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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-15-05
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-15-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	ELIZABETH M. ANDREWS
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

CONTENTS

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 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. 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 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 two-year rate plan and the need for the proposed increase in rates for both 2016 and 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.

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

A. Yes. I am sponsoring Exhibit No. 12, Schedule 1 (Electric) and Schedule 2 (Natural Gas), which were prepared under my direction. These exhibits consist of worksheets, which show actual twelve months ended December 31, 2014 operating results, pro forma, and proposed electric and natural gas operating results and rate base for the State of Idaho for rate years 2016 and 2017. 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 2016 and 2017.

II. COMBINED REVENUE REQUIREMENT SUMMARY – TWO-YEAR RATE PLAN: 2016 and 2017

Q. Please describe the Company's two-year rate plan proposed for the 2016 and 2017 rate years.

A. The Company is proposing a two-year rate plan for calendar years 2016 and 2017, with proposed increases effective January 1 of each year. The company is proposing a two-year rate plan, to once again, avoid annual rate cases in its Idaho jurisdiction[2], providing benefits to all stakeholders. A two-year rate plan, with increases in 2016 and 2017, would provide benefits to its customers by providing rate certainty over this two-year period; to Avista by providing a two-year window to manage its business in order to achieve a fair rate of return within known price changes; and relief to all stakeholders – customers, the

[2] Avista's last general rate case filing was in 2012 (Case Nos. AVU-E-12-08 and AVU-G-12-07) in which a two-year rate plan was approved for 2013-2014. The Commission later approved a proposal by the parties to extend the rate plan, with no base rate increase, until January 1, 2016 in Case Nos. AVU-E-14-05 and AVU-G-14-01.

Commission and its Staff, intervenors, and the Company, from the administrative burdens and costs of litigation of annual general rate cases.

Q. Please provide a summary of the 2016 and 2017 two-year rate plan results included in the Company's Idaho electric and natural gas operating pro forma studies.

A. After taking into account all standard Commission Basis adjustments, as well as additional pro forma and normalizing adjustments, the pro forma electric and natural gas rates of return ("ROR") for the Company's Idaho jurisdictional operations are 6.53% and 6.07%, respectively for rate year 2016. After taking into account additional incremental pro forma adjustments for the 2017 rate year, the pro forma electric and natural gas ROR are 5.46% and 5.33%, respectively, for rate year 2017. These return levels are well below the Company's requested rate of return of 7.62% for both the 2016 and 2017 rate years.

Table No. 1 below provides a summary of the 2016 and 2017 Rates of Return per the pro forma studies versus that proposed by the Company.

Table No. 1

Two-Year Rate plan Rates of Return			
Service	2016 Pro Forma	2017 Pro Forma	Proposed
ID Electric	6.53%	5.46%	7.62%
ID Natural Gas	6.07%	5.33%	7.62%

The incremental revenue requirement necessary to provide the Company an opportunity to earn its requested ROR in rate year 2016 is $13,230,000 for its electric operations, and $3,205,000 for its natural gas operations. The overall 2016 base electric increase associated with this request is 5.40%. The 2016 base natural gas increase is 8.84% (or 4.48% on a billed basis).

The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR in rate year 2017 is $13,713,000 for its electric operations and $1,665,000 for its natural gas operations. The overall 2017 incremental base electric increase associated with this request is 5.31%. The incremental 2017 base natural gas increase is 4.22% (or 2.19% on a billed basis).

Table No. 2 below provides a summary of the 2016 and 2017 requested revenue requirement and percentage increases.

Table No. 2

Two-Year Rate Plan
Revenue Requirement and Percentage Increases

Service	2016		2017	
	Revenue	Base %	Revenue	Base %
ID Electric	$ 13,230	5.40%	$ 13,713	5.31%
ID Natural Gas	$ 3,205	8.84%	$ 1,665	4.22%
Natural gas % increase on a billed basis:		*4.48%*		*2.19%*

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

A. The Company's last authorized rate of return for its Idaho operations was 7.91%, effective October 1, 2013 for both our electric and natural gas systems.

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

A. The primary factor driving the Company's electric and natural gas revenue requirements in 2016 and 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 (based on 2013 levels). As discussed further below, in 2016 these increased costs for electric operations are significantly offset by a reduction in net power supply and transmission expenditures. For 2017 net power supply expenses contribute significantly to the incremental revenue requirement requested above that proposed for 2016.

Other changes impacting the Company's revenue requirement requests relate to slight net 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.

Q. What are the major components of the increased net plant investment included in the Company's 2016 and 2017 electric and natural gas results?

A. Looking at the changes to "gross" plant in service for 2016, Idaho "gross" plant increases by approximately $162.3 million for electric, and approximately $35.6 million for natural gas, as compared to what was approved in the last general rate case (based on 2013 levels). For 2017, "gross" plant increases by approximately $55.4 million for electric, and approximately $9.4 million for natural gas, as compared to 2016.

In order to meet the energy and reliability needs of our customers, $74.5 million for 2016 and $29.9 million for 2017, 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. In 2016, electric distribution "gross" plant increases $56.2 million above that approved in the last general rate case, with an additional increase for 2017 of $21.4 million. The electric portion of general and intangible "gross" plant for 2016 and 2017 increases $31.6 million and $4.1 million, respectively.

Related to natural gas, in 2016 and 2017, $27.9 million and $8.3 million, respectively, of the "gross" plant increase is due to the Company's investment in natural gas distribution plant, while general “gross” plant for 2016 and 2017 increases $7.7 million and $1.1 million, respectively.

The specific 2015 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 and distribution assets and Mr. Kensok regarding the costs associated with Avista’s Information Service/Information Technology (IS/IT) projects. In addition to discussing the actual restating and pro forma adjustments regarding net plant investment, Company witness Ms. Schuh also describes all remaining 2015 through 2017 plant additions not described by Mr. Kinney, Mr. Cox or Mr. Kensok.

Q. Ms. Schuh explains the restating pro forma capital adjustments included in this case. Could you please briefly describe the conclusions drawn by Ms. Schuh regarding the increased capital investment?

A. Yes. As described in Ms. Schuh’s testimony, the Company is making substantial new investment in its electric and natural gas 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 and incur other costs related to the 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. Could you please provide additional details related to the changes in electric production and transmission expense?

A. Yes. As discussed in Company witness Mr. Johnson's testimony, the level of Idaho's share of power supply expense for 2016 has decreased by approximately $5.5 million ($15.7 million on a system basis) from the level currently included in base rates. However, for 2017, the proposed level of power supply expense is $8.7 million (ID share) higher than that proposed for 2016. Over half of this increase in 2017 is related to the expiration of a capacity sales agreement with Portland General Electric on December 31, 2016, resulting in reduced Idaho electric revenues of approximately $5.1 million ($14.5 million system).

Transmission net expense in 2016 is not materially different to that in current base rates, however, offsetting the increased power supply expense in 2017, transmission revenues are expected to increase by $776,000 ID share ($2,200,000 system) related to a Palouse Wind service contract, as explained by Mr. Cox.

Q. Could you please identify the main components of the distribution, O&M and A&G expense changes included in the Company's filing?

A. Yes. Certain expense items have increased since the 2013 rate year used in the last rate case. Employee benefits such as wages, pension and post-retirement medical expenses have increased. Also, as discussed by Mr. Kensok, additional costs associated with IS/IT expenses required to support a range of new and updated applications and systems for cyber security, the operation of the new Customer Information and Work and Asset Management Systems (Project Compass), the Asset Facilities Management application, etc., have increased from that in current base rates.

To recognize these cost changes, the Company has included a number of 2016 and 2017 pro forma adjustments to capture the net increases the Company will experience from the 2014 test year.

III. DERIVATION OF TWO-YEAR RATE PLAN REVENUE REQUIREMENT

Test Period for Ratemaking Purposes

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

A. The test period being used by the Company is the twelve-month period ending December 31, 2014, presented on a 2016 and 2017 pro forma basis. Currently authorized rates, effective October 1, 2013, were based upon the twelve-months ending December 31, 2012 test year utilized in cases AVU-E-12-08 and AVU-G-12-07, adjusted on a pro forma basis.

Revenue Requirement – 2016 and 2017

Q. Would you please explain what is shown in Exhibit No. 12, Schedules 1 and 2?

A. Yes. Exhibit No. 12, Schedules 1 and 2, show actual and pro forma (2016 and 2017) electric and natural gas operating results and rate base for the test period for the State of Idaho.

Column (b) of page 1 of Exhibit No. 12, Schedules 1 and 2, show December 31, 2014 actual operating results and components of the average-of-monthly-average (AMA) rate base as recorded[3]; column (c) is the total of all adjustments to net operating income and rate base to reflect 2016 results; and column (d) is the 2016 pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn a 7.62% rate of return for 2016. Column (f) reflects 2016 pro forma operating results with the requested increase of $13,230,000 for electric and $3,205,000 for natural gas.

Page 2 of Exhibit No. 12, Schedules 1 and 2, show similar columns starting with 2016 pro forma results (equal to column (d) on page 1 of Exhibit No. 12, Schedules 1 and 2), reflecting operating results and components of the average-of-monthly-average rate base at December 31, 2016, in column (b). Column (c), of page 2, 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) and (f) shows the revenue increases required in 2016 and 2017 to allow the Company to earn a 7.62% rate of return for 2017. Column (g) reflects 2017 pro forma operating results with the requested increases of $13,713,000 for electric and $1,665,000 for natural gas, above that requested in 2016.

[3] Actual plant rate base (cost, accumulated depreciation and associated DFIT) uses the 2014 AMA balances. Plant rate base is adjusted to a 2016 and 2017 AMA basis with restating and pro forma adjustments.

Q. Would you please explain page 3 of Exhibit No. 12, Schedules 1 and 2?

A. Yes. Page 3 of Exhibit No. 12, Schedule 1, shows the 2016 and 2017 revenue requirement calculations for electric of $13,230,000 and $13,713,000, respectively. Page 3 of Exhibit No. 12, Schedule 2, shows the 2016 and 2017 revenue requirement calculations for natural gas of $3,205,000,000 and $1,665,000, respectively. Each calculation is at the requested 7.62% rate of return.

Q. What does page 4 of Exhibit No. 12, Schedules 1 and 2 show?

A. Page 4 shows the proposed Cost of Capital and Capital Structure utilized by the Company in this case, and the weighted average cost of capital of 7.62%. 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 5 of Exhibit No. 12, Schedules 1 and 2?

A. Yes. Page 5 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 6 through 11 for electric (Schedule 1), and pages 6 through 10 for natural gas (Schedule 2), of your Exhibit No. 12, please explain what those pages show?

A. Yes. Page 6 begins with actual operating results and rate base for the test period in column (1.00). Individual normalizing and restating adjustments that are standard components of Commission Basis reporting or general rate case filings begin in column (1.01).

For electric, Exhibit No. 12, Schedule 1, individual pro forma adjustments for 2016 begin in column (3.01) on page 9 and go through column (3.14) page 10, with the "2016 FINAL TOTAL" column on page 10 representing the total pro forma operating results and net rate base for the 2016 pro forma period. Page 11 of Exhibit No. 12, Schedule 1, includes all 2017 pro forma adjustment columns (17.01) through (17.05), with the "2017 FINAL TOTAL" and "INCREMENTAL 2017I FINAL TOTAL" columns, representing the total pro forma operating results and net rate base for the 2017 pro forma period, and the incremental balances above the 2016 pro forma rate year.

For natural gas, at Exhibit No. 12, Schedule 2, individual pro forma adjustments for 2016 begin in column

(3.01) on page 8 and go through column (3.11) page 9, with to the “2016 FINAL TOTAL” column on page 9 representing the total pro forma operating results and net rate base for the 2016 pro forma period. Page 10 of Exhibit No. 12, Schedule 2, includes all 2017 pro forma adjustment columns (17.01) through (17.04), with the “2017 FINAL TOTAL” and “INCREMENTAL 2017I FINAL TOTAL” columns, representing the total pro forma operating results and net rate base for the 2017 pro forma period, and the incremental balances above the 2016 pro forma rate year.

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 adjustments are consistent with current regulatory principles and the manner in which they have been addressed in recent cases (i.e., AVU-E-12-08 and AVU-G-12-07), unless otherwise noted.[4] 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

[4] In Restating adjustments (1.03) Working Capital, (2.06) SIT/SITC expense and (2.09) Restate Incentives, the Company has proposed a different methodology to adjust the actual Idaho electric and natural gas results of operations amounts as recorded for 2014, as described below.

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:

Electric Adjustment (1.01) and Natural Gas Adjustment (1.01) - **Deferred FIT Rate Base**, adjusts the electric and natural gas Accumulated Deferred Federal Income Tax (ADFIT) balances. 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 (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated Cost Recovery, or MACRS) and bond refinancing premiums.

The effect of these adjustments on Idaho rate base is a reduction of $5,200,000 electric, and an increase of

$2,477,000 natural gas[5]. 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[6] is a reduction of $49,000 electric and an increase of $23,000 natural gas.

Electric Adjustment (1.02) and Natural Gas Adjustment (1.02) - **Deferred Debits and Credits**, 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 decreases Idaho electric rate base by $545,000 and increases NOI by 213,000. No adjustment is necessary for natural gas rate base or net income.

Adjustments included in the Deferred Debits and Credits consolidated adjustment are those necessary to reflect restatements from 2014 actual results (included in column 1.00 “Per Results of Operations”), based on prior Commission orders as explained below.

[5] The changes in electric and natural gas rate base are primarily due to two items. First, an increase in ADFIT as a result of Avista recording in the test period the estimated tax deduction the Company intends to file with its 2014 federal tax return. Avista plans to make a “Change of Accounting” filing to implement certain IRS Tangible Property Regulations associated with revised rules on property capitalization versus repair requirements. The study to implement this tax accounting change, commonly referred to as a “Repairs Study”, will be finalized during 2015. The 2014 recorded estimate was based on the best available information and currently is not expected to change materially. Second, an increase in electric ADFIT, and a reduction to natural gas ADFIT, was recorded to reflect corrections of ADFIT balances within the general ledger.

[6] 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.

- **Colstrip 3 AFUDC Elimination (electric)** 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. These amounts are a component of actual results of operations.

- **Colstrip Common AFUDC (electric)** 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 (electric)** reflects 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.

- **<u>Restating CDA Settlement Deferral (electric)</u>** 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 2016 AMA basis, and records the annual amortization expense based on a ten-year amortization, as approved in Case No. AVU-E-10-01.

- **<u>Restating Spokane River Deferral (electric)</u>** adjusts the net asset and DFIT balances related to the Spokane River deferred relicensing costs as recorded to a 2016 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01.

- **<u>Restating Spokane River PM&E Deferral (electric)</u>** adjusts the net asset and DFIT balances related to the Spokane River deferred PM&E costs as recorded to a 2016 AMA basis, and records the annual amortization expense based on a ten-year amortization as approved in Case No. AVU-E-10-01.

- **<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 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 eight-year amortization of the deferral expires September 2016, and has been properly reflected in this filing. This adjustment also includes the adjustment to annual lease payment expense for the required annual inflation adjustment.

- **<u>Weatherization and DSM Investment (electric)</u>** includes in rate base the Sandpoint weatherization grant balance (FERC account 124.350). Beginning in July

1994 accumulation of AFUCE[7] 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.

- **Customer Advances (electric and natural gas)** 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 (electric)** removes the amortization expense included in the 2014 test period. In May 2008, Avista purchased the Reardan Wind Project Site from 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.

Electric Adjustment (1.03) and Natural Gas Adjustment (1.03) - **Restate Capital 2014 EOP**, restates the capital investment and expenses associated with adjusting the 2014 average-of-monthly-average (AMA) plant related balances to December 31, 2014 end-of-period (EOP) balances. The effect on Idaho rate base is an increase of $226,000 to electric, and a reduction of $2,674,000 to natural gas rate base. The effect on Idaho net operating income (NOI) is an increase of

[7] Allowance for funds used to conserve energy.

$2,000 electric, and a reduction of $25,000 natural gas related to the federal income tax effect of debt interest.

Electric Adjustment (1.04) and Natural Gas 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 2014 AMA test period amount calculated using the Investor Supplied Working Capital (ISWC) method. Working capital included in the Results of Operations is only Idaho's portion of the 2014 average-monthly-average balances of FERC accounts 151 (Fuel Stock Inventory) and 154 (Plant Materials & Supplies).

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. Working capital represents investor supplied funds that are properly included in the Company's rate base for ratemaking purposes.

While there are various methods used to determine a Company's working capital, the Company has calculated its working capital in this proceeding using the Investor Supplied Working Capital method. By including only Fuel Stock Inventory and Plant Materials & Supplies, working capital is understated. The Company believes the ISWC is a reasonable approach to computing working capital, representing expended funds to provide reliable service to its customers.

Q. Does the need for working capital also include long-term timing differences?

A. Yes, specifically, FERC account 228.3 (Pension and other post-retirement liabilities), and FERC account 182.3 (associated pension related regulatory assets). In order to recover the financing costs associated with the Company’s net prepaid pension asset, offset by its accrued post-retirement liability and associated ADFIT, the Company believes it is appropriate to include these balances in its ISWC.

The Company’s net prepaid pension asset/accrued post-retirement liability represents the difference between the amounts contributed to its pension and post-retirement benefit plans, and amounts recorded to expense for those same plans. These differences between cumulative expense and contributions have arisen as a result of funding requirements and funding policies. For example, the federal Pension Protection Act of 2006, as amended, has required the Company to contribute significant amounts to its pension plan since enacted.

For ratemaking purposes, the Company recovers pension and post-retirement costs based on the amount recorded to expense. Investor capital is impacted by any difference between the amounts contributed to the plans and the amounts included in rates as expense, therefore investors have borne the cost of financing the incremental contributions.

As of December 31, 2014, these cumulative contributions in excess of cumulative expenses, have resulted in a net prepaid pension asset/accrued post-retirement liability (offset by associated AFDIT) of $49.2 million on an AMA basis. Idaho's allocated share totals $10.7 million for electric, and $2.7 million for natural gas.

Q. Have the net prepaid pension contributions been included in working capital in other jurisdictions?

A. Yes. In the Company's Washington jurisdiction, the Washington Utilities and Transportation Commission (WUTC) approved this approach for PacifiCorp, in WUTC v. PacifiCorp, Docket UE-130043. WUTC Staff witness Mr. Zawislak, in Exhibit No. ___(TWZ-1), at page 3, lines 20-22, supported the inclusion of post-retirement benefits in PacifiCorp's working capital balance, stating:

> Mr. Stuver's treatment of [pension and] post-retirement benefits achieves a proper balance of ratepayer interests and allows investors to earn a return on the net unamortized funds they have contributed to Company employees' post-retirement benefits.

The WUTC Commissioners approved this treatment at Order 05, page 93, paragraph 240, stating:

> As Mr. Zawislak testifies, PacifiCorp's ISWC adjustment is a refinement to the methodology that corrects the calculation of ISWC with respect to pensions and other post-retirement benefit liabilities including the associated regulatory assets and derivative assets and liabilities. We determine that PacifiCorp's adjustment to working capital relying on the ISWC approach is supported by the record and should be allowed.

In 2014, Docket Nos. UE-140188 and UE-140189, UTC Staff witness Ms. Erdahl, in Exhibit No. ____(BAE-1T), page 4, lines 3-10, recommended approval of Avista's requested treatment of pensions and other post-retirement benefits and liabilities, including the associated regulatory assets and related tax impacts in its ISWC. Specifically at page 8, lines 17-22 she states:

> Staff evaluated Avista's ISWC calculation for both electric and natural gas service. Staff reviewed the underlying balance sheet accounts and allocation methodology and determined the Company's calculation is correct as of the update Avista provided on June 26, 2014, in response to Staff Data Request 115. Accordingly, there are no substantive differences between Staff and Company on this issue.[8]

In Avista's Oregon service territory, the Public Utility Commission of Oregon has an on-going investigation (Docket UM 1633) into the treatment of pension costs in

[8] Avista's revenue requirement approved in its most recent Washington general rate case (GRC) proceedings were approved through an all party settlement with an agreed upon amount. No specific approval from the Commission was noted in the order relating to working capital; however, no party to the proceeding opposed the Company's ISWC calculated amounts. This same approach has been included in the Company's current GRC filed with the WUTC in Docket Nos. UE-150204 and UG-150205.

utility rates, including the opportunity to rate base net prepaid pension asset balances (offset by ADFIT). A decision in this Docket is expected in July 2015.

Q. What is the impact of the electric and natural gas working capital adjustments on Idaho's pro forma rate base and net income?

A. The effect of the Working Capital adjustments (1.04) on Idaho rate base from that recorded in the 2014 test period is an overall increase of $14,732,000 electric and $2,218,000 natural gas. The effect on Idaho net operating income (NOI) is an increase of $138,000 electric and $21,000 natural gas, related to the federal income tax effect of debt interest.

Q. Please continue with your discussion of the restating adjustments included in Exhibit No. 12, Schedules 1 and 2.

A. Electric Adjustment (2.01) and Natural Gas 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 $6,000 and natural gas NOI by $1,000.

Electric Adjustment (2.02) and Natural Gas Adjustment (2.02) - **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment increases electric NOI by $61,000 and natural gas NOI by $206,000.

Electric Adjustment (2.03) and Natural Gas Adjustment (2.03) - **Regulatory Expense**, restates recorded test period regulatory expense to reflect the IPUC assessment rates applied to expected revenues for the test period and the actual levels of FERC fees paid during the test period. The effect of this adjustment increases electric NOI by $35,000, while natural gas NOI decreases by $5,000.

Electric Adjustment (2.04) and Natural Gas 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 $35,000 and decreases natural gas NOI by $77,000.

Electric Adjustment (2.05) **FIT/DFIT/ITC/PTC Expense** and Natural Gas Adjustment (2.05) - **FIT/DFIT 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, for electric this adjustment records the appropriate level of production tax credits and income tax credits on qualified electric generation.

For the electric adjustment, the net tax credit adjustment decreases Idaho electric NOI by $6,000. For the natural gas adjustment, no adjustment is required.

Electric Adjustment (2.06) and Natural Gas Adjustment (2.06) - **SIT/SITC Expense**, adjusts Idaho State Income Tax (SIT) expense and Idaho State Investment Tax Credits (SITC) applicable to Idaho electric and natural gas operations as recorded. The effect on Idaho net operating income (NOI) is a decrease of $1,246,000 for electric and a decrease of $442,000 for natural gas. In this filing, the Company made two changes to its method to determine the rate year level of SIT expense from previous general rate cases in Idaho, which are described below. The Company used the same revised method to determine the SIT rate that is used in the derivation of the net operating income to gross revenue conversion factor as shown on page 4 of Exhibit No. 12, Schedules 1 and 2.

Q. Please describe the two changes made to determine the rate year level of SIT expense.

A. The Company has historically used the apportionment method to determine SIT expense and continues to use the apportionment method in this filing. This method determines Idaho's taxable income using an apportionment factor for Idaho that is applied to the total Company taxable income. Idaho's state tax rate is then applied to the computed Idaho's taxable income to derive the state income tax expense. In past general rate cases, the Company has used the system apportionment tax rate and has applied it to Idaho stand-alone taxable net income, which incorrectly computes SIT expense. In this filing, the system apportionment tax rate was converted to an Idaho tax rate, so when it is applied to Idaho stand-alone taxable net income, the SIT expense is properly computed.

The second change made by the Company relates to the use of Idaho investment tax credits. The Company has historically used the flow-through method to pass through earned tax credits to rate payers. Using the flow-through method, all Idaho investment tax credits available in a year were used to offset 50% of the SIT owed to Idaho, so customers immediately had the benefit of lower state income taxes.

Through discussions with Avista's external auditor's (Deloitte Touche) it was determined that this method should no longer be used by Avista. Avista is required to normalize its federal investment tax credits pursuant to Internal Revenue Code section 46(f)(2). In addition, the Idaho tax code refers to the Federal standards for ITC normalization. Therefore, it was determined that the

Company must also normalize its Idaho investment tax credits. Beginning with the effective date of new customer rates from this case, the Company will defer its SITCs and will amortize (i.e. return to customers) the credits over the life of the assets.

Q. What SIT rate was used in the net operating income to gross revenue conversion factor?

A. The Company used 4.9% for the SIT rate in this case, before adjusting for other revenue-sensitive expenses. The calculation of this rate is described below.

Idaho’s taxable income is determined by applying the apportionment factor of 19.73% to system taxable income. The tax is then computed by applying the Idaho tax rate, currently 7.40%, to the calculated Idaho taxable income. This amount is the tax that is paid to the State of Idaho. Avista records approximately 82% of total Idaho tax to the Idaho electric operations and 18% to the Idaho natural gas operations.

The “apportionment tax rate” for computing Idaho state income taxes is shown below in Table No. 3.

Table No. 3:

Calculation of Avista's Apportionment Tax Rate				
Idaho's Apportionment Rate	X	Idaho's Tax Rate	=	Idaho's Apportionment Tax Rate (Applied to System Taxable Income)
19.73%	X	7.40%	=	1.460%

By using the three components of the actual tax calculation for the Idaho operations, an Idaho apportionment tax rate is 1.46%, which is then applied to system taxable income. This rate can only be used if it is applied to Avista Utilities' total system revenues, system expenses and system taxable income. When Avista prepares a general rate case revenue requirement, the starting point is the actual Results of Operations for its Idaho electric and natural gas operations. Use of this rate in a general rate case, which is calculated based on Avista's total utility system in Idaho, Washington and Oregon, would understate SIT. In this filing, the Company used an Idaho apportionment tax rate of 4.9%, which produces the appropriate level of expense when applying it to Idaho's taxable income.

The 4.9% tax rate was determined by "grossing up" the 1.46% apportionment rate for system taxable net income by Idaho's (electric and natural gas) share of system revenues, totaling approximately 29.8%. (Idaho apportionment tax rate = 1.46% / 29.8% = 4.9%)

Electric Adjustment (2.07) and Natural Gas 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 Nos. AVU-E-12-08 and AVU-G-12-07 effective October 1, 2013), 2) weather normalization, and 3) an unbilled revenue calculation. For the electric adjustment, 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. For the natural gas adjustment, all revenues and expenses associated with the Purchased Gas Cost Adjustment Schedule 150 have been removed from the Company's filing. In addition, revenues associated with the temporary Gas Rate Adjustment Schedule 155, Schedule 191 Tariff Rider, and Schedule 197 Refund of Deferred Gas Costs are excluded from pro forma revenues, and the related amortization expenses are eliminated as well. Company witnesses Ms. Knox (electric) and Mr. Miller (natural gas) sponsors these two adjustments.

The effect of this adjustment increases electric NOI $4,056,000 and increases natural gas NOI $838,000.

Electric Adjustment (2.08) and Natural Gas 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[9]. The net effect of this adjustment decreases electric NOI by $47,000 and decreases natural gas NOI by $13,000.

Electric Adjustment (2.09) and Natural Gas Adjustment (2.09) - **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 2015 incentives to be accrued for officers (paid Q-1 of 2016), based on O&M targets.[10] This amount was then multiplied by the six-year average of actual percentage payouts for the years 2009-2014

[9] 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 $700,000. In order to reflect the appropriate labor for 2014, this adjustment recognizes this increase in expense.

[10] Officer STIP based on earnings per share targets are excluded from this calculation. Long-term incentives based on financial metrics (performance shares) and those short-term incentives based on earnings per share are currently borne by shareholders.

(or 40.23%). For non-officer incentives, this is calculated by using the 2016 level of labor expense (determined in adjustment (3.03) electric and (3.02) natural gas - Pro Forma Labor Non-Exec) multiplied by the payout incentive opportunity per the Company’s current incentive plan (or 12% overall) to determine the incentive payout opportunity, multiplied by the six-year average of actual percentage payouts for the years 2009-2014 (or 102.16%). The net effect of this adjustment increases Idaho NOI by $315,000 electric and $80,000 natural gas.

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 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/variable performance based via 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 likely to produce long term customer benefits. This tension in plan design helps incent and focus all employees on the stated goals of the Company. In order to achieve this pay-at-risk compensation, employees have to keep focused on 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. The pay-at-risk component of compensation is not designed to pay out the full incentive opportunity every year, nor is it designed to have no payout for an extended period of time. Pay-at-risk plans are designed to help focus employees on stated goals that benefit the Company and its 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 ratepayers, it is appropriate to include the customer focused STIP incentives in general rates. The 2014 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. Therefore, the appropriate portion of incentives related to non-utility is reflected on the Company's general ledger for both executive and non-executive STIPs.

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.

[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.

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 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 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].

Q. What amount of the LTIP costs is included in retail rates in this filing?

A. The LTIP expense included in retail rates in this filing are related to Restricted Stock Units totaling $1.0 million on a system basis in 2014. Idaho’s share of this expense amount is approximately $229,000 electric and $58,000 natural gas.

Q. Please continue with explaining the remaining restating adjustments in Exhibit 12, Schedules 1 and 2.

A. The next adjustment is Electric Adjustment (2.10) - **Idaho PCA**, which removes the effects of the financial accounting for the Power Cost 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

[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.

Supply, respectively. The effect of this adjustment decreases Idaho NOI by $1,033,000.

Electric 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 $8,000.

Electric Adjustment (2.12) - **Restating CS2 Levelized Adjustment**, removes the final amortization expense recorded in 2014 related to the deferred return associated with Coyote Springs 2 (CS2). In the Company's electric general rate case, Case No. AVU-E-04-1, Order No. 29602, dated October 8, 2004, the Commission approved the deferral of return on CS2 investment in early years for recovery in later years in order to levelize the revenue requirement on CS2 plant investment for the first ten years of operation of the plant. The ten-year period ran from September 1, 2004 through August 31, 2014. This adjustment removes the test period amount. This adjustment increases NOI by $253,000.

(2.13) – **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 non-fuel O&M costs associated with the Company's Colstrip and CS2 thermal generating plants. The deferral amount is the difference between actual costs in excess of authorized "Base O&M" costs for each respective year, included in base rates for the years 2011 – 2014 and estimated for 2015.

For calendar years 2013 through 2015, the last authorized "Base O&M" expense level (established in 2013 in AVU-E-12-08) was $14.4 million, and will remain this amount going forward unless adjusted. Each prior year deferred costs are amortized over a three-year period.

In addition to the three-year amortization, the Company is proposing to adjust the "Base O&M" cost 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 reduces the amount of the deferral that will be required in 2016 and forward, where actual O&M expense is expected to be $24.3 million in 2016[13], and range from $18.8 million to $22.0 million in years 2017-2019. The effect of this proposed change increases Idaho electric expense by $2.07

[13] In 2016 CS2 will require its 72,000 run-hour hot gas path maintenance, which occurs on an approximate four-year cycle, the last occurring in 2012.

million.

One-third of each amount deferred for calendar years 2013 through 2015, plus the additional proposed expense for the 2016 rate year, increases Idaho electric expense by approximately $2.6 million, and decreases NOI by $1,705,000.

Electric Adjustment (2.14) and Natural Gas Adjustment (2.10) - **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 decreases electric NOI by $437,000 and natural gas NOI by $75,000.

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. 2016 AND 2017 PRO FORMA ADJUSTMENTS

Q. Please explain the significance of the adjustments beginning at page 9 for Schedule 1 (electric) and page 8 for Schedule 2 (natural gas) of Exhibit No. 12.

A. The adjustments on pages 9 and 10 of Exhibit No. 12, Schedule 1, and pages 8 and 9 of Exhibit No. 12, Schedule 2 are pro forma adjustments that recognize the jurisdictional impacts of items that will impact the 2016 pro forma operating period.

Included on page 11, Schedule 1 and page 10, Schedule 2 of Exhibit No. 12, are additional pro forma adjustments that recognize the jurisdictional impacts of items that will impact the 2017 pro forma operating period.

These pro forma adjustments in 2016 and 2017 encompass revenue and expense items as well as additional capital projects, bringing the operating results and rate base to the final pro forma levels for the 2016 and 2017 rate years.

In the discussion that follows, an explanation of each 2016 and 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. As described below and provided in accompanying workpapers, these adjustments are consistent with current regulatory principles and the treatment reflected in the last rate case, with a few proposed changes by the Company discussed below.

2016 Rate Year – Summary of Adjustments

Q. Please explain each of the 2016 Pro Forma adjustments included in Exhibit No. 12, starting on page 9 of Schedule 1 and page 8 of Schedule 2.

A. The first adjustment, starting on Exhibit No. 12, page 9, of Schedule 1 is Electric 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, 2016 through December 31, 2016, 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 increases electric NOI by $3,302,000.

Electric 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, 2016 through December 31, 2016. The net effect of this adjustment decreases electric NOI by $19,000.

Electric Adjustment (3.03) and Natural Gas Adjustment (3.01) - **Pro Forma Labor Non-Exec**, reflects changes to 2014 test period union and non-union wages and salaries, excluding executive salaries.

For non-union employees, base year wages and salaries are restated to annualize the March 2014 overall actual increase of 3.0%, the March 2015 overall increase of 3.0%, and 10 months of the planned March 2016 increase of 3.0%[14].

For union employees, adjustments were made to the 2014 base year wages and salaries in accordance with contract terms. The current contract between the Company and Local Union No. 77 is in effect from March 26, 2014 through March 26, 2016. The terms of the contract call for 3% wage and salary increases effective March 27th for 2014 and 2015. Accordingly, base year wages and salaries are restated to annualize the March 2014 increase, the March 2015 increase and approximately nine months of an expected 2016 increase. The net effect of this adjustment on Idaho’s NOI is a decrease of $1,132,000 electric and $293,000 natural gas.

Electric Adjustment (3.04) and Natural Gas Adjustment

[14] A minimum increase of 2.9% for 2016 was approved by the Compensation Committee of the Board of Directors at the May 2015 Quarterly Board meeting. The actual increase will be updated at or above this minimum based on market data provided in November 2015, with an effective date in March 2016.

(3.02) - **Pro Forma Labor Exec**, reflects the current 2015 executive officer salaries. However, the Company has included updated utility and non-utility allocation percentages planned for 2016. The net result of these changes increases the executive compensation expense approximately $151,000 electric and an increase of $30,000 for natural gas from that included in the Company's historical base year. No additional increases in executive labor for 2016 have been included in this filing.

The allocation of individual executive officer base salaries between utility and non-utility is based on an annual survey, which asks each officer to estimate the percent of their time they will spend on utility, AEL&P and non-utility operations. Allocation percentages are based on the informed judgment of each executive officer taking into consideration a number of factors including, but not limited to, current and past job responsibilities, anticipated changes due to projects specific to the upcoming year, anticipated responsibility and/or overall upcoming strategic initiatives and associated roles. The non-utility/utility labor is updated in the bi-weekly timekeeping system as we progress through the year based on actual time and changes to strategic initiatives or job responsibilities.

As discussed by Mr. Thies, during 2014 the Company sold its largest subsidiary (ECOVA), and acquired Alaska Energy and Resources Company (AERC) and its subsidiary Alaska Electric Light & Power (AEL&P). These activities took time during 2014 that will not be required during 2015 and 2016. Accordingly, executive officers have adjusted their non-utility allocation percentage to reflect these changes for 2015/2016 resulting in an overall decrease to approximately 11% from the 15% level in the last survey. Therefore, while the level of base salaries has remained at the 2015 level, changes due to updated utility/non-utility allocation factors to approximately 89% utility and 11% non-utility resulted in a decrease in Idaho electric NOI of $98,000 and an NOI decrease of $20,000 for natural gas.

Electric Adjustment (3.05) and Natural Gas Adjustment (3.03) - **Pro Forma Employee Benefits**, adjusts for changes in both the Company's pension and medical insurance expense and decreases electric NOI by $1,050,000 and decreases natural gas NOI by $282,000.

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

A. The Company's pension expense portion of the calculation above is determined in accordance with Accounting Standard Codification 715 (ASC-715), and has increased on a system basis from approximately $19.5 million for the actual base year costs for the twelve months ended

December 31, 2014, to $28.7 million for 2016[15]. The increase in pension expense included in this case (Idaho share of $1.2 million electric and $330,000 natural gas) is primarily due to updated mortality tables, the discount rate on pension liability and expected return on assets.

The pension cost included in this case is based on expected costs as of September 22, 2014 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 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 will replace 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 will provide a non-elective contribution as a percentage of each employee’s pay based on his or her

[15] In May 2015 the Company received and presented to the Compensation Committee of the Board revised 2016 Pension cost amounts totaling $31.4 million. These amounts were received after the revenue requirement calculations had been finalized. The Company will provide all updates associated with pension expense during the process of this proceeding.

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.

Q. Please describe the medical insurance and post-retirement expense portion of Electric Adjustment (3.05) and Natural Gas Adjustment (3.03), and Idaho's share of this expense.

A. The Company's medical insurance and post-retirement expense portion of these adjustments (Idaho's share of $472,000 electric and $127,000 natural gas) adjusts for the expected medical-related costs for 2016 above the 2014 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 $27.5 million for the 2014 base year to $31.0 million for 2016[16]. The increase in 2016 represents medical trend and utilization expectations, as well as accounting for Health Care Reform mandates.

[16] In May 2015 the Company received and presented to the Compensation Committee of the Board revised 2016 post-retirement and medical cost amounts totaling $31.7 million. These amounts were received after the revenue requirement calculations had been finalized. The Company will provide all updates associated with post-retirement and medical expense during the process of this proceeding.

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

A. In October 2013 the Company revised its health 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.

Q. Please continue with your discussion of the 2016 pro forma adjustments.

A. The next adjustment is Electric Adjustment (3.06) and Natural Gas Adjustment (3.04) - **Pro Forma Insurance**, which adjusts the 2014 test period insurance expense for general liability, directors and officers ("D&O") liability, and property insurance to 2016 expected levels.

Costs of system-wide insurance policies for 2016 have increased $410,000 or approximately 8% from the policies in 2014. Over half of this increase relates to the increase in general liability insurance, which is mainly due to primary insurance policy providers seeking increases due to adverse impacts over the last several years from increased claim history and due to suspension by insurance providers of the continuity credit provided in previous years. The net effect of this adjustment decreases NOI by $58,000 electric and $15,000 natural gas.

Electric Adjustment (3.07) and Natural Gas Adjustment (3.05) – **Pro Forma Property Tax**, restates the 2014 test period accrued levels of property taxes to the 2016 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, 2015, reflecting the 2016 level of expense the Company will experience during the 2016 rate period. The net effect of this adjustment decreases NOI by $795,000 electric and $322,000 natural gas.

Electric Adjustment (3.08) and Natural Gas Adjustment (3.06) – **Pro Forma Information Technology/Information Services Costs**, which includes the incremental costs associated with software development, application licenses, maintenance fees, and technical support for a range of information services programs. As discussed further by Mr. Kensok, 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 services. The effect of this adjustment decreases Idaho NOI by $380,000 electric and $96,000 natural gas.

Electric Adjustment (3.09) and Natural Gas Adjustment (3.07) – **Pro Forma Capital Additions 2015 EOP**, reflects additional 2015 capital additions[17] together with the associated AD and ADFIT at a December 31, 2015 EOP basis. This adjustment also includes associated depreciation expense for these 2015 additions. In addition, the plant-in-service at December 31, 2014 end-of-period was adjusted to a December 31, 2015 EOP basis. Ms. Schuh describes this adjustment in detail within her testimony. The effect of this adjustment increases Idaho rate base $77,712,000 electric and $11,716,000 natural gas. The effect of this adjustment on Idaho NOI is a decrease of $3,618,000 electric and $661,000 natural gas.

Electric Adjustment (3.10) and Natural Gas Adjustment (3.08) - **Pro Forma Capital Additions 2016 AMA**, reflects all 2016 capital additions together with the associated AD and ADFIT at a 2016 AMA basis. This adjustment includes associated depreciation expense for the 2016 additions. In addition, the plant-in-service at December 31, 2015 was

[17] For each of the periods December 2015, 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 2016 and 2017 rate years are excluded, therefore, the growth in plant investment associated with customer growth was also excluded.

adjusted to a 2016 AMA basis. Ms. Schuh also describes this adjustment in detail within her testimony. The net impact of this adjustment is a reduction in total rate base of $1,789,000 electric and $669,000 natural gas. The net effect of this adjustment on Idaho NOI is a decrease of $469,000 electric and $97,000 natural gas.

Electric Adjustment (3.11) and Natural Gas Adjustment (3.09) – **Pro Forma Operation & Maintenance (O&M) Offsets**, includes O&M offsets related to specific plant additions. As explained by Ms. Schuh, all of the 2015 and 2016 capital additions were reviewed for any net O&M offsets, both increases in expenses and savings that are expected in the 2016 rate period. Specific expenses and savings identified were included as an increase or reduction to O&M costs in the Pro Forma Studies, and discussed in Mr. Kinney, Mr. Cox, and Ms. Schuh's direct testimonies with the capital asset with which the net offset relates. The net effect of this adjustment decreases Idaho NOI by $12,000 electric and $2,000 natural gas.

Natural Gas Adjustment (3.10) - **Pro Forma Atmospheric Testing**, adjusts the test period expense for Atmospheric Corrosion Testing expense to include one-third of the expenses recorded in the 2014 test period. Over the last several years Atmospheric Testing has been completed on a three-year rotation between the Company's jurisdictions

(Idaho, Washington and Oregon) and was therefore, coded directly to each jurisdiction operations in the year in which the inspection occurred. In 2014, this inspection program was completed in Idaho and expensed in total to Idaho operations at a cost of $593,000. Therefore, the Company has included only one-third of these costs in order to recover this amount over a three-year period (2014-2016), reducing Idaho natural gas expense by $395,000.[18] The net effect of this adjustment increases natural gas NOI by $244,000.

Electric Adjustment (3.10) - **Pro Forma Lake Spokane Two-Year Amortization**, reflects the proposed two-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 sought, and 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, and a prudency review of these costs to occur in the

[18] Starting in 2016 in Washington, and 2017 in Idaho and Oregon, Atmospheric Testing will be transitioned from completing this testing every three years by state to an inspection cycle that is completed 1/3 by state, per year. See 2017 pro forma adjustments discussion below for further explanation.

next general rate case or future proceeding. Mr. Kinney discusses these costs in his direct testimony. The net effect of this adjustment decreases electric NOI by $147,000.

Electric Adjustment (3.13) - **Pro Forma Colstrip Settlement**, reflects the proposed two-year amortization of the deferred revenues received from insurance proceeds related to the Colstrip lawsuit settlement funds received in 2014. Consistent with expenses associated with the Colstrip lawsuit settlement payments made in 2008 previously deferred[19] and amortized over two-years[20] in Idaho's jurisdiction, the Company is proposing a two-year amortization of these refund amounts. The net effect of this adjustment increases electric NOI by $124,000.

Electric Adjustment (3.14) and Natural Gas Adjustment (3.11) - **Pro Forma Project Compass Deferral Amortization,** includes the amortization expense associated with a proposed two-year amortization of 80% of the deferred electric and natural gas revenue requirement amounts associated with the Company's Project Compass Customer Information System (Project Compass) for calendar year 2015.

In Case Nos. AVU-E-14-05 and AVU-G-14-01, the

[19] Deferral of lawsuit expenses were approved in Order No. 30638, Case No. AVU-E-08-03.

[20] A two-year amortization of the Colstrip Lawsuit expenses were approved in Case No. AVU-E-09-01.

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. The 80% figure was arrived at through negotiation for calendar year 2015 only, and was unrelated to any assessment or determination of the prudence of the Project. The deferral was due, in part, to the uncertainty of the timing of the in-service date for the project. Avista was to address the prudence of Project Compass in its next general rate case.

This project was moved into service on February 2, 2015. Mr. Kensok discusses Project Compass in detail within his testimony, and Ms. Schuh incorporates the capital additions related to this project within her adjustments.

The effect of this adjustment decreases Idaho NOI by $822,000 electric and $207,000 natural gas.

2017 Rate Year – Summary of Adjustments

Q. Please now explain each of the 2017 Pro Forma adjustments included in Exhibit No. 12, starting on page 10 of Schedule 1 and page 9 of Schedule 2.

A. Yes. But before I begin, it is important to note that the Company has only included the incremental expenses above 2016 level revenue and expenses for major cost categories, such as new plant investment, including depreciation and property taxes, expected increases in net power supply and transmission costs, labor costs, and atmospheric testing related to natural gas operations. The Company believes there will be additional increased expenses during the 2017 rate year not included here, and therefore the results of the 2017 pro forma incremental 2017 revenue requirement included in this filing is conservative.

Please also note, 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 2017 pro forma adjustments. A summary of each adjustment follows:

The first adjustment, starting on Exhibit No. 12, page 11, of Schedule 1 is Electric Adjustment (17.01) - **Pro Forma Power Supply**. This adjustment was made under the direction of Mr. Johnson and his testimony discusses the 2017 system level pro forma power supply revenues and expenses that are included in his adjustment. This adjustment includes Idaho’s share of the net pro forma power supply revenue and expenses to reflect the twelve-month period January 1, 2017 through December 31, 2017, using historical loads. The Pro Forma 2017 power supply revenues and expenses is compared to the Pro Forma 2016 power supply revenues and expenses to adjust for the incremental power supply expense in the 2017 rate year.[21] The net effect of this adjustment decreases electric NOI by $5,427,000.

Electric Adjustment (17.02) - **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 incremental revenues and expenses for the twelve-month period January 1, 2017 through December 31, 2017. The net effect of this adjustment increases electric NOI by $437,000.

Electric Adjustment (17.03) and Natural Gas Adjustment (17.01) - **Pro Forma Labor Non-Exec**, reflects incremental union and non-union wages and salaries from 2016 to 2017, excluding executive salaries.

For <u>non-union</u> employees, wages and salaries were adjusted to annualize the March 2016 estimated increase of 3.0%[22], and 10 months of the estimated March 2017 increase of 3.0%. For <u>union</u> employees, wages and salaries were adjusted to annualize the March 2016 estimated increase and

[21] As discussed by Mr. Johnson, the largest driver increasing net power supply expense from 2016 to 2017 is the expiration of the Portland General Electric capacity sale December 31, 2016, increasing Idaho's net power supply expense approximately $5.1 million ($14.5 million system).

[22] A minimum increase of 2.9% for 2016 was approved by the Compensation Committee of the Board of Directors at the May 2015 quarterly Board meeting. The actual increase will be updated at or above this minimum based on market data provided in November 2015, for an effective date in March 2016.

10 months of the estimated increase for March 2017. The incremental increase above the 2016 Pro Forma labor Non-Exec adjustment was included in 2017 to reflect 2017 rate year levels. The net effect of this adjustment on Idaho’s NOI is a decrease of $378,000 electric and $101,000 natural gas.

Electric Adjustment (17.04) and Natural Gas Adjustment (17.02) – **Pro Forma Property Tax**, reflects incremental property tax expense from 2016 to 2017 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 NOI by $571,000 electric and $161,000 natural gas.

Electric Adjustment (17.05) and Natural Gas Adjustment (17.03) - **Pro Forma Capital Additions 2017 AMA**, reflects all 2017 capital additions together with the associated AD and ADFIT at a 2017 AMA basis. This adjustment includes associated depreciation expense for the 2017 additions. In addition, the plant-in-service on a 2016 AMA basis is adjusted to a 2017 AMA basis. Ms. Schuh also describes this adjustment in detail within her testimony. The net impact of this adjustment is an increase in total rate base of $17,746,000 electric and $3,339,000 natural gas. The net effect of this adjustment on Idaho NOI is a decrease of $1,136,000 electric and $223,000 natural gas.

Natural Gas Adjustment (17.04) - **Pro Forma Atmospheric Testing**, adjusts the 2016 rate year expense for Atmospheric Testing to the expense level expected in the 2017 rate year.

As noted above in Pro Forma Atmospheric Testing adjustment (3.10), the 2016 Atmospheric Corrosion expense was included at one-third of the expenses recorded in the 2014 test period to recover costs over three years to match the every-three-year cycle in which this testing program was being completed in each state. Starting in 2016 in Washington, and 2017 in Idaho and Oregon, however, the Atmospheric Testing will be transitioned from completing this testing every three years by state to an inspection cycle that is completed one-third by state, per year.

Over the last several years, administering this program on an every-three-year cycle has resulted in two primary program challenges: 1) inadequate availability of state resources to respond to inspection follow-up actions due to the volume spike of work once every three years and 2) varying O&M expenditure requirements related to the inspection results in each state during this three year period. Moving the inspection cycle to one-third by state by year will levelize program spending and resources required to mitigate the inspection anomalies noted above.

(For more information regarding the Atmospheric Testing program see my filed workpapers.)

The net effect of this adjustment decreases natural gas NOI by $284,000.

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 7.62% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $8,131,000 for 2016 and $8,428,000 for 2017, as shown on line 5, page 3 of Exhibit No. 12, Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $13,230,000 for 2016, or an increase of 4.58%, and $13,713,000 for 2017, or an increase of 5.31%.

Q. How much additional net operating income would be required for the State of Idaho natural gas operations to allow the Company an opportunity to earn its proposed 7.62% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $1,970,000 for 2016 and $1,023,000 for 2017, as shown on line 5, page 3 of Exhibit No. 12, Schedule 2. The resulting revenue requirement is shown on line 7 and amounts to $3,205,000 for 2016, or an increase of 8.84% (4.48% on a billed basis), and $1,665,000 for 2017, or an increase of 4.22% (or 2.19% on a billed basis).

VI. ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last general electric and natural gas cases, Case Nos. AVU-E-12-08 and AVU-G-12-07?

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 annually 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.