovery, with no carrying charge. A three-year amortization of the deferral balance beginning January 1, 2016 through December 31, 2018 was approved in Case No. AVU-E-15-05. The net effect of this adjustment increases expense by $154,000.

- **Amortization of Colstrip Deferral** reflects the two-year amortization of the deferred revenues received from insurance proceeds related to the Colstrip lawsuit settlement funds received in 2014. The two-year amortization schedule is consistent with expenses associated with the Colstrip lawsuit settlement payments made in 2008 previously deferred and amortized over two-years in Idaho's jurisdiction. The two-year amortization of the deferral balance beginning January 1, 2016 through December 31, 2017 was approved in Case No. AVU-E-15-05. The net effect of this adjustment decreases amortization expense by $200,000.

- **Amortization of Project Compass Deferral** includes the 2017 amortization expense associated with the three-year amortization of 80% of the deferred electric revenue requirement amounts associated with the Company's Project Compass Customer Information System

(Project Compass) for calendar year 2015. In Case No. AVU-E-14-05, the Commission approved an all-party settlement, in which the Parties agreed that eighty-percent (80%) of the revenue requirement associated with Project Compass during 2015, beginning the month the Project goes into service, would be deferred, without a carrying charge, for recovery in a future proceeding. This project was moved into service on February 2, 2015. A Three-year amortization of the deferral balance beginning January 1, 2016 through December 31, 2018 was approved in Case No. AVU-E-15-05. The net effect of this adjustment increases amortization expense by $891,000. This adjustment also removes the deferral of the O&M expense recorded during the 2015 test period, increasing O&M expense by $2,674,000.

The net effect of each of these adjustments increased Idaho electric expenses by $2.9 million, decreasing NOI by $1,901,000 and decreasing total rate base by $581,000.

Adjustment (1.03) - **Restate Capital 2015 EOP**, restates the capital investment and expenses associated with adjusting the 2015 average-of-monthly-average (AMA) plant related balances to December 31, 2015 end-of-period (EOP) balances. The effect on Idaho results increases rate base by $18,731,000, and increases NOI by $186,000 related to the federal income tax effect of debt interest.

Adjustment (1.04) - **Working Capital**, adjusts the working capital rate base amount from the amount included in the Results of Operations column (1.00) to the 2015 AMA test period amount calculated using the Investor Supplied Working Capital (ISWC) method.

Working capital represents the funds necessary to cover the lag in time between the collection of revenues for services rendered, and the necessary outlay of cash by the Company to pay the expenses of providing those services. The working capital included in the Results of Operations at December 31, 2015, however, was only Idaho's portion of the 2015 average-monthly-average balances of FERC accounts 151 (Fuel Stock Inventory) and 154 (Plant Materials & Supplies). The Company, therefore, updated working capital using the ISWC method. This approach is consistent with that included and reviewed by the parties in Case No. UE-15-05[6].

In addition to updating working capital using the ISWC methodology, it was also revised to reflect the tax depreciation impact (related to repairs and bonus depreciation) on ADFIT, impacting current taxes payable through December 31, 2015. The net effect of adjustments to Working Capital from that recorded per results of operations at December 31, 2015, increases net rate base by $15,563,000[7] and increases NOI by $154,000 due to the FIT expense of the restated level of interest on the change in rate base.

[6] The ISWC calculation is also consistent with that approved in Avista's Washington jurisdiction.
[7] An increase of $2.9 million above that currently authorized for the 2016 rate year using the ISWC method in Case No. AVU-E-15-05.

Q. Please continue with your discussion of the restating adjustments included in Exhibit No. 11, Schedule 1.

A. Adjustment (1.05) – **Plant Held for Future Use (PHFFU)**, adds certain property to rate base that the Company owned at the time of this filing that has been recorded as held for future use. Prior to 2015, the Company's investment in PHFFU has been relatively small. The Company is proposing to include in rate base property for which the Company has specific plans for how the property will be used. Specifically, the Company has included two parcels of land; one of the parcels is for a future substation (Idaho's share is approximately $150,000) and one of the parcels is for a future natural gas-fired combustion turbine (Idaho's share is approximately $1.23 million).

Q. Why is it appropriate to include this investment in rate base?

A. The Company purchases certain property to meet a specific utility purpose. For the property referenced above, the location of the property and its proximity to other Avista assets warranted the purchase early, well before the actual construction of the substation or generating plant. Securing the property in advance at a reasonable cost ensures that this property in the correct location is available for the planned future facilities. It is appropriate for Avista to include the property in rate base and earn a return on the investment.

The net effect of this adjustment increases rate base by $1,383,000 and increases NOI by $14,000 due to the FIT expense of the restated level of interest on the change in rate base.

Q. Please continue with your discussion of the restating adjustments included in Exhibit No. 11, Schedule 1.

A. Adjustment (2.01) - **Eliminate B & O Taxes**, eliminates the revenues and expenses associated with local business and occupation (B & O) taxes, which the Company passes through to its Idaho customers. The effect of this adjustment decreases electric NOI by $10,000.

Adjustment (2.02), starting on page 6 of Exhibit No. 11, Schedule 1 - **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment decreases electric NOI by $104,000.

Adjustment (2.03) - **Regulatory Expense**, restates recorded test period regulatory expense to reflect the IPUC assessment rates applied to test period revenues, and the actual levels of FERC fees paid during the test period. The effect of this adjustment decreases electric NOI by $9,000.

Adjustment (2.04) - **Injuries and Damages**, is a restating adjustment that replaces the accrual with the six-year rolling average of actual injuries and damages payments not covered by insurance. This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11, and has been used since that time. The effect of this adjustment increases electric NOI by $7,000.

Adjustment (2.05) **FIT/DFIT/ITC/PTC Expense**, adjusts the FIT and DFIT expenses calculated at 35% within Results of Operations, as needed, by reflecting the appropriate Schedule M items and jurisdictional allocation of these Schedule M items as compared to Results of Operations. In addition, this adjustment records the appropriate level of production tax credits and income tax credits on qualified electric generation.

The net tax effect of this adjustment decreases Idaho electric NOI by $413,000.

Adjustment (2.06) - **SIT/SITC Expense**, adjusts Idaho State Income Tax (SIT) expense and Idaho State Investment Tax Credits (SITC) applicable to Idaho electric operations as recorded. This approach is consistent with that included and reviewed by the parties in Case No. UE-15-05. The effect on Idaho electric NOI is an increase of $151,000.

Adjustment (2.07) - **Revenue Normalization**, is an adjustment taking into account known and measurable changes that include 1) revenue normalization which reprices customer usage using the current authorized base rates (approved in Case No. AVU-E-15-05 effective January 1, 2016), 2) weather normalization, and 3) an unbilled revenue calculation. Schedule 91 Tariff Rider, Schedule 97 BPA Settlement Rebate and Schedule 59 Residential Exchange are excluded from pro forma revenues, and the related amortization expense is eliminated as well.

Company witness Ms. Knox sponsors this adjustment. The effect of this adjustment increases electric NOI $3,635,000.

Adjustment (2.08) - **Miscellaneous Restating** removes a number of non-operating or non-utility expenses associated with advertising, dues and donations, etc., included in error, and removes or restates other expenses incorrectly charged between service and or jurisdiction. In addition, this adjustment reflects 2014 retroactive union salary increases paid in 2015 above that accrued in September and December of 2014[8]. The net effect of this adjustment increases electric NOI by $24,000.

Adjustment (2.09), starting on page 7 of Exhibit No. 11, Schedule 1 - **Restate Incentives**, restates the actual employee payroll incentives included in the Company's test period using a six-year average payout percentage.

For officers, the incentive amount included in the Company's filing is based on the 2016 incentives to be accrued for officers (paid Q-1 of 2017), based on O&M targets.[9] This amount was then multiplied by the six-year average of actual utility percentage payouts for the years 2010-2015 (reflecting a 90.63% utility average payout).

For non-officer incentives, this is calculated by using the 2017 level of labor expense (determined in adjustment (3.03) - Pro Forma Labor Non-Exec) multiplied by the payout incentive opportunity per the Company's current incentive plan to determine the incentive payout opportunity, multiplied by the adjusted six-year average of actual percentage payouts for the years 2010-2015. The adjustment reflects a 100% incentive payout for non-officer employees[10]. The net effect of this adjustment increases electric Idaho NOI by $14,000.

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[8] The Union Contract for IBEW Local 77 expired as of March 31, 2014. No salary increases were granted effective April 1, 2014 with the understanding that once the new contract was finalized, increases would be retro-active to this date. In September and December 2014 estimated amounts were recorded to the General Ledger for the retro-active payout. A new contract was signed in January 2015 and actual retro-active pay was calculated resulting in an additional accrual of approximately $533,000 (system). In order to reflect the appropriate labor for 2015, this adjustment removes prior period labor expenses included in the 2015 test period.

[9] Officer STIP based on earnings per share targets are excluded from the proposed revenue requirement. Long-term incentives based on financial metrics (performance shares) and those short-term incentives based on earnings per share are currently borne by shareholders.

[10] The actual 6-year average payout percentage was 110.64%.

Q. Please briefly describe the Executive Short Term Incentive Plan.

A. The Short Term Incentive Plan (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 STIP is a pay-at-risk plan whereby employees are eligible to receive cash incentive pay if the stated targets are achieved.

The STIP has four operational components, plus two 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 EPS components account for 60% of the total opportunity and are broken out into 50% utility EPS and 10% non-utility EPS. Only the utility 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% related to EPS targets are currently borne by shareholders.

Q. Please provide an overview of the Company's non-executive employee incentive plan.

A. Employee compensation is a combination of base pay and pay-at-risk under the Short Term Incentive Plan (STIP). The STIP provides for a portion of compensation to be at risk contingent upon the achievement of specific goals for performance, which are designed to produce customer benefits. This tension in plan design helps incent and focus all employees on the stated customer-focused goals of cost control, customer satisfaction and reliability within the system. These metrics are designed to be reasonably achievable with strong management performance. Maximum performance levels are designed to be difficult to achieve given historical performance and forecasted results at the time the metrics are approved. Pay-at-risk plans are designed to help focus employees on stated goals that benefit customers, while at the same time functioning as an integrated component of total compensation.

In accordance with the Company's overall compensation design to align elements of incentive plans among all Company employees and executives, the non-executive employee incentive plan has essentially the same stated goals as the STIP discussed above. 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 incentive plan are as follows: 60% O & M Cost-Per-Customer, 15% Customer Satisfaction, 15% Reliability Index and 10% Response Time.

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 STIP and 40% of the executive officer STIP (excluding those metrics related to EPS targets) in this case. Because all metrics in the non-officer STIP and 40% of the Officer STIP are customer-focused and benefit customers, and because this pay-at-risk is one component of total employee compensation, it is appropriate to include the customer-focused STIP incentives in general rates. The 2015 base year already excludes the portion of officer STIP related to EPS targets. In addition, because incentive loaders follow where base salary labor dollars are charged, a portion of non-officer incentives are also already charged to non-utility accounts for those employees performing work not related to the utility.

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

A. The Executive Officer Long Term Incentive Plan (LTIP) is comprised of two components, which serve two different purposes[11]. 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 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 and Total Shareholder Return. 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 excluded the Performance Share portion of the LTIP from the retail ratemaking because it is tied to shareholder performance.

Restricted Stock Unit (RSU) awards account for 25% of the LTIP and vest based on continued service. The purpose for this portion of the plan is to provide an incentive for employees to remain employed by the Company. The long-term

[11] As with all components of the executive officer compensation, the Compensation Committee determines all material aspects of the long-term incentive reward – 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.

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 will continue to cultivate the values embedded within Avista. The Restricted Stock Unit portion of the plan is <u>included</u> in retail ratemaking because customers benefit from long-term leadership with a vested interest in the efficient operation of the Company and high customer satisfaction[12].

In addition, the Restricted Stock Units are one component of total compensation and benefits that are designed to be competitive with that offered by other similar utilities. It does <u>not</u> represent "extra" compensation over and above a competitive level of pay.

Q. Please continue with explaining the remaining restating adjustments in Exhibit No. 11, Schedule 1.

A. The next adjustment, included on page 7 of Exhibit No. 11, Schedule 1, is Adjustment (2.10) - **Idaho PCA**, which removes the effects of the accounting for the Power Cost

[12] The total CEO Long Term Incentive Plan expenses have been excluded because both the restricted stock and performance shares have financial performance-related triggers.

Adjustment (PCA). Under the PCA 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. Revenue adjustments due to the PCA and the power cost deferrals affect actual results of operations and need to be eliminated to produce normalized results. Actual revenues and power supply costs are normalized in adjustments (2.07) Revenue Normalization and (3.01) Power Supply, respectively. The effect of this adjustment increases Idaho NOI by $1,281,000.

Adjustment (2.11) - **Nez Perce Settlement Adjustment,** reflects a decrease in production operating expenses. An agreement was entered into between the Company and the Nez Perce Tribe to settle certain issues regarding earlier owned and operated hydroelectric generating facilities of the Company. This adjustment directly assigns the Nez Perce Settlement expenses to the Washington and Idaho jurisdictions. This is necessary due to differing regulatory treatment in Idaho Case No. WWP-E-98-11 and Washington Docket No. UE-991606. The effect of this adjustment increases Idaho NOI by $19,000.

Adjustment (2.12) – **Colstrip/CS2 Maintenance.** As approved in Order 32371 on September 30, 2011, (in Case Nos. AVU-E-11-01 and AVU-G-11-01), the Company deferred the nonfuel O&M costs associated with the Company's Colstrip and CS2 thermal generating plants. The deferral amount is the difference between actual costs and the authorized "Base O&M" costs for each respective year included in base rates for the years 2011 – 2015.

For calendar years 2013 through 2015, the authorized "Base O&M" expense level (established in 2013 in AVU-E-12-08) was $14.4 million (system). Each year deferred costs are amortized over a three-year period.

For 2016, in Case No. AVU-E-15-05, the system "Base O&M" cost was adjusted upward from $14.4 million to $20.4 million to better reflect O&M expenses in the future based on a five-year average for the period 2012-2016. The effect of this adjustment to the "Base O&M" cost increases O&M expense and reduces the amount of the deferral that will be required in 2016 and forward. (The O&M expense for 2017-2019 ranges from $18.8 million to $22.0 million.)

One-third of each amount deferred for calendar years 2013 through 2015, plus the additional proposed expense for the 2017 rate year, increases Idaho electric expense by approximately $2.4 million, and decreases NOI by $1,498,000.

Electric Adjustment (2.13) - **Restate Debt Interest,** restates debt interest using the Company's pro forma weighted average cost of debt 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. Thies. 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 increases electric NOI by $283,000.

As noted above, 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.

V. 2017 PRO FORMA ADJUSTMENTS

Q. Please explain the significance of the adjustments beginning at page 8 of Exhibit No. 11, Schedule 1.

A. The adjustments on pages 8 and 9 of Exhibit No. 11, Schedule 1, are pro forma adjustments that recognize the jurisdictional impacts of items that will impact the 2017 pro forma operating period.

These pro forma adjustments in 2017 encompass revenue and expense items as well as additional capital projects, bringing the operating results and rate base to the final pro forma level for the 2017 rate year on an AMA basis. The methodology behind each of these adjustments are consistent with that used in Case No. AVU-E-15-05.

In the discussion that follows, an explanation of each 2017 pro forma adjustment is provided. The Company has also provided workpapers, both in hard copy and electronic formats, outlining additional details related to each of the adjustments.

Q. Please explain each of the Pro Forma adjustments shown on pages 8 and 9 of Exhibit No. 11, Schedule 1?

A. the first column on page 8 of Exhibit No. 11, Schedule 1, is Adjustment (3.01) - **Pro Forma Power Supply.** This adjustment was made under the direction of Mr. Johnson and is explained in detail in his testimony. This adjustment includes pro forma power supply related revenue and expenses to reflect the twelve-month period January 1, 2017 through December 31, 2017, using weather normalized historical loads. Mr. Johnson's testimony outlines the system level of pro forma power supply revenues and expenses that are included in this adjustment. The adjustment in column (3.01) calculates the Idaho jurisdictional share of those figures. The net effect of this adjustment decreases electric NOI by $1,785,000.

Adjustment (3.02) - **Pro Forma Transmission Revenue/Expense**, was made under the direction of Mr. Cox and is explained in detail in his testimony. This adjustment includes pro forma transmission-related revenues and expenses to reflect the twelve-month period January 1, 2017 through December 31, 2017. The net effect of this adjustment decreases electric NOI by $101,000.

Adjustment (3.03) - **Pro Forma Labor Non-Exec**, reflects changes to 2015 test period union and non-union wages and salaries, excluding executive salaries[13].

For non-union employees, base year wages and salaries are restated to annualize the March 2015 overall actual increase of 3.0%, the March 2016 overall increase of 3.0%, and 10 months of the planned March 2017 increase of 3.0%[14].

For union employees, 2015 wages and salaries are restated to annualize the March 2015 increase, and increases of 3% for 2016 and 2017 in accordance with union contract terms. The net effect of this adjustment on Idaho's electric NOI is a decrease of $736,000.

Adjustment (3.04) - **Pro Forma Employee Benefits,** adjusts for changes in both the Company's pension and medical insurance expense and increases electric NOI by $54,000.

Q. Please describe the pension expense portion of the Employee Benefits adjustment and Idaho's share of this expense.

[13] No adjustment for executive salaries was included in the Company's case beyond that included in the historical test period level expense.

[14] A minimum increase of 3.0% for 2017 was approved by the Compensation Committee of the Board of Directors at the May 2016 Quarterly Board meeting. The actual increase will be updated at or above this minimum based on market data provided in November 2016, with an effective date in March 2017.

A. The Company's pension expense is determined in accordance with Accounting Standard Codification 715 (ASC-715), and has decreased on a system basis from approximately $32.6 million for the actual base year costs for the twelve months ended December 31, 2015, to $31.6 million for 2016. The decrease in pension expense included in this case (Idaho electric share of $136,000) is primarily due to changes in the discount rate on pension liability and expected return on assets.

The pension cost included in this case is based on actual 2015 and estimated benefit costs as of January 31, 2016 as determined in accordance with ASC-715 by an independent actuarial firm, Towers Watson. These calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other companies.

Q. Please describe the 2014 changes to the Company's retirement plan.

A. In October 2013, the Company revised the defined benefit pension plan such that, as of January 1, 2014, the plan is no longer offered to its non-union employees hired or rehired by Avista on or after January 1, 2014. A defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the defined contribution plan the Company provides a non-elective contribution as a percentage of each employee's pay based on his or her age. The defined contribution is in addition to the existing 401(k) contribution in which the Company matches a portion of the pay deferred by each participant.[15]

Q. Please describe the medical insurance and post-retirement medical expense portion of Adjustment (3.05) and Idaho's share of this expense.

A. The Company's medical insurance and post-retirement medical expense portion of these adjustments adjusts for the expected medical-related costs for 2016 above the 2015 base year. This adjustment includes costs associated with the employee and retiree medical plans and the FAS 106 expense, which records the costs associated with post retirement medical. Net medical insurance and post-retirement expense has increased on a system basis from $30.2 million for the 2015 base year to $30.6 million for 2016. The increase in 2016 represents medical trend and utilization expectations, as well as accounting for Health Care Reform mandates.

Q. Please describe the 2014 changes to the Company's medical plans.

A. In October 2013 the Company revised its health

[15] These changes for the bargaining unit will be subject to future negotiations.

care benefit plan for non-union employees hired or rehired on or after January 1, 2014. Upon retirement the Company will no longer provide a contribution towards his or her medical premiums. The Company will provide access to the retiree medical plan, but the non-union employees hired or rehired on or after January 1, 2014, will pay the full cost of premiums upon retirement. In addition, beginning January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees will be revised. The revision will result in separate health insurance premiums for each group.[16]

Q. Please continue with your discussion of the 2017 pro forma adjustments.

A. The next adjustment (3.05) – **Pro Forma Property Tax**, restates the 2015 test period accrued levels of property taxes to the 2017 rate period level using the most current information. As can be seen from my workpapers provided with the Company's filing, the property on which the tax is calculated is the property value as of December 31, 2016, reflecting the 2017 level of expense the Company will experience during the 2017 rate period. The net effect of this adjustment decreases electric NOI by $913,000.

Starting on page 9 of Exhibit No. 11, Schedule 1, Adjustment (3.06) – **Pro Forma Capital Additions 2016 EOP,**

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[16] *Id.*

reflects additional 2016 capital additions[17] together with the associated AD and ADFIT on a December 31, 2016 EOP basis. This adjustment also includes associated depreciation expense for these 2016 additions, as well as, incremental annualized depreciation expense on plant-in service at December 31, 2015. In addition, the plant-in-service at December 31, 2015 end-of-period was adjusted to a December 31, 2016 EOP basis. Ms. Schuh describes this adjustment in detail within her testimony. The net effect of this adjustment increases Idaho electric rate base $46,343,000 and decreases NOI $2,338,000.

Adjustment (3.07) - **Pro Forma Capital Additions 2017 AMA**, reflects all Idaho 2017 capital additions together with the associated AD and ADFIT on a 2017 AMA basis. This adjustment includes associated depreciation expense for the 2017 additions. In addition, the plant-in-service at December 31, 2016 was adjusted to a 2017 AMA basis. Ms. Schuh also describes this adjustment in detail within her testimony. The net effect of this adjustment increases Idaho electric rate base $656,000 and decreases NOI $920,000.

[17] For each of the periods through December 2016 and 2017, distribution-related capital expenditures associated with connecting new customers to the Company's system was excluded. An increase in revenues from growth in the number of customers from the historical test year to the 2017 rate year is excluded, therefore, the growth in plant investment associated with customer growth was also excluded.

Final Summary

Q. How much additional net operating income would be required for the State of Idaho electric operations to allow the Company an opportunity to earn its proposed 7.78% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $9,456,000 for 2017, as shown on line 5, page 2 of Exhibit No. 11, Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $15,433,000 for 2017, or an increase of 6.34%.

VI. ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last electric general rate case, Case No. AVU-E-15-05?

A. No. For ratemaking purposes, the Company allocates revenues, expenses and rate base between electric and natural gas services and between Idaho, Washington and Oregon jurisdictions where electric and/or natural gas service is provided. The updated allocation factors used in this case have been provided with my workpapers.

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

A. Yes, it does.