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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-11-01 CASE NO. AVU-G-11-01 DIRECT TESTIMONY OF 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.

Q. As Manager of Revenue Requirements, what are your responsibilities?

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

A. As Manager of Revenue Requirements, aside from special projects, 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 ten and one-half years, I have assisted or led 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 generally cover accounting and financial data in support of the Company's need for the proposed increase in rates. I will explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base. I incorporate the Idaho share of the proposed adjustments of other witnesses in this case. In addition, I will explain the Company's request for deferred accounting treatment of changes in generating plant operation and maintenance (O&M) costs related to its Coyote Springs 2 natural gas-fired plant and its 15% ownership share of the Colstrip 3 & 4 coal-fired generating plants.

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

A. Yes. I am sponsoring Exhibit No. 10, Schedule 1 (Electric) and Schedule 2 (Natural Gas), which were prepared by me. These exhibits consist of worksheets, which show actual 2010 operating results (twelve-month period ending December 31, 2010), pro forma, and proposed electric and natural gas operating results and rate base for the State of Idaho. 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.

II. COMBINED REVENUE REQUIREMENT SUMMARY

Q. Would you please summarize the results of the Company's pro forma study for both the electric and natural gas operating systems for the Idaho jurisdiction?

A. Yes. 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 7.57% and 7.31%, respectively. Both return levels are below the Company's requested rate of return of 8.49%. The incremental revenue requirement necessary to give the Company an opportunity to earn its requested ROR is $9,009,000 for the electric operations and $1,921,000 for the natural gas operations. The overall base electric increase associated with this request is 3.66%. The base natural gas increase is 2.72%.

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

A. The Company's currently authorized rate of return for its Idaho operations is 8.55%, effective October 1, 2010 for both our electric and natural gas systems.

III. ELECTRIC SECTION

Test Period for Ratemaking Purposes

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, 2010, presented on a pro forma basis. Currently authorized rates were based upon the twelve-months ending December 31, 2009 test year utilized in AVU-E-10-01, adjusted on a pro forma basis.

Q. Could you please explain the different rates of return that you will be discussing in your testimony?

A. Yes. There are three different rates of return that will be discussed. The actual ROR earned by the Company during the 2010 test period of 9.11%[2] [3], the pro

[2] As shown on Exhibit 10, Schedule 1, this return includes deferred federal income taxes (DFIT) on plant rate base, excluding minor additional DFIT amounts associated with Coeur d'Alene, Spokane River Relicensing and Montana Riverbed Lease deferrals included in separate restating adjustments described later in my testimony.

[3] The Company will not have an opportunity to earn its current or requested allowed rate of return for the 2012 rate period without additional rate relief from this general rate case, due primarily to the 2011 and 2012 net increases in company expenditures included in the Company's filed case.

forma ROR of 7.24% (determined in my Exhibit No.10, Schedule 1) and the requested ROR of 8.49%.

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

A. Approximately 90% of the Company's revenue requirement requested in this case is due to an increase in Net Plant Investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest). This increase is due to an increase of approximately $21.0 million in net plant rate base for the Idaho jurisdiction.

The remaining 10% is due to increases in distribution, operation and maintenance (O&M), and administrative and general (A&G) expenses, offset by a reduction in net power supply and transmission expenditures.

Also impacting the Company's request, the Company has included an Energy Efficiency Load Adjustment (EELA) increasing the Company's revenue requirement by approximately $1.86 million. The reduced load from the EELA causes an increase in revenue requirement in each of the major cost categories because the foregone retail revenue from the load reduction is designed to recover costs in each of the categories.

Q. What were the major components of the increased net plant investment included in the Company's filing?

A. Looking at the changes to "gross" plant in service, Idaho "gross" plant increased by approximately

$66.2 million, as compared to what is currently included in rates. In order to meet the energy and reliability needs of our customers, $23.0 million of this increase is due to the Company's investment in thermal and hydro generating facilities, as well as additional transmission investment. Distribution "gross" plant increased $30.1 million above the current level included in rates, while general and intangible "gross" plant increased $13.1 million. After adjusting for accumulated depreciation and amortization, and accumulated deferred income taxes, the <u>net</u> increase to rate base from these items is approximately $21 million. Lastly, the Company included a working capital adjustment in this case of $7.7 million for fuel stock inventory, materials and supplies.

The specific 2011 and 2012 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. Lafferty regarding production assets, and Mr. Kinney regarding transmission and distribution assets. In addition to discussing the actual restating and pro forma adjustments made regarding net plant investment, Company witness Mr. DeFelice also describes all remaining 2011 and 2012 plant additions not described by Mr. Lafferty and Mr. Kinney.

Q. Mr. DeFelice explains the restating pro forma capital adjustments included in this case. Could you

please briefly describe the conclusions drawn by Mr. DeFelice regarding the increased capital investment?

A. Yes. As described in Mr. DeFelice's testimony, the Company is making substantial levels of capital 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 similar 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 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 has <u>decreased</u> by approximately $2.2 million ($6.4 million on a system basis) from the level <u>currently in base rates</u>.

This decrease in pro forma power supply expense over the expense currently in base rates is caused primarily by two factors, lower loads and lower market prices for natural gas and power. Loads are lower by 50.8 aMW from the authorized loads in current base rates, which used a pro forma load projection. The reduction in load is a result of using historical test-year loads and including the Energy Efficiency Load Adjustment. The reduction in load due to moving from a pro forma year load to a historical test-year load is 30.7 aMW and the reduction in load due to the Energy Efficiency Load Adjustment is 20.1 aMW. Mr. Johnson discusses in further detail the changes in power supply expenses.

Pro forma transmission expenditures increased due in part to approximately $747,000 of expenses in 2012 related to a North American Electric Reliability Corporation (NERC) Alert as discussed by Mr. Kinney.

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. A number of expense items have increased since the 2009 test year pro forma used in the last rate case. For example, employee benefits such as wages and medical insurance expenses have increased.

We are utilizing a 2010 test year, however, new general electric rates resulting from this filing are not expected to go into effect until late in 2011 or early

2012. Accordingly, the Company has included a number of pro forma adjustments to capture some of the cost changes that the Company will experience from the test year. In particular, the Company has pro formed in the increased costs associated with electric distribution vegetation management costs of approximately $1.3 million as discussed by Mr. Kinney, and increased medical expenses of approximately $658,000, discussed further below. These two adjustments alone equate to over 75% of the additional increases in distribution and other expense included in the Company's filing.

<u>Revenue Requirement</u>

Q. Would you please explain what is shown in Exhibit No. 10, Schedule 1?

A. Yes. Exhibit No. 10, Schedule 1, shows actual and pro forma electric operating results and rate base for the test period for the State of Idaho. Column (b) of page 1 of Exhibit No. 10, Schedule 1, shows 2010 actual operating results and components of the average-of-monthly-average rate base as recorded (prior to deferred taxes); column (c) is the total of all adjustments to net operating income and rate base; and column (d) is pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company to earn an 8.49% rate of return. Column (f) reflects pro forma electric operating results with the requested increase of $9,009,000. The restating adjustments shown in columns *(c)* through *(ag)*, of pages 5 through 11 of Exhibit No. 10, Schedule 1, are consistent with current regulatory principles and the treatment reflected in the prior Commission Order in Case No. AVU-E-10-01, with a few proposed changes by the Company as described in my testimony below.

Q. Would you please explain page 2 of Exhibit No. 10, Schedule 1?

A. Yes. Page 2 shows the calculation of the $9,009,000 revenue requirement at the requested 8.49% rate of return.

Q. What does page 3 of Exhibit No. 10, 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 8.49%. 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 Dr. Avera provides additional testimony related to the appropriate return on equity for Avista.

Q. Would you now please explain page 4 of Exhibit No. 10, 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 11 of your Exhibit No. 10, Schedule 1, would you please explain what those pages show?

A. Yes. Page 5 begins with actual operating results and rate base (prior to inclusion of deferred taxes) for the 2010 test period in column (b). Individual normalizing and restating adjustments that are standard components of our annual reporting to the Commission begin in column (c) on page 5 and continue through column (ag) on page 9. Individual pro forma adjustments begin in column (PF1) on page 10 and continue through column (PF12) on page 11. The final column on page 11 is the total pro forma operating results and net rate base for the test period.

<u>**Standard Commission Basis and Restating Adjustments**</u>

Q. Would you please explain each of these adjustments, the reason for the adjustment and its effect on test period State of Idaho net operating income and/or rate base?

A. Yes, but before I begin, I will note that 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.

The first adjustment, column (c) on page 5, entitled **Deferred FIT Rate Base**, reflects the rate base reduction for Idaho's portion of deferred taxes. The adjustment reflects the deferred tax balances arising from accelerated tax depreciation (Accelerated Cost Recovery System, or ACRS, and Modified Accelerated Cost Recovery, or MACRS) and bond refinancing premiums. These amounts are reflected on the average-of-monthly-average balance basis. The effect on Idaho rate base is a reduction of $104,677,000.

The adjustment in column (d), **Deferred Gain on Office Building**, reflects the removal of the amortization gain included in the Company's 2010 test period related to Idaho's portion of the amortized gain on the sale of the Company's general office facility. The facility was sold in December 1986 and leased back by the Company. Although the Company repurchased the building in November 2005, the deferred gain was amortized over the period ending in 2011. Therefore, during the 2012 rate period the average of monthly averages (AMA) amount of the deferred gain is zero. The effect on Idaho rate base is zero. The effect on Idaho net operating income is an increase of $43,000[4].

The adjustment in column (e), **Colstrip 3 AFUDC Elimination**, is a reallocation of rate base and

[4] During the process of completing the Company's filing the Company discovered it had inadvertently reduced expense for removal of the deferred gain included in the test period. Rather, this adjustment should have removed the gain, increasing expense, decreasing net operating income $43,000. The impact of correcting for this error increases the requested electric revenue requirement in this case by approximately $135,000.

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 U-1008-144 by the 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 rate base adjustment reflects the average-of-monthly-averages amount for the test period. The effect on Idaho net operating income is a decrease of $191,000. The effect of the reallocation on Idaho rate base is an increase of $1,493,000.

The adjustment in column (f), **Colstrip Common AFUDC**, 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. The rate base adjustment reflects the average-of-monthly-averages amount for the test period. The effect on Idaho rate base is an increase of $774,000.

The adjustment in column (g), **Kettle Falls & Boulder Park Disallowances**, decreases rate base. The amounts 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. This Commission 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. The effect on Idaho rate base is a decrease of $1,880,000.

The adjustment in column (h), **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. The effect on Idaho rate base is a decrease of $858,000.

Q. Please turn to page 6 and explain the adjustments shown there.

A. Page 6 starts with the adjustment in column (i), **Weatherization and DSM Investment**, which includes in rate base the Sandpoint weatherization grant balance (FERC account 124.350), and removes the 1994 DSM Program amortization expense included in the 2010 test period.

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. As no expense will be incurred during the 2012 rate year the 2010 amortization is being eliminated in this adjustment. The effect on Idaho rate base is an increase of $65,000. The effect on Idaho net operating income is an increase of $147,000.

The adjustment in column (j), **Restating CDA Settlement**, adjusts the 2010 AMA test period annual amortization expense, net asset ($41.6 million (system) of payments and deferred costs) and DFIT balances related to the 2008 through 2010 CDA Tribe Settlement payments (Past Storage/§10(e)) and deferred costs to a 2012 AMA basis.

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[5] Allowance for funds used to conserve energy.

The regulatory treatment of the CDA Settlement was approved by the Commission in Case No. AVU-E-09-01. The effect on Idaho rate base is a decrease of $317,000 below that in the test period. The effect on Idaho net operating income is a decrease of $19,000.

The adjustment in column (k), **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 to a 2012 AMA basis, and records the annual amortization expense based on a ten-year amortization, as approved in Docket No. AVU-E-10-01. The effect on Idaho rate base is an increase of $166,000. The effect on Idaho net operating income is a decrease of $12,000.

The adjustment in column (l), **Restating CDA/SRR (Spokane River Relicensing) CDR**, adjusts the net assets and DFIT balances associated with the CDA Tribe settlement 4(e) Spokane River relicensing conditions, deferred for future recovery, to a 2012 AMA basis. The expense portion of this adjustment includes the annual amortization of the net total asset ($12 million (system) of payments and deferred costs); amortization of the deferred balance over a ten-year period, as approved in Case No. AVU-E-10-01; and the annual $2 million (system) of Coeur d'Alene Reservation Trust Restoration Fund (CDR) payment expense over the 2010 AMA expense level. The effect on Idaho rate base is a decrease of $68,000. The effect on Idaho net operating income is a decrease of $223,000.

The adjustment in column (m), **Restating Spokane River Deferral**, adjusts the net asset and DFIT balances related to the Spokane River deferred relicensing costs to a 2012 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 Idaho rate base is an increase of $31,000. The effect on Idaho net operating income is a decrease of $2,000.

The adjustment in column (n), **Restating Spokane River PM&E Deferral**, adjusts the net asset and DFIT balances related to the Spokane River deferred PM&E costs to a 2012 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 Idaho rate base is an increase of $145,000. The effect on Idaho net operating income is a decrease of $13,000.

Q. Please turn to page 7 and explain the adjustments shown there.

A. Page 7 starts with the adjustment in column (o), **Restating Montana Riverbed Lease**, which 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. This adjustment includes amortization of one-eighth of the deferred balance and the adjustment to lease payment expense for the additional annual inflation. This adjustment decreases Idaho net operating income by $29,000 and increases rate base by $996,000.

The adjustment in column (p), **Working Capital**, increases total rate base for the Company's working capital adjustment. Cash Working capital represents the funds required to enable the Company to operate its business on a daily basis. The need for these funds results from the fact that there is a 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. Cash working capital represents investor supplied funds that are properly included in the Company's rate base for ratemaking purposes. Application of the overall rate of return to this element of rate base allows the Company to service the capital costs associated with the cash working capital.

Although there are various appropriate methods used to determine a Company's working capital, to reduce the issues in this case[6] the Company has calculated its working capital in this proceeding by including Idaho's electric portion of the 2010 average-monthly-average balances of FERC accounts 151 (Fuel Stock Inventory) and 154 (Plant Materials and Supplies). The Company believes this is a reasonable approach to working capital, representing specific items of expended funds to provide reliable service to its customers. The effect on Idaho rate base is an increase of $7,710,000.

The next column marked by a dash, entitled **Subtotal Actual** represents actual operating results and rate base plus standard rate base adjustments that are included in Commission Basis reporting, plus additional restating adjustments required to annualize previous approved rate base items.

Q. Please continue describing the adjustments on page 7 that continue after the Subtotal Actual column.

A. The adjustment in column (q), **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

[6] The Company, of course, reserves the right to argue a different methodology in a future proceeding if appropriate.

adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. B & O taxes are passed through on a separate schedule, which is not part of this proceeding. The effect of this adjustment is to decrease Idaho net operating income by $4,000.

The adjustment in column (r), **Property Tax**, restates the test period accrued levels of property taxes to the most current information available and eliminates any adjustments related to the prior year. The effect of this adjustment decreases Idaho net operating income by $309,000.

The adjustment in column (s), **Uncollectible Expense**, restates the accrued expense to the actual level of net write-offs for the test period. The effect of this adjustment is to increase Idaho net operating income by $102,000.

The adjustment in column (t), **Regulatory Expense**, which restates recorded 2010 regulatory expense to reflect the IPUC assessment rates applied to expected revenues for the test period period and the actual levels of FERC fees paid during the test period. The effect of this adjustment is to increase Idaho net operating income by $2,000.

The adjustment in column (u), **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. A six-year rolling