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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 net 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.

Revenue Requirement

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.

Standard Commission Basis and Restating Adjustments

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.

[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 average and the reserve method of accounting for injuries and damages, net of insurance proceeds, is a practical methodology to deal with these normal utility operating expenses that happen to occur on an irregular basis and differ markedly in materiality. 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 is to increase Idaho net operating income by $396,000.

Q. Please turn to page 8 and explain the adjustments shown there.

A. Page 8 starts with the adjustment in column (v), **FIT**, adjusts the FIT calculated at 35% within Results of Operations by removing the effect of certain Schedule M items, matching the jurisdictional allocation of other Schedule M items to related Results of Operations allocations and adjusts the appropriate level of production tax credits and income tax credits on qualified generation.

The net FIT and production tax credit adjustments decrease Idaho net operating income by $279,000. Adjusting for the proper level of deferred tax expense for the test period increases Idaho net operating income by $210,000. This adjustment also reflects the proper level of amortized income tax credit for the test period decreasing Idaho net operating income by an additional $8,000. Therefore, the net effect of this adjustment, all based upon a Federal tax rate of 35%, is to increase Idaho net operating income by $77,000.

The adjustment in column (w), **Idaho PCA**, removes the effects of the financial accounting for the Power Cost Adjustment (PCA). The PCA normalizes and defers certain power supply costs on an ongoing basis between general rate filings. 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 a normal period. Actual revenues and power supply costs are normalized in adjustments in column (w) and column (PF1), respectively. The effect of this adjustment is to decrease Idaho net operating income by $6,415,000.

The adjustment in column (x), **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 is to increase Idaho net operating income by $11,000.

The adjustment in column (y), **Eliminate A/R Expenses**, removes expenses incurred associated with the fees charged the Company for its customer accounts receivable program. The Company's accounts receivable program was terminated in December 2010. The effect of this adjustment is to increase Idaho net operating income by $79,000.

The adjustment in column (z), **Revenue Normalization**, is an adjustment taking into account known and measurable changes that include revenue repricing (including the current authorized rates approved in Case No. AVU-E-10-01), weather normalization and a recalculation of unbilled revenue. Schedule 91 Tariff Rider and Schedule 59 Residential Exchange are excluded from pro forma revenues, and the related amortization expense is eliminated as well. Company witness Ms. Knox is sponsoring this adjustment. The effect of this particular adjustment is to increase Idaho net operating income by $11,504,000.

The adjustment in column (aa), is the Company's **Miscellaneous Restating Adjustment**. For this adjustment, the Company completed an extensive review of its 2010 expenditures included in its test period, removing 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, totaling approximately $143,000.

The Company also removed 10% of Avista Corp. director fees (and 100% of director fees associated with Advantage IQ) totaling approximately $35,000. Lastly, this adjustment removes Idaho's electric portion of consulting services, totaling approximately $770,000 from the test period to reduce the revenue requirement requested in this case. The detail of these adjustments can be found within my workpapers. The effect of this adjustment is to increase Idaho net operating income by $606,000.

Q. As noted above, the Company removed 10% of Avista Corp. director fee expenses. What is the basis for removing 10% of these costs?

A. In 2010 the Company requested from each of its directors, based on their actual experience, the estimated time spent on utility versus non-utility duties and responsibilities. The responses from the Directors indicated that approximately 90% of the Directors' time is dedicated to utility matters, and approximately 10% to non-utility.

This 90/10 split is consistent with the average split that has been used in recent years by Avista's senior officers. Director fees paid to board members for their duties specific to other Avista boards, i.e. Advantage I.Q., were also removed. Using a 90/10 sharing for the remaining director fees paid for participating in Avista

Corp./Utility board meetings reduced the Company's expense included in this filing by approximately $35,000.

Q. Please turn to page 9 and explain the adjustments shown there.

A. Page 9 starts with the adjustment in column (ab), **Restating Incentives**, which restates the actual employee payroll incentives included in the Company's test period using a six-year average adjusted by the Consumer Price Index. The effect of this adjustment is to increase Idaho net operating income by $631,000.

Q. Please briefly explain the Company's incentive plan.

A. Avista's current incentive plan was first designed in 2002, the goal of which was to focus on three key elements: cost control, customer satisfaction and the reliability of the energy we provide to our customers. The Employee Incentive Plan is a pay-at-risk plan whereby employees are eligible to receive cash incentive pay if the stated targets are achieved. The plan encourages employees at all levels to focus on common objectives that are designed to align the interests of employees with the interests of our customers. Establishing specific targets for each element, measuring progress toward meeting the targets, and paying an incentive for achieving them motivates employees to focus on the key elements each year.

Q. How is the pay-at-risk component incorporated into Avista's total compensation package for employees?

A. Avista is committed to providing a total compensation program that provides base salaries, performance-based award programs and benefits that are competitive in the marketplace. Market data shows that pay-at-risk or variable pay plans are prevalent in over 80% of organizations, and most utilities, including Avista, have some kind of pay-at-risk plan.

The Company views the Plan as a competitive necessity, and a driver of desired behavior among employees, as well as a means to achieve cost-control. For example, if the existing incentive plan were to be eliminated, base salaries would need to be adjusted in order for Avista's total compensation to remain competitive with other utilities.

A 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 making decisions that benefit the Company and its customers, while at the same time functioning as an integrated component of total compensation.

Q. Please describe the specific targets included in the Company's 2010 incentive plan?

A. The targets included in the Company's 2010 plan included: 1) an O&M cost per customer target metric to focus the business on controlling costs and driving efficiencies in order to keep our costs reasonable for our customers; 2) use of a Customer Satisfaction rating to track satisfaction levels of customers that have had recent contact with us; and 3) a reliability index measure, which combines three common industry indices in order to balance our focus on electric reliability. These reliability measures include: the Customer Average Interruption Duration Index (CAIDI), measuring the average restoration time for sustained outages; the System Average Interruption Frequency Index (SAIFI), which measures the average number of customers who had sustained outages (>5 minutes), divided by the customers served; and the Customer Experiencing Multiple Sustained Interruptions (more than 3) (CEMI[3]), measuring the percentage of customers that experienced more than three sustained outages in the year.

Each of these targets are independent components to the incentive plan with individual targets or measures that must be achieved for a portion of the payout. The customer satisfaction and reliability index measures are core objectives to our business therefore; these non-financial measures are designed as a "meets" or "not meets" metric, paying out only if the target of "meets" is achieved.

The O&M cost per customer target is based on the projected number of customers, targeted O&M expense and a savings mechanism between employees and the Company. This measure provides an incentive for employees to keep actual O&M costs as low as possible. Payments under this portion of the plan can range from 0% to 150% depending on the level of performance achieved. In 2010 the company added a sharing mechanism to the cost per customer target, sharing costs savings at certain levels between employees and customers.

Q. Please explain the use of a six-year average to restate incentive expense.

A. Since annual Company incentive plan payouts can often vary year-to-year, the Company believes an average of annual payouts is most appropriate in order to "normalize" these costs. Often where there are revenues or expenses that can vary significantly from year-to-year, the Commission has approved averages to properly reflect a fair and reasonable level of revenue or expense to be included in customers' rates. Utilizing a six-year average of the Company's incentive plan payouts is consistent with other averaging methods utilized by this Commission in past proceedings. For example, as shown in the table below using the years 2005 through 2010, one can see the large variability that can occur in each year in payout, and therefore the variability in customer rates if an average was not utilized, and the impact of the six-year average as proposed in this case:

Illustration No. 1 (System)

Six-Year Average of Incentive Plan Payout	
*6-Year Average - 2010 GRC (Millions)	
2005	$6.2
2006	$4.7
2007	$3.4
2008	$2.9
2009	$5.1
2010	$9.4
6-Yr Average	$5.3
Test Year Incentive Exp.	$9.4
Restating Adjustment	($4.1)
*Includes payroll taxes and adjustment for CPI	

In this instance, the table above reflects a restating reduction to test period expense of $4.1 million (system), showing a significant fluctuation in the level of expense between periods supporting the argument that use of an averaging methodology is appropriate.

Q. What are some other examples where the use of an average has been used by the Company, and approved by the Commission, to determine the appropriate level of revenue or expense to include in its general rate case filings?

A. There are several examples of revenue or expense amounts which have been averaged or normalized and approved by this Commission. One example is the calculation of injuries and damages expense, which includes the restating adjustment described earlier in my testimony that replaces the amount accrued in the test period with a six-year rolling average of actual payments for injuries and damages not covered by insurance. Another example is the use of a five-year average for power plant availability.

Q. Briefly explain the reasoning behind the use of the CPI to adjust the average incentive level.

A. Incentive compensation is based on employees salary levels at the time of payout. These salary levels increase over time. If one does not adjust the historical years' expenses so that they are based on a comparable level of salaries, when the calculation is computed to determine the average, one is not using comparable levels of expenses in order to get to an "apples to apples" comparison.

Q. What is the impact of the Company's adjustment for a six-year average in this case?

A. The Company adjusted the six-year average by the CPI explained above, but also excluded all incentive target payouts that are not specifically related to reliability, customer service and operational efficiency targets, i.e., the earnings per share portion of the officer incentive plan are excluded from utility expenditures. The adjusted six-year average reduces the Company's electric and natural gas revenue requirement by approximately $989,000 and $249,000 respectively.

Q. Please continue with explaining the adjustments on Page 9 of Exhibit 10, Schedule 1.

A. The adjustment in column (ac), **Restating CS2 Levelized Adjustment**, adjusts the deferred return amounts related to Coyote Springs 2 (CS2) to the amounts that will be recorded during the rate year. 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 runs from September 1, 2004 through August 31, 2014. This adjustment restates the test period amount of amortization expense, inclusive of the carrying charge on the deferred return, to the amount that will be recorded in the rate year. The change in deferred income tax expense from the test period to the rate period is also reflected. This adjustment reduces net operating income by $182,000.

The adjustment in column (ad), **Removal Colstrip Lawsuit Settlement**, reflects the removal of the amortization of the Company's share of the lawsuit settlement amount included in the 2010 test period. In Case No. AVU-E-09-01 the Idaho Commission approved the two-year amortization treatment proposed by the Company starting in August 1, 2009 through July 31, 2011. In July, 2010, Avista received insurance proceeds recovering the majority of the amount yet to be amortized and recovered from customers. This adjustment removes the test period expense amount since the amortization period is complete prior to the 2012 rate period. This adjustment increases Idaho net operating income by $148,000.

The adjustment in column (ae), **Removal Chicago Climate Exchange**, removes the effect in the test period of amortization revenue included related to the expiration of the two-year amortization of the Chicago Climate Exchange approved in AVU-08-01. In AVU-08-01 the IPUC approved a two-year amortization (beginning in October 2008 through September 2010) of the other revenue included in Idaho's share of the revenues, net of expenses, from the sales of Carbon Financial Instruments (CFIs) on the Chicago Climate Exchange. This adjustment decreases Idaho net operating income by $219,000.

The adjustment in column (af), **Operation & Maintenance (O&M) Savings**, includes a reduction to expense for anticipated operation and maintenance savings expected during the pro forma period, as compared to the 2010 test period. These O&M savings include reductions related to certain additional generation, transmission, distribution and general plant investment included in the 2010, 2011 and 2012 capital addition adjustments. The savings related to capital projects have been discussed further within Mr. Lafferty's (generation projects), Mr. Kinney's (distribution and transmission projects), and Mr. DeFelice's (general plant) direct testimony. Additional detail can be found within my workpapers included with the

Company's filing. This adjustment increases Idaho net operating income by $101,000.

The adjustment in column (ag), **Restate Debt Interest,** restates debt interest using the Company's pro forma weighted average cost of debt, as outlined in the testimony and exhibits of Mr. Thies. As applied to Idaho's pro forma level of rate base, this produces a pro forma level of tax deductible interest expense. The Federal income tax effect of the restated level of interest for the test period decreases Idaho net operating income by $276,000.

The last column on page 9, entitled **Restated Total,** subtotals all the preceding columns (b) through column (ag), excluding the subtotal column. These totals represent actual operating results and rate base plus the standard normalizing adjustments that the Company includes in its annual Commission Basis reports, except power supply.[7]

<u>Pro Forma Adjustments</u>

Q. Please explain the significance of the 12 columns beginning at page 10 on your Exhibit No. 10, Schedule 1.

A. The adjustments starting on page 10 are pro forma adjustments that recognize the jurisdictional impacts of items that will impact the pro forma operating period for

[7] The restated total also includes an increase in expense necessary to annualize certain 2010 expenses included in the test period as restating adjustments, (i.e. Montana riverbed lease, Spokane River and CDA Tribe Settlement expense), and includes a reduction to expense for a 6-year average of incentives.

known and measurable changes. They encompass revenue and expense items as well as additional capital projects. These adjustments bring the operating results and rate base to the final pro forma level for the test year.

Q. Please continue with your explanation of the adjustments starting on page 10.

A. The adjustment in column (PF1), **Pro Forma Power Supply**, 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, 2012 through December 31, 2012, using historical loads. Mr. Johnson's testimony outlines the system level of pro forma power supply revenues and expenses that are included in this adjustment.[8] The adjustment in column PF1 calculates the Idaho jurisdictional share of those figures. The net effect of the power supply adjustments decrease Idaho net operating income by $5,840,000.

The adjustment in column (PF2), **Pro Forma Energy Efficiency Load Adjustment**, reflects the reduction in retail revenues due to energy efficiency programs, the resulting savings in power supply expense, and includes the change in all other revenue related expenses and taxes

[8] Mr. Johnson also explains the Company's use of historical loads in this case and the impact of the Energy Efficiency Load Adjustment described in adjustment PF2, rather than the use of pro forma loads used in the previous Company Case No. AVU-E-10-01. Due to the use of historical loads, the Company has also excluded the Production Property adjustment included in the Company's prior Case No. AVU-E-10-01.

associated with this adjustment, as described in detail by Mr. Ehrbar. The effect of this adjustment on Idaho net operating income is a decrease of $1,184,000.

The adjustment in column (PF3), **Pro Forma Labor-Non-Exec**, reflects known and measurable changes to test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in adjustment PF4. For non-union employees, test period wages and salaries are restated to include the March 2011 overall actual increase of 2.8%, and 10 months of the planned March 2012 minimum increase of 2.5%. This 2012 minimum increase was presented to the Compensation Committee of the Board of Directors and was approved at the Board's May 2011 meeting.

Also included in this adjustment are the 2011 and 2012 union contract increases agreed to in 2010 of 3% for both years. The methodology behind this adjustment is consistent with that used in Case No. AVU-E-10-01. The effect of this adjustment on Idaho net operating income is a decrease of $625,000.

The adjustment in column (PF4), **Pro Forma Labor-Executive**, reflects known and measurable changes to executive compensation, restating executive compensation test period salary expense to actual salary levels at 2011. This adjustment reflects the annual increase for the actual overall 2011 officer increase of 3.79%. Compensation costs for non-utility operations are excluded, as executives routinely charge a portion of their time to non-utility operations, commensurate with the amount of time spent on such activities, based on a survey of each executive. The methodology behind this adjustment is consistent with that used in Case No. AVU-E-10-01. The effect of this adjustment on Idaho net operating income is a decrease of $10,000.

The adjustment in column (PF5), **Pro Forma Transmission Rev/Exp**, was made under the direction of Mr. Kinney 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, 2012 through December 31, 2012. The net effect of the transmission revenue and expense adjustments decreases Idaho net operating income by $760,000.

The adjustment in column (PF6), **Pro Forma Capital Additions 2010**, pro forms in the capital cost and expenses associated with adjusting the 2010 average-of-monthly-average (AMA) plant related balances to end-of-period (EOP) balances for plant in service at December 31, 2010. The capital costs have been included for the December 31, 2010 pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment is consistent with that included in the most recent Idaho general rate case proceeding, Case No. AVU-E-

10-01. This adjustment decreases Idaho net operating income by $419,000 and increases rate base by $11,643,000.

Q. Please now turn to page 11 and continue with your explanation of the adjustments included on that page.

A. Column (PF7), **Pro Forma Capital Additions 2011,** pro forms in the capital cost and expenses associated with capital expenditures for 2011. This adjustment includes projects expected to be completed and transferred to plant-in-service by December 31, 2011, and thus were normalized to reflect annual amounts. The capital costs have been included for the appropriate pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. In addition, the <u>total</u> plant in service at December 31, 2010 (including accumulated depreciation and deferred FIT) was adjusted to an EOP December 31, 2011 adjusted balance. This adjustment was also made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Idaho net operating income by $1,941,000 and increases rate base by $11,578,000.

Column (PF8), **Pro Forma Capital Additions 2012,** pro forms in the capital cost and expenses associated with capital expenditures for 2012. This adjustment includes projects expected to be completed and transferred to plant-in-service during 2012, and thus were included on an AMA plant basis for the 2012 rate period. The capital costs have been included for the appropriate pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. In addition, the <u>total</u> plant in service at December 31, 2011 (including accumulated depreciation and deferred FIT) was adjusted to a 2012 AMA plant basis. This adjustment was also made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Idaho net operating income by $394,000 and <u>decreases</u> rate base by $2,043,000.

The adjustment in column (PF9), **Pro Forma Noxon Generation 2011/2012**, pro forms in the 2011 Noxon Unit #2 generation plant upgrade (included in the 2010 rate case), and the 2012 Noxon Unit #4 generation plant upgrade at a 2012 AMA basis, as explained further by Mr. Lafferty. These Noxon upgrades are not included in the 2011 and 2012 capital additions explained above.

These unit upgrades are planned to increase unit efficiency and boost unit ratings. The additional generation from the Noxon Unit #2 and Unit #4, (Unit #2 completed in May 2011, and Unit #4 planned for May 2012) has also been included in the Aurora Dispatch Model for the rate year, as discussed by Company witness Mr. Kalich. Including the additional generation from these Noxon upgrades in the Dispatch Model, ultimately reducing power supply expenses for customers in the 2012 rate year, and including these project in rate base for the rate period, provides a proper match in revenues with expenses for these projects. The Noxon Unit #4 project was included in rate base and within the Aurora model at approximately 67% of the cost and generation (equivalent to 8 months due to a May 1, 2012 in-service date). This adjustment decreases Idaho net operating income by $113,000 and increases rate base by $4,650,000.

The adjustment in column (PF10), **Pro Forma Employee Benefits**, adjusts for changes in both the Company's pension and medical insurance expense and decreases Idaho net operating income by $433,000.

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 this adjustment is determined in accordance with Financial Accounting Standard 87 ("FAS-87"), and has remained fairly flat on a system basis from approximately $19.5 million for the actual test year costs for the twelve months ended December 31, 2010, to $19.6 million for 2011. At this time the amounts included in this case are based on the most current available data. Preliminary Pension expense is determined by an outside actuarial firm, in accordance with FAS-87, and provided to the Company late in the first quarter of each year. These calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other companies. Due to the timing of this report, additional information may become known during the course of these proceedings that may require a modification to this adjustment.

Changes in pension expense typically are due primarily to the investment performance of plan assets during the past year. In addition, the Pension Protection Act (PPA) of 2006 requires companies to annually increase the funding level of their pension plans in order to eventually achieve a fully-funded plan, which also impacts the plan asset balance and level of expense.

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

A. The Company's medical insurance expense is the majority portion of this adjustment, adjusting for the medical insurance costs planned for 2011 above the test period. Medical insurance expense has increased on a system basis from $20.54 million for the actual test year costs for the twelve months ended December 31, 2010, to $25.27 million for 2011. This increase in medical cost is due to an aging workforce requiring more health care at an ever increasing cost, which is consistent with what is occurring on a national level. Large claims activity driven by various diagnostic categories such as cancer and heart disease are also to blame for a portion of the increase.

The net impact of the change in medical and pension costs is an increase in Idaho expense of approximately $666,000.

Q. Please continue your explanation of the adjustment columns on page 11.

A. The adjustment in Column (PF11), **Pro Forma Insurance**, adjusts the test period insurance expense for general liability, directors and officers ("D&O") liability, and property to the actual cost of insurance policies that are in effect for 2011. Costs of system-wide insurance policies for 2011 varied only slightly from those policies in 2010. Insurance costs that are properly charged to non-utility operations have been excluded from this adjustment. This adjustment increases Idaho net operating income by $30,000.

The adjustment in column (PF12), **Pro Forma Vegetation Management**, pro forms in the additional distribution vegetation management (VM) O&M expense needed to reduce the distribution VM cycle (expense level) to a four-year cycle (expense level) to be used in 2012, as described further by Mr. Kinney. This adjustment decreases Idaho net operating income by $822,000.

The last column, Pro Forma Total, reflects total pro forma results of operations and rate base consisting of test period actual results (twelve-months ending December 31, 2010) and the total of all adjustments.

Q. Referring back to page 1, line 42, of Exhibit No. 10, Schedule 1, what was the pro forma electric rate of return by the Company during the test period?

A. For the State of Idaho, the pro forma rate of return is 7.57% under present rates. Thus, the Company does not, on a pro forma basis for the test period, realize the 8.49% rate of return requested by the Company in this case.

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 8.49% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $5,746,000, as shown on line 5, page 2 of Exhibit No. 10, Schedule 1. The resulting revenue requirement is shown on line 7 and amounts to $9,009,000, or an increase of 3.66% over pro forma general business revenues.

IV. NATURAL GAS SECTION

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

Q. When was the last change to base rates in the Idaho jurisdiction?

A. The last change to base gas rates in Idaho occurred on October 1, 2010 as a result of the Order received in Case No. AVU-G-10-01.

Q. Could you please explain the different rates of return shown in your natural gas results presented in your testimony?

A. Yes. As discussed previously in the Electric Section, there are three different rates of return calculated. The actual ROR earned by the Company during the 2010 test period of 7.21%[9], the pro 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 additional natural gas revenues?

A. The Company's natural gas request is driven by changes in various operating cost components, approximately two-thirds distribution O&M and A&G expenditures, such as increased costs in employee benefits, i.e. wages and medical insurance expenses, and one-third increased net plant investment, due to additional Company investment in underground storage facilities, distribution and general plant.

The total of the increased operating cost components

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[9] As shown on Exhibit 10, Schedule 1, this return includes deferred federal income taxes (DFIT) on plant rate base.

requested in this case causes an increase in the fixed costs of providing gas service to customers. I describe the pro forma adjustments included in this case later in my testimony.

<u>**Revenue Requirement**</u>

Q. Would you please explain what is shown in Exhibit No. 10, Schedule 2?

A. Yes. Exhibit No. 10, Schedule 2 shows actual and pro forma gas operating results and rate base for the test period for the State of Idaho. Column (b) of page 1 of Exhibit No. 10, Schedule 2, 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 gas operating results with the requested increase of $1,921,000.

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

A. Yes. Page 2 shows the calculation of the $1,921,000 revenue requirement at the requested 8.49% rate of return.

Q. What does page 3 of Exhibit No. 10, Schedule 2 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 calculation of 8.49%. Mr. Thies discusses the Company's proposed rate of return and the pro forma capital structure utilized in this case, while 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 2?

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

Q. Now turning to pages 5 through 9 of your Exhibit No. 10, Schedule 2, 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 adjustments that are standard components of our annual reporting to the Commission begin in column (c) on page 5 and continue through column (t) on page 8[10]. Individual pro

[10] The restated total also includes an increase in rate base necessary to include the Company's requested working capital adjustment, and includes a reduction to expense for a 6-year average of incentives.

forma adjustments begin in column (PF1) on page 8 and continue through column (PF10) on page 9. The final column on page 9 is the total pro forma operating results and rate base for the test period.

Standard Commission Basis Adjustments

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 outlining additional details related to each of the adjustments. The restating adjustments shown in columns (c) through (t) are consistent with methodologies employed in our prior cases and current regulatory principles, with a few proposed changes as described further in my testimony.

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), bond refinancing premiums, and contributions in aid of construction. These amounts are reflected on the average of monthly average balance basis. The effect on Idaho rate base is a reduction of $19,934,000.

The adjustment in column (d), **Deferred Gain on Office Building**, reflects the removal of the amortization expense 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 $14,000[11].

The adjustment in column (e), **Gas Inventory**, reflects the adjustment to rate base for the average-of-monthly-average value of gas stored at the Company's Jackson Prairie underground storage facility through the test period. The effect on Idaho rate base is an increase of $4,509,000.

The adjustment in column (f), **Weatherization and DSM Investment**, removes the amortization expense included in the test period due to the weatherization and DSM

[11] 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 $14,000. The impact of correcting for this error increases the requested electric revenue requirement in this case by approximately $44,000.

investment rate base being fully amortized in 2010. The effect of this adjustment is to increase Idaho net operating income by $64,000.

The adjustment in column (g), entitled **Customer Advances**, decreases rate base for funds advanced by customers for line extensions, as they are generally recorded as contributions in aid of construction at some future time. The effect of this adjustment on Idaho rate base is a decrease of $74,000.

Q. Please turn to page 6 and explain the first column shown there, and the adjustments that follow.

A. The first column on page 6 is adjustment (h), **Working Capital**, which increases total rate base for the Company's working capital adjustment described further in the Electric Section above. The Company has calculated its gas working capital by including Idaho's gas portion of the 2010 average-monthly-average balances of FERC accounts 151 (Fuel Stock Inventory) and 154 (Plant Materials and Supplies). The effect on Idaho rate base is an increase of $1,553,000.

The next column marked by a dash and labeled **Subtotal Actual**, is a subtotal of columns (b) through (h) and reflects the standard rate base adjustments, e.g., adjustments that reflect rate base items previously addressed by the Commission.[12]

[12] This subtotal also includes an increase in rate base necessary to include the Company's requested working capital adjustment.

The next adjustment on page 6 in column (i), entitled **Revenue Normalization**, is an adjustment taking into account known and measurable changes that include revenue normalization (including the current authorized rates approved in Case No. AVU-G-10-01), which reprices customer usage under presently effective rates, as well as weather normalization and an unbilled revenue calculation. Associated gas costs are replaced with gas costs computed using normalized volumes at the currently effective weighted-average-cost-of-gas, or WACOG rates in Schedule 150. Revenues associated with the temporary Gas Rate Adjustment Schedule 155, Schedule 191 Tariff Rider, and Schedule 199 Deferred SIT Adjustment are excluded from pro forma revenues, and the related amortization expenses are eliminated as well. Ms. Knox is sponsoring this adjustment. The effect of this particular adjustment is to increase Idaho net operating income by $1,189,000.

The adjustment in column (j), **Eliminate B & O Taxes**, eliminates the revenues and expenses associated with local business and occupation taxes, which the Company passes through to customers. The adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. B & O Taxes are passed through on a separate schedule, which is not part of this proceeding. The effect of this adjustment decreases Idaho net operating income by $1,000.

The adjustment in column (k), **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 $23,000.

The adjustment in column (l), **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 $155,000.

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

A. The first adjustment on page 7 in column (m), entitled **Regulatory Expense Adjustment**, restates recorded 2010 regulatory expense to reflect the IPUC assessment rates applied to revenues for the test period. The effect of this adjustment is to increase Idaho net operating income by $26,000.

The adjustment in column (n), entitled **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 is to increase Idaho net operating income by $31,000.

The adjustment in column (o), entitled **FIT**, adjusts the FIT calculated at 35% within Results of Operations by removing the effect of certain Schedule M items and matches the jurisdictional allocation of other Schedule M items to related Results of Operations allocations. This adjustment also reflects the proper level of deferred tax expense for the test period. The effect of this adjustment, all based upon a Federal tax rate of 35%, is to increase Idaho net operating income by $2,000.

The adjustment in column (p), **Eliminate A/R Expenses**, removes expenses incurred associated with the fees charged the Company for its customer accounts receivable program. The Company's accounts receivable program was terminated in December 2010 as explained by Mr. Thies. The effect of this adjustment is to increase Idaho net operating income by $13,000.

The adjustment in column (q) is titled **Miscellaneous Restating Adjustments**. This adjustment removes a number of non-operating or non-utility expenses, and removes or restates other expenses incorrectly charged between service and or jurisdiction, totaling approximately $21,000.

The Company also removed 10% of Avista Corp. director fees (and 100% of director fees associated with Advantage IQ) totaling approximately $9,000. Lastly, this adjustment removes Idaho's gas portion of consulting services, totaling approximately $194,100 from the test period to reduce the revenue requirement requested in this case.

This adjustment is described further in the Electric Section above and the detail of these adjustments can be found within my workpapers. The effect of this adjustment is to increase Idaho net operating income by $144,000.

The adjustment in column (r), **Restating Incentives,** restates the actual incentives included in the Company's test period using a six-year average adjusted by the Consumer Price Index. This adjustment is described further in the Electric Section above. The effect of this adjustment is to increase Idaho net operating income by $159,000.

The adjustment in column (s), **Operation & Maintenance (O&M) Savings,** includes a reduction to expense for anticipated operation and maintenance savings expected during the pro forma period, as compared to the 2010 test period. These O&M savings include reductions related to certain additional general plant investment included in the capital additions adjustments. Mr. DeFelice describes the general plant savings within his direct testimony and additional detail can be found within his workpapers included with the Company's filing. This adjustment increases Idaho net operating income by $4,000.

Q. Please turn to page 8 and explain the adjustments shown there.

A The first adjustment on page 8, column (t) entitled, **Restate Debt Interest**, restates debt interest using the Company's pro forma weighted average cost of debt, as outlined in the testimony and exhibits of Mr. Thies. As applied to Idaho's pro forma level of rate base, it produces a pro forma level of tax deductible interest expense. The federal income tax effect of the restated level of interest for the test period decreases Idaho's net operating income by $77,000.

The next column on page 8, entitled **Restated Total,** subtotals all the preceding columns (b) through column (t), excluding the subtotal column. These totals represent actual operating results and rate base plus the standard normalizing adjustments.[13]

Pro Forma Adjustments

Q. Please explain the significance of the 10 columns subsequent to the Restated Total column on pages 8 through 9 of your Exhibit No. 10, Schedule 2.

A. The adjustments starting on page 8 are pro forma adjustments to reflect known and measurable changes between the test period and the pro forma period. In this case, they encompass revenue and expense items, and natural gas inventory and capital projects. These adjustments bring the operating results and rate base to the final pro forma level for the test year.

Q. Please continue with your explanation of the adjustments on page 8.

[13] The restated total also includes an increase in rate base necessary to include the Company's requested working capital adjustment, and includes a reduction to expense for a 6-year average of incentives.

A. The first adjustment on page 8 in column (PF1), **Pro Forma Labor-Non-Exec**, reflects known and measurable changes to test period union and non-union wages and salaries, excluding executive salaries, which are handled separately in adjustment PF2. This adjustment is described further in the Electric Section above. The effect of this adjustment is to decrease Idaho net operating income by $155,000.

The adjustment in column (PF2), **Pro Forma Labor-Executive**, reflects known and measurable changes to executive compensation, restating executive compensation test period salary expense to actual salary levels at 2011. This adjustment is described further in the Electric Section above. The methodology behind this adjustment is consistent with that used in Case No. AVU-G-10-01. The effect of this adjustment on Idaho net operating income is a decrease of $14,000.

The adjustment in column (PF3), **Pro Forma Employee Benefits**, adjusts for changes in both the Company's pension and medical insurance expense (as explained in the Electric Section above) and decreases Idaho net operating income by $109,000.

The adjustment in Column (PF4), **Pro Forma Insurance,** adjusts the test period insurance expense for general liability, directors and officers (D&O) liability, and property to the actual cost of insurance policies that are in effect for 2011 (as explained in the Electric Section above). This adjustment increases Idaho net operating income by $8,000.

The adjustment in column (PF5), **Pro Forma Survey & Replacement Programs,** pro forms additional incremental operating and maintenance labor expense related to survey and replacement programs starting in 2011. The Company is implementing a special cathodic protection program for the purpose of finding and addressing isolated steel in its natural gas piping systems. This adjustment was made under the direction of Company witness Mr. Kopczynski and is described further in his testimony. This adjustment decreases Idaho net operating income by $106,000.

Q. Please turn to page 9 and explain the adjustments shown there.

A. The first adjustment on Page 9 in column (PF6), entitled **Pro Forma Atmospheric Testing**, adjusts the test period expense for Atmospheric Corrosion expense. This is an inspection program to find conditions in the Company's system that could lead to corrosion issues on customer meter sets. This program is a federally-mandated program that requires the Company to inspect all above ground steel pipe at a frequency not to exceed three-years. This expense is on a three-year rotation between the Company's jurisdictions (Idaho, Washington and Oregon) and is therefore, coded directly to Idaho operations for the year in which the inspection occurs (2011 for Idaho estimated at a total cost of $450,000). The Company is proposing to collect one-third of these costs over a three-year basis (2012-2014), and, therefore, has pro formed $150,000 for atmospheric O&M expense. The Company has received approval of this accounting treatment in its Oregon jurisdiction and has requested this treatment in the Company's recent filed Washington general rate case as well, so the Company remains whole on an annual basis. This adjustment was made under the direction of Mr. Kopczynski and is described further in his testimony. This adjustment decreases Idaho net operating income by $86,000.

The adjustment in column (PF7), **Pro Forma Capital Additions 2010**, pro forms in the capital cost and expenses associated with adjusting the 2010 average-of-monthly-average (AMA) plant related balances to end-of-period (EOP) balances for plant in service at December 31, 2010. The capital costs have been included for the December 31, 2010 pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment is consistent with that included in the most recent Idaho general rate case proceeding, Case No. AVU-G-10-01. This adjustment decreases Idaho net operating income by $104,000 and <u>decreases</u> rate base by $497,000.

The adjustment in column (PF8), **Pro Forma Capital Additions 2011**, pro forms in the capital cost and expenses associated with capital expenditures for 2011. This adjustment includes projects expected to be completed and transferred to plant-in-service by December 31, 2011, and thus were normalized to reflect annual amounts. The capital costs have been included for the appropriate pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. In addition, the <u>total</u> plant in service at December 31, 2010 (including accumulated depreciation and deferred FIT) was adjusted to an EOP December 31, 2011 adjusted balance. This adjustment was also made under the direction of Mr. DeFelice, is described further in his testimony, and is consistent with that included in the most recent Idaho general rate case proceeding, Case No. AVU-G-10-01. This adjustment decreases Idaho net operating income by $304,000 and <u>decreases</u> rate base by $2,297,000.

The adjustment in column (PF9), **Pro Forma Capital Additions 2012**, pro forms in the capital cost and expenses associated with capital expenditures for 2012. This adjustment includes projects expected to be completed and transferred to plant-in-service during 2012, and thus were included on an AMA plant basis for the 2012 rate period. The capital costs have been included for the appropriate pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. In addition, the <u>total</u> plant in service at December 31, 2011 was adjusted to a 2012 AMA balance. This adjustment was also made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Idaho net operating income by $64,000 and <u>decreases</u> rate base by $687,000.

The adjustment in column (PF10), **Pro Forma JP Storage 2011**, pro forms expenses, capital investment and inventory for the increased storage capacity and deliverability associated with the transfer of a portion of the Jackson Prairie (JP) Storage facility to the utility on May 1, 2011. System assets with a net book value of approximately $11.6 million transferred to the utility on May 1, 2011, comprised of approximately $5.9 million of cushion gas and approximately $5.7 million of fixed assets. The accounting treatment of the JP cushion gas recorded in both recoverable and non-recoverable FERC accounts, and the increases related to the additional plant, inventory and O&M expenses were approved in Case No. AVU-G-10-01, Order No. 32070, Settlement Stipulation, page 11, section III.17(c).

Idaho's share of these assets on a 2012 average-of-monthly-average basis increases net rate base by approximately $1.6 million. The adjustment also includes a rate base increase of $3.2 million for the working gas and recoverable cushion gas inventory associated with the 2011 additional storage. In addition, underground storage expense increased for the additional operating, depreciation and property taxes expense by approximately $209,000.

Company witness Mr. Christie provides an overview of the Jackson Prairie natural gas storage facility within his testimony. The details of this adjustment can be found within my workpapers included with the Company's filing. The impact of this adjustment decreases Idaho net operating income by $134,000 and increases rate base by $4,879,000.

The last column on page 9, **Pro Forma Total**, reflects total pro forma results of operations and rate base consisting of twelve-months ended December 31, 2010 actual results and the total of all normalizing, restating and pro forma adjustments.

Q. Referring back to page 1, line 44, of Exhibit No. 10, Schedule 2, what was the pro forma gas rate of return realized by the Company during the test period?

A. For the State of Idaho, the pro forma rate of return is 7.31% under present rates. Thus, the Company does not, on a pro forma basis for the test period, realize the 8.49% rate of return requested by the Company in this case.

Q. How much additional net operating income would be required for the State of Idaho gas operations to allow the Company an opportunity to earn its proposed 8.49% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $1,225,000, as shown on line 5, page 2 of Exhibit No. 10, Schedule 2. The resulting revenue requirement is shown on line 7 and amounts to $1,921,000, or an increase of 2.72% over pro forma general business and transportation revenues.

V. 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-10-01 and AVU-G-10-01?

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

VI. DEFERRED ACCOUNTING REQUEST FOR THE VARIABILITY IN GENERATING PLANT OPERATION AND MAINTENANCE COSTS

Q. Would you please explain the Company's request for deferred accounting associated with the variability in operation and maintenance costs related to its two major thermal generating plants?

A. Yes. The Company is proposing to defer changes in operation and maintenance costs related to its Coyote

Springs 2 (CS2) natural gas-fired generating plant located near Boardman, Oregon, and its 15 percent ownership share of the Colstrip 3 & 4 coal-fired generating plants located in southeastern Montana. Both the Coyote Springs 2 and Colstrip 3 & 4 plants have schedules where major maintenance is to be performed.

The Company is requesting deferred accounting treatment for these two plants specifically (CS2 and Colstrip) because major maintenance is scheduled every third or fourth year, providing large cost swings for these plants in any given year. This fluctuation in maintenance costs is typically not experienced by the Company's other hydro operating facilities or its Kettle Falls generating plant. For example, each unit at Colstrip has a regularly scheduled overhaul every third year. Since we have two units, this means that two out of every three years will have a scheduled major maintenance outage and its associated costs. Whereas the maintenance interval at Coyote Springs 2 is based on hours of operation. We schedule these major outages in accordance with Original Equipment Manufacturer (OEM) guidelines on wear patterns and cycles for key plant equipment.

Therefore, depending on when the outages for each of these plants fall, we can have as much as two scheduled outages in one year or no scheduled outages, providing the potential for large cost fluctuations on a year-to-year basis. Unexpected outages also cause costs to fluctuate as more costs are incurred to repair the plant. However, in an unexpected outage situation, we may on a case-by-case basis have instances where operation and maintenance expense may actually be lower than authorized, as a portion of the repair costs are likely to be capitalized. The use of deferred accounting would smooth out these costs.

Q. How would the proposed deferred accounting work?

A. The Company would compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip 3 & 4 plants to the amount of expenses authorized for recovery in its last general rate case, and defer the difference from that currently authorized. The deferral would occur annually, with a carrying charge, with deferred costs being amortized over a three-year period, beginning in January of the year following the period costs are deferred. The comparison of actual to authorized costs would use the combined costs from the Coyote Springs 2 and Colstrip 3 & 4 plants. The reason for combining costs is to allow for the possibility that there might be lower than authorized costs from one plant that would offset higher than authorized costs from another plant in a given year.

Q. Why are you including both operation and maintenance expenses rather than just maintenance expense?

A. Operation and maintenance expenses are combined to take into account that during times of major maintenance, operation expense will decline, while maintenance expense will increase. By including both operation and maintenance expense, the decline in operation expense may partially offset the increase in maintenance expense.

Q. Would you please explain how the Company proposes to account for the deferred operations and maintenance expenses?

A. Pursuant to *Idaho Code* § 61-524, the Company requests to defer the operations and maintenance expenses referenced above in Account 182.3 - Other Regulatory Assets. The deferrals would be allocated to the Idaho and Washington jurisdictions based on the Production / Transmission allocation percentages in place at the time the deferrals are made, and placed in separate Idaho and Washington sub-accounts. Account 182.3 - Other Regulatory Assets would be debited, and Account 407.4 - Regulatory Credits would be credited as the deferrals are recorded. Amortization would be recorded by debiting Account 407.3 - Regulatory Debits, and crediting Account 182.3 - Other Regulatory Assets. Interest would accrue on the Idaho share of the deferrals, net of deferred federal income tax, at the Company's weighted cost of debt, updated and compounded semi-annually.

Q. What is the amount of actual, non-fuel, operations and maintenance costs for the Coyote Springs 2 and Colstrip 3 & 4 plants included in the 2010 test period?

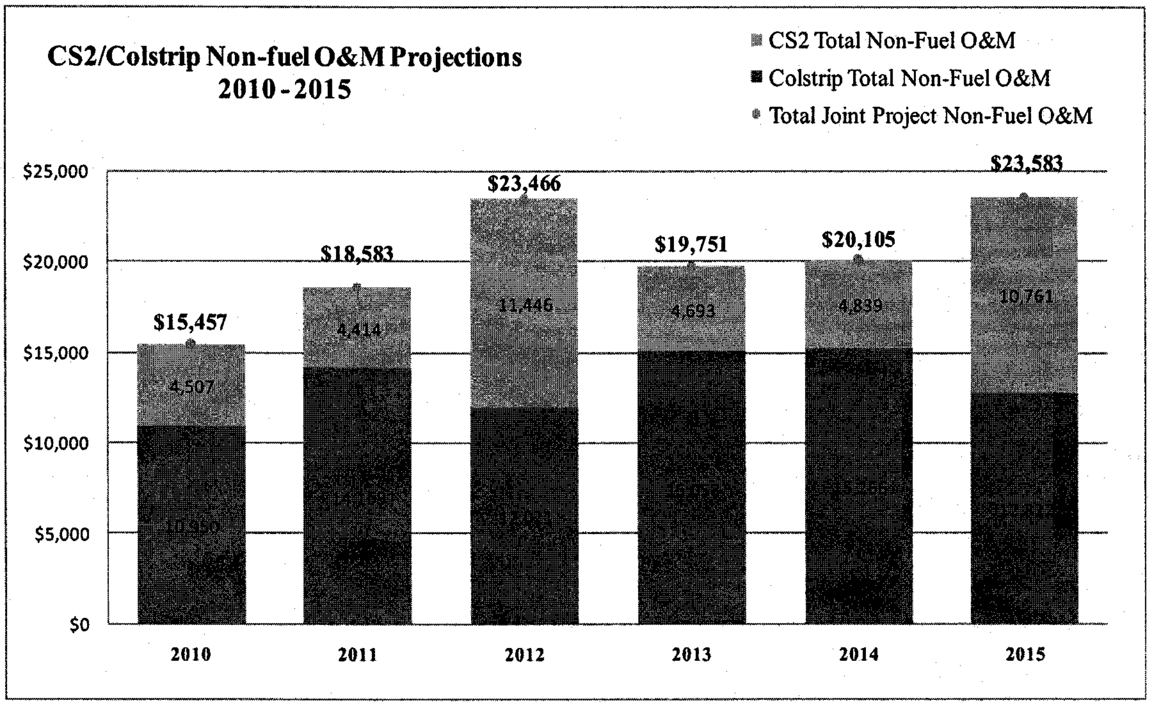
A. The system amount of actual, non-fuel, operations and maintenance costs for the 2010 test period for the indicated plants is shown below (millions):

Coyote Springs 2	$ 4.5
Colstrip 3 & 4	$11.0
Total (System)	$15.5

Q. What is the forecast of operation and maintenance costs for the Coyote Springs 2 and Colstrip 3 &4 plants?

A. The following Illustration No. 2 shows the system forecast of non-fuel, operations and maintenance costs for the plants separately, and in total, for the five-year period of 2011 through 2015, as well as the actual costs for the 2010 test period. The system forecast shows major maintenance occurring for Coyote Springs 2 in 2012 and 2015, and for Colstrip 3 & 4 occurring in 2013 and 2014.

Illustration No. 2 (System)



Q. What amount of non-fuel, operation and maintenance expense for Coyote Springs 2 and Colstrip 3 & 4 should be included for recovery in a general rate case?

A. The amount of expense to be included for recovery in a general rate case should be the actual O&M expense recorded in the test period, excluding any amount deferred during the test period, plus the amortization of previously deferred costs in the test period.

Q. Why is it not appropriate to use a historic average of operation and maintenance costs for the thermal plants to determine the amount of expense to be included for recovery in a general rate case?

A. The previous bar chart illustrates the variability in operations and maintenance costs for the thermal plants, and the upward trend in costs. The Company expects these costs to rise as the plants age, and as parts and labor become more expensive. Use of a historic average would likely understate the level of costs that the Company will experience in the future. A historic average can also be impacted by limiting, or expanding, the number of years used in computing the average, depending on the annual amounts of costs that have previously been incurred.

Q. Has the Company included or pro formed any additional O&M expense in this case for 2012 above that included in the 2010 test period?

A. No. Although the Company is anticipating incurring this additional expense during the 2012 rate period, this additional expense has not been included in the Company's case.

Q. Why did the Company choose a three-year amortization period?

A. A three-year amortization period was chosen as a reasonable recovery period since spikes in operations and maintenance expenses can occur every three to five years. For example, the Company's Colstrip units have outages two out of three years, however, the CS2 unit, based on hours typically dictates an outage every forth year. The three-year amortization period would generally fully amortize the costs of major maintenance of a unit, prior to the major maintenance occurring again for the same unit.

VII. OTHER

Q. Please address the filing requirements as required in Order No. 29962.

A. In Order No. 29962 (Case Nos. AVU-E-05-9 and AVU-G-05-3), the Commission directed the Company to record regulatory assets or liabilities associated with the implementation of Statement of Financial Accounting Standards (SFAS) 143. As a result of the Order, the Company is required to file annually, and as part of any rate case filing, all journal entries made under the requirements of SFAS 143. These ARO transactions have been removed from the test year (twelve months ended December 31, 2010) Results of Operations and have no impact on the Company's earnings or rate request in this case. The journal entries for the calendar year 2010 have been filed with the Commission in our annual compliance filing.

Q. Is the Company requesting a change in the annual filing requirement that is required by Order No. 29962?

A. Yes. The Company requests that the Commission eliminate the annual filing requirement that is required by Order No. 29962. Avista has filed the journal entries in compliance filings for the past four years. The journal entries have been routine in nature, including recording accretion of the ARO liabilities and depreciation of the ARO assets. Because of this, and the fact that all ARO transactions are removed from Idaho results of operation, the Company is requesting that filing obligations under the

Commission's prior order be removed. The Company will maintain the same records regarding the ARO transactions and would have them available to Staff and any other party upon request.

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

A. Yes, it does.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-11-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-11-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 10
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	ELIZABETH M. ANDREWS
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO PRO FORMA RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	DESCRIPTION	Actual Per Results Report	Total Adjustments	Pro Forma Total	Proposed Revenues & Related Exp	Pro Forma Proposed Total
	a	b	c	d	e	f
	REVENUES					
1	Total General Business	$249,722	$ (3,553)	$246,169	$9,009	$255,178
2	Interdepartmental Sales	210		210		210
3	Sales for Resale	89,301	(74,555)	14,746		14,746
4	Total Sales of Electricity	339,233	(78,108)	261,125	9,009	270,134
5	Other Revenue	44,982	(39,125)	5,857		5,857
6	Total Electric Revenue	384,215	(117,233)	266,982	9,009	275,991
	EXPENSES					
	Production and Transmission					
7	Operating Expenses	124,933	(50,130)	74,803		74,803
8	Purchased Power	108,732	(58,813)	49,919		49,919
9	Depreciation and Amortization	7,293	8,052	15,345		15,345
10	Taxes	5,264	668	5,932		5,932
11	Total Production & Transmission	246,222	(100,223)	145,999	0	145,999
	Distribution					
12	Operating Expenses	8,746	1,495	10,241		10,241
13	Depreciation	10,295	1,640	11,935		11,935
14	Taxes	5,468	(2,422)	3,046	135	3,181
15	Total Distribution	24,509	713	25,222	135	25,357
16	Customer Accounting	3,920	(198)	3,722	15	3,737
17	Customer Service & Information	8,116	(7,585)	531		531
18	Sales Expenses	17	1	18		18
	Administrative & General					
19	Operating Expenses	23,695	(1,780)	21,915	18	21,933
20	Depreciation	5,206	1,219	6,425		6,425
21	Taxes		241	241		241
22	Total Admin. & General	28,901	(320)	28,581	18	28,599
23	Total Electric Expenses	311,685	(107,612)	204,073	168	204,241
24	OPERATING INCOME BEFORE FIT	72,530	(9,621)	62,909	8,841	71,750
	FEDERAL INCOME TAX					
25	Current Accrual	11,355	(4,336)	7,019	3,094	10,113
26	Deferred Income Taxes	7,176	1,307	8,483		8,483
27	Amortized Investment Tax Credit	(45)	(34)	(79)		(79)
	SETTLEMENT EXCHANGE POWER					
28	NET OPERATING INCOME	$54,044	($6,558)	$47,486	$5,747	$53,233
	RATE BASE					
	PLANT IN SERVICE					
29	Intangible	$41,399	$9,360	$50,759		$50,759
30	Production	371,892	21,117	393,009		393,009
31	Transmission	167,091	16,973	184,064		184,064
32	Distribution	406,221	33,403	439,624		439,624
33	General	67,570	12,577	80,147		80,147
34	Total Plant in Service	1,054,173	93,430	1,147,603	0	1,147,603
35	ACCUMULATED DEPRECIATION	350,181	57,393	407,574		407,574
36	ACCUM. PROVISION FOR AMORTIZATION	6,399		6,399		6,399
37	Total Accum. Depreciation & Amort.	356,580	57,393	413,973	0	413,973
38	GAIN ON SALE OF BUILDING					
39	WORKING CAPITAL		7,710	7,710		7,710
40	DEFERRED TAXES		(114,339)	(114,339)		(114,339)
41	TOTAL RATE BASE	$697,593	($78,302)	$627,001	$0	$627,001
42	RATE OF RETURN	7.75%		7.57%		8.49%

↑
(9.1% including <-$114,339> DFIT on Plant Rate base, see also page 5 of 11, Schedule 1)

AVISTA UTILITIES
Calculation of General Revenue Requirement
IDAHO - Electric System
TWELVE MONTHS ENDED DECEMBER 31, 2010

Line No.	Description	(000's of Dollars)
1	Pro Forma Rate Base	$627,001
2	Proposed Rate of Return	8.49%
3	Net Operating Income Requirement	$53,232
4	Pro Forma Net Operating Income	$47,486
5	Net Operating Income Deficiency	$5,746
6	Conversion Factor	0.63778
7	Revenue Requirement	$9,009
8	Total General Business Revenues	$246,379
9	Percentage Revenue Increase	3.66%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Idaho - Electric
Pro Forma Cost of Capital
(000's OF DOLLARS)

	Black Box-Current Approved Cost of Capital			
Idaho Component	**Capital Structure**	**Cost**	**Weighted Cost**	**Excludes STD**
Long-Term Debt	49.85%	6.050%	3.02%	ID Wtd Debt 3.02%
Pref Trust	0.00%	0.000%	0.00%	
Common	50.15%	10.90%	5.47%	
Total	100.00%		8.49%	

AVISTA UTILITIES
CALCULATION OF CONVERSION FACTOR: IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2010

Revenue:		*1.000000*
Expense:		
Uncollectibles (1)		***0.001665***
Commission Fees (2)		***0.002039***
Idaho Income Tax (3)		***0.015093***
Total Expense		0.018797
Net Operating Income Before FIT		*0.981203*
Federal Incon	0.35	*0.343421*
REVENUE CONVERSION FACTOR		0.63778

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Results Report	Deferred FIT Rate Base	Deferred Gain on Office Building	Colstrip 3 AFUDC Elimination	Colstrip Common AFUDC	Kettle Falls & Boulder Park Disallow.	Customer Advances
	a	b	c	d	e	f	g	h
	REVENUES							
1	Total General Business	$249,722						
2	Interdepartmental Sales	210						
3	Sales for Resale	89,301						
4	Total Sales of Electricity	339,233	0	0	0	0	0	0
5	Other Revenue	44,982						
6	Total Electric Revenue	384,215	0	0	0	0	0	0
	EXPENSES							
	Production and Transmission							
7	Operating Expenses	124,933						
8	Purchased Power	108,732						
9	Depreciation and Amortizatic	7,293			191			
10	Taxes	5,264						
11	Total Production & T	246,222	0	0	191	0	0	0
	Distribution							
12	Operating Expenses	8,746						
13	Depreciation	10,295						
14	Taxes	5,468		1				
15	Total Distribution	24,509	0	1	0	0	0	0
16	Customer Accounting	3,920						
17	Customer Service & Information	8,116						
18	Sales Expenses	17						
	Administrative & General							
19	Operating Expenses	23,695		(66)				
20	Depreciation	5,206						
21	Taxes							
22	Total Admin. & Gen	28,901	0	(66)	0	0	0	0
23	Total Electric Expenses	311,685	0	(65)	191	0	0	0
24	OPERATING INCOME BEFORE FIT	72,530	0	65	(191)	0	0	0
	FEDERAL INCOME TAX							
25	Current Accrual	11,355		22				
26	Deferred Income Taxes	7,176						
27	Amortized ITC - Noxon	(45)						
28	NET OPERATING INCOME	$54,044	$0	$43	($191)	$0	$0	$0
			OKAY	OKAY	OKAY	OKAY	OKAY	OKAY
	RATE BASE							
	PLANT IN SERVICE							
29	Intangible	$41,399						
30	Production	371,892			7,325	774	(5,609)	
31	Transmission	167,091						
32	Distribution	406,221						(858)
33	General	67,570						
34	Total Plant in Servic	1,054,173	0	0	7,325	774	(5,609)	(858)
35	ACCUMULATED DEPRECIATION	350,181			5,832		(3,119)	
36	ACCUM. PROVISION FOR AMORTIZAT	6,399						
37	Total Accum. Depreciation &	356,580	0	0	5,832	0	(3,119)	0
38	GAIN ON SALE OF BUILDING							
39	WORKING CAPITAL							
40	DEFERRED TAXES		(104,677)				610	
41	TOTAL RATE BASE	$697,593	($104,677)	$0	$1,493	$774	($1,880)	($858)
42	RATE OF RETURN		9.1%					

<--- Actual (Excluding minor additional DFIT included in restating adjustments associated with CDA, Spokane River & Montana deferral adjustments (j) thru (o))

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 20
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Weatherizn and DSM Investment	Restating CDA Settlement	Restating CDA Settlement Deferral	Restating CDA/SRR CDR	Restating Spokane River Deferral	Restating Spokane River PM&E Deferral
	a	i	j	k	l	m	n
	REVENUES						
1	Total General Business						
2	Interdepartmental Sales						
3	Sales for Resale						
4	Total Sales of Electricity	0	0	0	0	0	0
5	Other Revenue						
6	Total Electric Revenue	0	0	0	0	0	0
	EXPENSES						
	Production and Transmission						
7	Operating Expenses				348		
8	Purchased Power						
9	Depreciation and Amortizatic		29	18		3	20
10	Taxes						
11	Total Production & T	0	29	18	348	3	20
	Distribution						
12	Operating Expenses						
13	Depreciation						
14	Taxes	3			(5)		
15	Total Distribution	3	0	0	(5)	0	0
16	Customer Accounting						
17	Customer Service & Information	(229)					
18	Sales Expenses						
	Administrative & General						
19	Operating Expenses						
20	Depreciation						
21	Taxes						
22	Total Admin. & Gen	0	0	0	0	0	0
23	Total Electric Expenses	(226)	29	18	343	3	20
24	OPERATING INCOME BEFORE FIT	226	(29)	(18)	(343)	(3)	(20)
	FEDERAL INCOME TAX						
25	Current Accrual	79	(10)	(6)	(120)	(1)	(7)
26	Deferred Income Taxes						
27	Amortized ITC - Noxon						
28	NET OPERATING INCOME	$147	($19)	($12)	($223)	($2)	($13)
		OKAY	*OKAY*	*OKAY*	*OKAY*	*OKAY*	*OKAY*
	RATE BASE						
	PLANT IN SERVICE						
29	Intangible			$317		$60	$270
30	Production	65					
31	Transmission						
32	Distribution						
33	General						
34	Total Plant in Servic	65	0	317	0	60	270
35	ACCUMULATED DEPRECIATION		487	62	105	12	47
36	ACCUM. PROVISION FOR AMORTIZAT						
37	Total Accum. Depreciation &	0	487	62	105	12	47
38	GAIN ON SALE OF BUILDING						
39	WORKING CAPITAL						
40	DEFERRED TAXES		170	(89)	37	(17)	(78)
41	TOTAL RATE BASE	$65	($317)	$166	($68)	$31	$145
42	RATE OF RETURN						

Exhibit No. 10
Case No. AVU-E-11-01 and AVU-G-11-01
E. Andrews, Avista

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 20
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Restating Montana Lease	Working Capital	Subtotal Actual	Eliminate B & O Taxes	Property Tax	Uncollect. Expense	Regulatory Expense	Injuries and Damages
	a	o	p	-	q	r	s	t	u
	REVENUES								
1	Total General Business			$249,722	$ (3,018)				
2	Interdepartmental Sales			210					
3	Sales for Resale			89,301					
4	Total Sales of Electricity	0	0	339,233	(3,018)	0	0	0	0
5	Other Revenue			44,982					
6	Total Electric Revenue	0	0	384,215	(3,018)	0	0	0	0
	EXPENSES								
	Production and Transmission								
7	Operating Expenses	46		125,327					
8	Purchased Power			108,732					
9	Depreciation and Amortizatic			7,554					
10	Taxes			5,264		297			
11	Total Production & T	46	0	246,877	0	297	0	0	0
	Distribution								
12	Operating Expenses			8,746					
13	Depreciation			10,295					
14	Taxes	(1)		5,466	(3,012)	175	2		9
15	Total Distribution	(1)	0	24,507	(3,012)	175	2	0	9
16	Customer Accounting			3,920			(159)		
17	Customer Service & Information			7,887					
18	Sales Expenses			17					
	Administrative & General								
19	Operating Expenses			23,629				(3)	(619)
20	Depreciation			5,206					
21	Taxes					3			
22	Total Admin. & Gen	0	0	28,835	0	3	0	(3)	(619)
23	Total Electric Expenses	45	0	312,043	(3,012)	475	(157)	(3)	(610)
24	OPERATING INCOME BEFORE FIT	(45)	0	72,172	(6)	(475)	157	3	610
	FEDERAL INCOME TAX								
25	Current Accrual	(16)		11,296	(2)	(166)	55	1	214
26	Deferred Income Taxes			7,176					
27	Amortized ITC - Noxon			(45)					
28	NET OPERATING INCOME	($29)	$0	$53,745	($4)	($309)	$102	$2	$396
		OKAY	OKAY		OKAY	OKAY	OKAY	OKAY	OKAY
	RATE BASE								
	PLANT IN SERVICE								
29	Intangible			$42,046					
30	Production	1,533		375,980					
31	Transmission			167,091					
32	Distribution			405,363					
33	General			67,570					
34	Total Plant in Servic	1,533	0	1,058,050	0	0	0	0	0
35	ACCUMULATED DEPRECIATION			353,607					
36	ACCUM. PROVISION FOR AMORTIZAT			6,399					
37	Total Accum. Depreciation &	0	0	360,006	0	0	0	0	0
38	GAIN ON SALE OF BUILDING								
39	WORKING CAPITAL		7,710	7,710					
40	DEFERRED TAXES	(537)		(104,581)					
41	TOTAL RATE BASE	$996	$7,710	$601,173	$0	$0	$0	$0	$0
42	RATE OF RETURN								

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 20
(000'S OF DOLLARS)

Line No.	DESCRIPTION	FIT	Idaho PCA	Nez Perce Settlement Adjustment	Eliminate A/R Expenses	Revenue Normalization Adjustment	Misc A&G Restating Adjs
	a	v	w	x	y	z	aa
	REVENUES						
1	Total General Business		$ (13,062)			$16,751	
2	Interdepartmental Sales						
3	Sales for Resale						
4	Total Sales of Electricity	0	(13,062)	0	0	16,751	0
5	Other Revenue						
6	Total Electric Revenue	0	(13,062)	0	0	16,751	0
	EXPENSES						
	Production and Transmission						
7	Operating Expenses		(3,227)	(17)		(371)	(1)
8	Purchased Power						
9	Depreciation and Amortizatic					6,429	
10	Taxes						
11	Total Production & T	0	(3,227)	(17)	0	6,058	(1)
	Distribution						
12	Operating Expenses						(1)
13	Depreciation						
14	Taxes				$2	271	14
15	Total Distribution	0	0	0	2	271	13
16	Customer Accounting		(33)		$ (124)	29	3
17	Customer Service & Information					(7,339)	(28)
18	Sales Expenses						
	Administrative & General						
19	Operating Expenses		(33)			34	(919)
20	Depreciation						
21	Taxes						
22	Total Admin. & Gen	0	(33)	0	0	34	(919)
23	Total Electric Expenses	0	(3,293)	(17)	(122)	(947)	(932)
24	OPERATING INCOME BEFORE FIT	0	(9,769)	17	122	17,698	932
	FEDERAL INCOME TAX						
25	Current Accrual	(279)	(4,549)	6	$43	6,194	326
26	Deferred Income Taxes	210	1,195				
27	Amortized ITC - Noxon	(8)					
28	NET OPERATING INCOME	$77	($6,415)	$11	$79	$11,504	$606
		OKAY	OKAY	OKAY	OKAY	OKAY	OKAY
	RATE BASE						
	PLANT IN SERVICE						
29	Intangible						
30	Production						
31	Transmission						
32	Distribution						
33	General						
34	Total Plant in Servic	0	0	0	0	0	0
35	ACCUMULATED DEPRECIATION						
36	ACCUM. PROVISION FOR AMORTIZAT						
37	Total Accum. Depreciation &	0	0	0	0	0	0
38	GAIN ON SALE OF BUILDING						
39	WORKING CAPITAL						
40	DEFERRED TAXES						
41	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0
42	RATE OF RETURN						

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 20
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Restating Incentive Adj	Restating CS2 Levelized Adj	Removal Colstrip Stlmnt Exp	Removal CCX Revenue	O&M Savings	Restate Debt Interest	Restated TOTAL
	a	ab	ac	ad	ae	af	ag	-
	REVENUES							
1	Total General Business							$250,393
2	Interdepartmental Sales							210
3	Sales for Resale							89,301
4	Total Sales of Electricity	0	0	0	0	0	0	339,904
5	Other Revenue							44,982
6	Total Electric Revenue	0	0	0	0	0	0	384,886
	EXPENSES							
	Production and Transmission							
7	Operating Expenses			(230)		(99)		121,382
8	Purchased Power							108,732
9	Depreciation and Amortizatic		280		342			14,605
10	Taxes							5,561
11	Total Production & T	0	280	(230)	342	(99)	0	250,280
	Distribution							
12	Operating Expenses					(35)		8,710
13	Depreciation							10,295
14	Taxes	15		3	(5)	2		2,942
15	Total Distribution	15	0	3	(5)	(33)	0	21,947
16	Customer Accounting							3,636
17	Customer Service & Information							520
18	Sales Expenses							17
	Administrative & General							
19	Operating Expenses	(986)				(23)		21,080
20	Depreciation							5,206
21	Taxes							3
22	Total Admin. & Gen	(986)	0	0	0	(23)	0	26,289
23	Total Electric Expenses	(971)	280	(227)	337	(155)	0	302,689
24	OPERATING INCOME BEFORE FIT	971	(280)	227	(337)	155	0	82,197
	FEDERAL INCOME TAX							
25	Current Accrual	340		79	(118)	54	276	13,770
26	Deferred Income Taxes		(98)					8,483
27	Amortized ITC - Noxon							(53)
28	NET OPERATING INCOME	$631	($182)	$148	($219)	$101	($276)	$59,997
		OKAY	OKAY	OKAY	OKAY	OKAY	OKAY	
	RATE BASE							
	PLANT IN SERVICE							
29	Intangible							$42,046
30	Production							375,980
31	Transmission							167,091
32	Distribution							405,363
33	General							67,570
34	Total Plant in Servic	0	0	0	0	0	0	1,058,050
35	ACCUMULATED DEPRECIATION							353,607
36	ACCUM. PROVISION FOR AMORTIZAT							6,399
37	Total Accum. Depreciation &	0	0	0	0	0	0	360,006
38	GAIN ON SALE OF BUILDING							
39	WORKING CAPITAL							7,710
40	DEFERRED TAXES							(104,581)
41	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0	$601,173
42	RATE OF RETURN							

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 20
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Power Supply	Pro Forma Energy Efficiency Load Adjustment	Pro Forma Labor Non-Exec	Pro Forma Labor Exec	Pro Forma Transmission Rev/Exp	Pro Forma Capital Add 2010	Pro Forma Capital Add 2011
	a	PF1	PF2	PF3	PF4	PF5	PF6	PF7
	REVENUES							
1	Total General Business		$ (4,224)					
2	Interdepartmental Sales							
3	Sales for Resale	(75,756)	$1,201					
4	Total Sales of Electricity	(75,756)	(3,023)	0	0	0	0	0
5	Other Revenue	(38,770)				(355)		
6	Total Electric Revenue	(114,526)	(3,023)	0	0	(355)	0	0
	EXPENSES							
	Production and Transmission							
7	Operating Expenses	(47,747)		371	2	743		
8	Purchased Power	(57,656)	$ (1,157)					
9	Depreciation and Amortizatic					89	115	328
10	Taxes							224
11	Total Production & T	(105,403)	(1,157)	371	2	832	115	552
	Distribution							
12	Operating Expenses			243				
13	Depreciation						972	534
14	Taxes	(138)	$ (28)	(15)		(18)	(10)	241
15	Total Distribution	(138)	(28)	228	0	(18)	962	775
16	Customer Accounting		$ (7)	91				
17	Customer Service & Information			11				
18	Sales Expenses			1				
	Administrative & General							
19	Operating Expenses		$ (9)	259	14			
20	Depreciation						(433)	1,480
21	Taxes							179
22	Total Admin. & Gen	0	(9)	259	14	0	(433)	1,659
23	Total Electric Expenses	(105,541)	(1,201)	961	16	814	644	2,986
24	OPERATING INCOME BEFORE FIT	(8,985)	(1,822)	(961)	(16)	(1,169)	(644)	(2,986)
	FEDERAL INCOME TAX							
25	Current Accrual	(3,145)	$ (638)	(336)	(6)	(409)	(225)	(1,045)
26	Deferred Income Taxes							
27	Amortized ITC - Noxon							
28	NET OPERATING INCOME	($5,840)	($1,184)	($625)	($10)	($760)	($419)	($1,941)
		OKAY	OKAY	OKAY	OKAY	OKAY	OKAY	OKAY
	RATE BASE							
	PLANT IN SERVICE							
29	Intangible						$1,157	$5,562
30	Production						2,949	5,552
31	Transmission						5,596	9,407
32	Distribution						7,648	19,155
33	General						4,306	6,332
34	Total Plant in Servic	0	0	0	0	0	21,656	46,008
35	ACCUMULATED DEPRECIATION						6,873	30,623
36	ACCUM. PROVISION FOR AMORTIZAT.							
37	Total Accum. Depreciation &	0	0	0	0	0	6,873	30,623
38	GAIN ON SALE OF BUILDING							
39	WORKING CAPITAL							
40	DEFERRED TAXES						(3,140)	(3,807)
41	TOTAL RATE BASE	$0	$0	$0	$0	$0	$11,643	$11,578
42	RATE OF RETURN							

AVISTA UTILITIES
ELECTRIC RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 20
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Capital Add 2012	Pro Forma Noxon Gen 2011 & 2012	Pro Forma Employee Benefits	Pro Forma Insurance	Pro Forma Vegetation Management	Pro Forma TOTAL
	a	PF8	PF9	PF10	PF11	PF12	PFT
	REVENUES						
1	Total General Business						$246,169
2	Interdepartmental Sales						210
3	Sales for Resale						14,746
4	Total Sales of Electricity	0	0	0	0	0	261,125
5	Other Revenue						5,857
6	Total Electric Revenue	0	0	0	0	0	266,982
	EXPENSES						
	Production and Transmission						
7	Operating Expenses			52			74,803
8	Purchased Power						49,919
9	Depreciation and Amortizatic	57	151				15,345
10	Taxes	81	66				5,932
11	Total Production & T	138	217	52	0	0	145,999
	Distribution						
12	Operating Expenses			4		1,284	10,241
13	Depreciation	134					11,935
14	Taxes	103	(3)	(10)	1	(19)	3,046
15	Total Distribution	237	(3)	(6)	1	1,265	25,222
16	Customer Accounting			2			3,722
17	Customer Service & Information						531
18	Sales Expenses						18
	Administrative & General						
19	Operating Expenses			618	(47)		21,915
20	Depreciation	172					6,425
21	Taxes	59					241
22	Total Admin. & Geni	231	0	618	(47)	0	28,581
23	Total Electric Expenses	606	214	666	(46)	1,265	204,073
24	OPERATING INCOME BEFORE FIT	(606)	(214)	(666)	46	(1,265)	62,909
	FEDERAL INCOME TAX						
25	Current Accrual	(212)	(75)	(233)	16	(443)	7,019
26	Deferred Income Taxes						8,483
27	Amortized ITC - Noxon		(26)				(79)
28	NET OPERATING INCOME	($394)	($113)	($433)	$30	($822)	$47,486
		OKAY	OKAY	OKAY	OKAY	OKAY	
	RATE BASE						
	PLANT IN SERVICE						
29	Intangible	$1,994					$50,759
30	Production	3,447	5,081				393,009
31	Transmission	1,970					184,064
32	Distribution	7,458					439,624
33	General	1,939					80,147
34	Total Plant in Servic	16,808	5,081	0	0	0	1,147,603
35	ACCUMULATED DEPRECIATION	16,350	121				407,574
36	ACCUM. PROVISION FOR AMORTIZAT						6,399
37	Total Accum. Depreciation &	16,350	121	0	0	0	413,973
38	GAIN ON SALE OF BUILDING						
39	WORKING CAPITAL						7,710
40	DEFERRED TAXES	(2,501)	(310)				(114,339)
							0
41	TOTAL RATE BASE	($2,043)	$4,650	$0	$0	$0	$627,001
42	RATE OF RETURN						7.57%

AVISTA UTILITIES
GAS RESULTS OF OPERATION
IDAHO PRO FORMA RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	WITH PRESENT RATES: Actual Per Results Report	Total Adjustments	Pro Forma Total	WITH PROPOSED RATES: Proposed Revenues & Related Exp	Pro Forma Proposed Total
	a	b	c	d	e	f
	REVENUES					
1	Total General Business	$62,878	$7,304	$70,182	$1,921	$72,103
2	Total Transportation	454	(122)	332		332
3	Other Revenues	51,440	(51,310)	130		130
4	Total Gas Revenues	114,772	(44,128)	70,644	1,921	72,565
	EXPENSES					
5	Exploration and Development					
	Production					
6	City Gate Purchases	85,383	(43,898)	41,485		41,485
7	Purchased Gas Expense	375	15	390		390
8	Net Nat Gas Storage Trans	(1,561)	1,570	9		9
9	Total Production	84,197	(42,313)	41,884	0	41,884
	Underground Storage					
10	Operating Expenses	167	151	318		318
11	Depreciation	154	28	182		182
12	Taxes	53	29	82		82
13	Total Underground Storage	374	208	582	0	582
	Distribution					
14	Operating Expenses	3,888	417	4,305		4,305
15	Depreciation	3,445	122	3,567		3,567
16	Taxes	1,672	(1,031)	641	29	670
17	Total Distribution	9,005	(492)	8,513	29	8,542
18	Customer Accounting	2,204	(196)	2,008	3	2,011
19	Customer Service & Information	3,172	(2,799)	373		373
20	Sales Expenses	7	0	7		7
	Administrative & General					
21	Operating Expenses	5,400	(366)	5,034	4	5,038
22	Depreciation	1,027	683	1,710		1,710
23	Taxes	11	60	71		71
24	Total Admin. & General	6,438	377	6,815	4	6,819
25	Total Gas Expense	105,397	(45,215)	60,182	36	60,218
26	OPERATING INCOME BEFORE FIT	9,375	1,087	10,462	1,885	12,347
	FEDERAL INCOME TAX					
27	Current Accrual	(2,229)	446	(1,783)	660	(1,123)
28	Deferred FIT	4,699	9	4,708		4,708
29	Amort ITC	(17)	0	(17)		(17)
						0
30	NET OPERATING INCOME	6,922	$632	7,554	$1,225	$8,779
	RATE BASE: PLANT IN SERVICE					
31	Underground Storage	8,839	1,896	10,735		10,735
32	Distribution Plant	148,345	4,376	152,721		152,721
33	General Plant	15,515	4,524	20,039		20,039
34	Total Plant in Service	172,699	10,796	183,495	0	183,495
	ACCUMULATED DEPRECIATION					
35	Underground Storage	3,488	331	3,819		3,819
36	Distribution Plant	48,439	6,535	54,974		54,974
37	General Plant	4,822	2,096	6,918		6,918
38	Total Accum. Depreciation	56,749	8,962	65,711	0	65,711
39	DEFERRED FIT	0	(23,672)	(23,672)		(23,672)
40	GAS INVENTORY	0	7,737	7,737		7,737
41	WORKING CAPITAL	0	1,553	1,553		1,553
42	GAIN ON SALE OF BUILDING	0	0	-		0
43	TOTAL RATE BASE	115,950	($12,548)	103,402	$0	103,402
44	RATE OF RETURN	5.97%		7.31%		8.49%

(7.21% including <-$23,672> DFIT on Plant Rate base, see also page 5 of 9, Schedule 2)

AVISTA UTILITIES
Calculation of General Revenue Requirement
Idaho - Gas
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000's OF DOLLARS)

Line No.	Description	IDAHO
1	Pro Forma Rate Base	$103,402
2	Proposed Rate of Return	8.49%
3	Net Operating Income Requirement	$8,779
4	Pro Forma Net Operating Income	$7,554
5	Net Operating Income Deficiency	$1,225
6	Conversion Factor	0.637780
7	Revenue Requirement	$1,921
8	Total General Business Revenue	$70,514
9	Percentage Revenue Increase	2.72%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Idaho - Gas
Pro Forma Cost of Capital
(000's OF DOLLARS)

Idaho Component	BlackBox-Current approved Cost of Capital Capital Structure	Cost	Weighted Cost	Excludes STD
Long-Term Debt	49.85%	6.050%	3.02%	ID Wtd Debt 3.02%
Pref Trust	0.00%	0.000%	0.00%	
Pref Stock			0.00%	
Common	50.15%	10.90%	5.47%	
Total	100.00%		8.49%	

AVISTA UTILITIES
CALCULATION OF CONVERSION FACTOR: IDAHO GAS
TWELVE MONTHS ENDED DECEMBER 31, 2010

Revenues	1.000000
Expense:	
Uncollectibles (1)	0.001665
Commission Fees (2)	0.002039
Idaho Income Tax (3)	0.015093
Total Expense	0.018797
Net Operating Income Before FIT	0.981203
Federal Inc 35.00%	0.343421
REVENUE CONVERSION FACTOR	**0.63778**

AVISTA UTILITIES
GAS RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Per Results Report	Deferred FIT Rate Base	Deferred Gain on Office Building	Gas Inventory	Weatherization and DSM Investment	Customer Advances
	a	b	c	d	e	f	g
	REVENUES						
1	Total General Business	$62,878					
2	Total Transportation	454					
3	Other Revenues	51,440					
4	Total Gas Revenues	114,772	0	0	0	0	0
	EXPENSES						
5	Exploration and Development	0					
	Production						
6	City Gate Purchases	85,383					
7	Purchased Gas Expense	375					
8	Net Nat Gas Storage Trans	(1,561)					
9	Total Production	84,197	0	0	0	0	0
	Underground Storage						
10	Operating Expenses	167					
11	Depreciation	154					
12	Taxes	53					
13	Total Underground Storage	374	0	0	0	0	0
	Distribution						
14	Operating Expenses	3,888					
15	Depreciation	3,445					
16	Taxes	1,672				2	
17	Total Distribution	9,005	0	0	0	2	0
18	Customer Accounting	2,204		0	0	0	0
19	Customer Service & Information	3,172				(101)	
20	Sales Expenses	7					
	Administrative & General						
21	Operating Expenses	5,400		(21)			
22	Depreciation	1,027					
23	Taxes	11					
24	Total Admin. & General	6,438	0	(21)	0	0	0
25	Total Gas Expense	105,397	0	(21)	0	(99)	0
26	OPERATING INCOME BEFORE FIT	9,375	0	21	0	99	0
	FEDERAL INCOME TAX	0					
27	Current Accrual	(2,229)		7		35	
28	Deferred FIT	4,699					
29	Amort ITC	(17)					
30	NET OPERATING INCOME	$6,922	$0	$14	$0	$64	$0
			OKAY	*OKAY*	*OKAY*	*OKAY*	*OKAY*
	RATE BASE: PLANT IN SERVICE						
31	Underground Storage	8,839					
32	Distribution Plant	148,345					(74)
33	General Plant	15,515					
34	Total Plant in Service	172,699	0	0	0	0	(74)
	ACCUMULATED DEPRECIATION						
35	Underground Storage	3,488					
36	Distribution Plant	48,439					
37	General Plant	4,822					
38	Total Accum. Depreciation	56,749	0	0	0	0	0
39	DEFERRED FIT	0	(19,934)				
40	GAS INVENTORY	0			4,509		
41	WORKING CAPITAL	0					
42	GAIN ON SALE OF BUILDING	0					
43	TOTAL RATE BASE	$115,950	($19,934)	$0	$4,509	$0	($74)
44	RATE OF RETURN		7.2%	<-- actual including DFIT on Plant Rate base			

Exhibit No. 10
Case No. AVU-E-11-01 and AVU-G-11-01
E. Andrews, Avista
Schedule 2, p. 5 of 9

AVISTA UTILITIES
GAS RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Working Capital	Subtotal Actual	Revenue Normalization	Eliminate B & O Taxes	Property Tax	Uncollectible Expense
	a	h	-	i	j	k	l
	REVENUES						
1	Total General Business		$62,878	$8,427	$ (1,123)		
2	Total Transportation		454	(114)	(8)		
3	Other Revenues		51,440	(51,310)			
4	Total Gas Revenues	0	114,772	(42,997)	(1,131)	0	0
	EXPENSES						
5	Exploration and Development		0				
	Production						
6	City Gate Purchases		85,383	(43,898)			
7	Purchased Gas Expense		375	(9)			
8	Net Nat Gas Storage Trans		(1,561)	1,570			
9	Total Production	0	84,197	(42,337)	0	0	0
	Underground Storage						
10	Operating Expenses		167				
11	Depreciation		154				
12	Taxes		53				
13	Total Underground Storage	0	374	0	0	0	0
	Distribution						
14	Operating Expenses		3,888				
15	Depreciation		3,445				
16	Taxes		1,674	28	(1,130)	35	4
17	Total Distribution	0	9,007	28	(1,130)	35	4
18	Customer Accounting		2,204	14	0		(242)
19	Customer Service & Information		3,071	(2,721)			
20	Sales Expenses		7				
	Administrative & General						
21	Operating Expenses		5,379	17			
22	Depreciation		1,027	173			
23	Taxes		11				
24	Total Admin. & General	0	6,417	190	0	0	0
25	Total Gas Expense	0	105,277	(44,826)	(1,130)	35	(238)
26	OPERATING INCOME BEFORE FIT	0	9,495	1,829	(1)	(35)	238
	FEDERAL INCOME TAX		0				
27	Current Accrual		(2,187)	640		(12)	83
28	Deferred FIT		4,699				
29	Amort ITC		(17)				
30	NET OPERATING INCOME	$0	$7,000	$1,189	($1)	($23)	$155
		OKAY		OKAY	OKAY	OKAY	OKAY
	RATE BASE: PLANT IN SERVICE						
31	Underground Storage		8,839				
32	Distribution Plant		148,271				
33	General Plant		15,515				
34	Total Plant in Service	0	172,625	0	0	0	0
	ACCUMULATED DEPRECIATION						
35	Underground Storage		3,488				
36	Distribution Plant		48,439				
37	General Plant		4,822				
38	Total Accum. Depreciation	0	56,749	0	0	0	0
39	DEFERRED FIT		(19,934)				
40	GAS INVENTORY		4,509				
41	WORKING CAPITAL	1,553	1,553				
42	GAIN ON SALE OF BUILDING		0				
43	TOTAL RATE BASE	$1,553	$102,004	$0	$0	$0	$0
44	RATE OF RETURN		6.86%				

AVISTA UTILITIES
GAS RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Regulatory Expense Adjustment	Injuries and Damages	FIT	Eliminate A/R Expenses	Misc. Restating Adjs	Restating Incentive Adj	O&M Savings
	a	m	n	o	p	q	r	s
	REVENUES							
1	Total General Business							
2	Total Transportation							
3	Other Revenues							
4	Total Gas Revenues	0	0	0	0	0	0	0
	EXPENSES							
5	Exploration and Development							
	Production							
6	City Gate Purchases							
7	Purchased Gas Expense					(1)		
8	Net Nat Gas Storage Trans							
9	Total Production	0	0	0	0	(1)	0	0
	Underground Storage							
10	Operating Expenses							
11	Depreciation							
12	Taxes							
13	Total Underground Storage	0	0	0	0	0	0	0
	Distribution							
14	Operating Expenses					(5)		
15	Depreciation							
16	Taxes	1	1			3	4	
17	Total Distribution	1	1	0	0	(2)	4	0
18	Customer Accounting	0			(20)	2		
19	Customer Service & Information					17		
20	Sales Expenses							
	Administrative & General							
21	Operating Expenses	(41)	(48)			(237)	(249)	(6)
22	Depreciation							
23	Taxes							
24	Total Admin. & General	(41)	(48)	0	0	(237)	(249)	(6)
25	Total Gas Expense	(40)	(47)	0	(20)	(221)	(245)	(6)
26	OPERATING INCOME BEFORE FIT	40	47	0	20	221	245	6
	FEDERAL INCOME TAX							
27	Current Accrual	14	16	75	7	77		2
28	Deferred FIT			(77)			86	
29	Amort ITC							
30	NET OPERATING INCOME	$26	$31	$2	$13	$144	$159	$4
		OKAY	OKAY	OKAY	OKAY	OKAY	OKAY	OKAY
	RATE BASE: PLANT IN SERVICE							
31	Underground Storage							
32	Distribution Plant							
33	General Plant							
34	Total Plant in Service	0	0	0	0	0	0	0
	ACCUMULATED DEPRECIATION							
35	Underground Storage							
36	Distribution Plant							
37	General Plant							
38	Total Accum. Depreciation	0	0	0	0	0	0	0
39	DEFERRED FIT							
40	GAS INVENTORY							
41	WORKING CAPITAL							
42	GAIN ON SALE OF BUILDING							
43	TOTAL RATE BASE	$0	$0	$0	$0	$0	$0	$0
44	RATE OF RETURN							

AVISTA UTILITIES
GAS RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Restate Debt Interest	Restated Total	Pro Forma Labor Non-Exec	Pro Forma Labor Exec	Pro Forma Employee Benefits	Pro Forma Insurance	Pro Forma Survey & Replacement
	a	t	-	PF1	PF2	PF3	PF4	PF5
	REVENUES							
1	Total General Business		$70,182					
2	Total Transportation		332					
3	Other Revenues		130					
4	Total Gas Revenues	0	70,644	0	0	0	0	0
	EXPENSES							
5	Exploration and Development		0					
	Production							
6	City Gate Purchases		41,485					
7	Purchased Gas Expense		365	11		14		
8	Net Nat Gas Storage Trans		9					
9	Total Production	0	41,859	11	0	14	0	0
	Underground Storage							
10	Operating Expenses		167					
11	Depreciation		154					
12	Taxes		53					
13	Total Underground Storage	0	374	0	0	0	0	0
	Distribution							
14	Operating Expenses		3,883	120		2		165
15	Depreciation		3,445					
16	Taxes		620	(4)		(3)		(2)
17	Total Distribution	0	7,948	116	0	(1)	0	163
18	Customer Accounting		1,958	49		1		
19	Customer Service & Information		367	6				
20	Sales Expenses		7					
	Administrative & General							
21	Operating Expenses		4,815	56	21	154	(12)	
22	Depreciation		1,200					
23	Taxes		11					
24	Total Admin. & General	0	6,026	56	21	154	(12)	0
25	Total Gas Expense	0	58,539	238	21	168	(12)	163
26	OPERATING INCOME BEFORE FIT	0	12,105	(238)	(21)	(168)	12	(163)
	FEDERAL INCOME TAX							
27	Current Accrual	77	(1,208)	(83)	(7)	(59)	4	(57)
28	Deferred FIT		4,708					
29	Amort ITC		(17)					
30	NET OPERATING INCOME	($77)	$8,622	($155)	($14)	($109)	$8	($106)
		OKAY		OKAY	OKAY	OKAY	OKAY	OKAY
	RATE BASE: PLANT IN SERVICE							
31	Underground Storage		8,839					
32	Distribution Plant		148,271					
33	General Plant		15,515					
34	Total Plant in Service	0	172,625	0	0	0	0	0
	ACCUMULATED DEPRECIATION							
35	Underground Storage		3,488					
36	Distribution Plant		48,439					
37	General Plant		4,822					
38	Total Accum. Depreciation	0	56,749	0	0	0	0	0
39	DEFERRED FIT		(19,934)					
40	GAS INVENTORY		4,509					
41	WORKING CAPITAL		1,553					
42	GAIN ON SALE OF BUILDING		0					
43	TOTAL RATE BASE	$0	$102,004	$0	$0	$0	$0	$0
44	RATE OF RETURN		8.45%					

AVISTA UTILITIES
GAS RESULTS OF OPERATION
IDAHO RESTATED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2010
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Atmospheric Testing	Pro Forma Capital Add 2010	Pro Forma Capital Add 2011	Pro Forma Capital Add 2012	Pro Forma JP Storage	Pro Forma Total
	a	PF6	PF7	PF8	PF9	PF10	-
	REVENUES						
1	Total General Business						$70,182
2	Total Transportation						332
3	Other Revenues						130
4	Total Gas Revenues	0	0	0	0	0	70,644
	EXPENSES						
5	Exploration and Development						0
	Production						
6	City Gate Purchases						41,485
7	Purchased Gas Expense						390
8	Net Nat Gas Storage Trans						9
9	Total Production	0	0	0	0	0	41,884
	Underground Storage						
10	Operating Expenses					151	318
11	Depreciation		(9)	3	2	32	182
12	Taxes			2	1	26	82
13	Total Underground Storage	0	(9)	5	3	209	582
	Distribution						
14	Operating Expenses	$135					4,305
15	Depreciation		78	30	14		3,567
16	Taxes	$ (2)	(2)	13	24	(3)	641
17	Total Distribution	133	76	43	38	(3)	8,513
18	Customer Accounting						2,008
19	Customer Service & Information						373
20	Sales Expenses						7
	Administrative & General						
21	Operating Expenses						5,034
22	Depreciation		93	374	43		1,710
23	Taxes			45	15		71
24	Total Admin. & General	0	93	419	58	0	6,815
25	Total Gas Expense	133	160	467	99	206	60,182
26	OPERATING INCOME BEFORE FIT	(133)	(160)	(467)	(99)	(206)	10,462
	FEDERAL INCOME TAX						0
27	Current Accrual	$ (47)	(56)	(163)	(35)	(72)	(1,783)
28	Deferred FIT						4,708
29	Amort ITC						(17)
30	NET OPERATING INCOME	($86)	($104)	($304)	($64)	($134)	$7,554
		OKAY	OKAY	OKAY	OKAY	OKAY	
	RATE BASE: PLANT IN SERVICE						
31	Underground Storage		$ (34)	$102	$91	$1,737	10,735
32	Distribution Plant		1,361	1,374	1,715		152,721
33	General Plant		532	3,000	992		20,039
34	Total Plant in Service	0	1,859	4,476	2,798	1,737	183,495
	ACCUMULATED DEPRECIATION						
35	Underground Storage		73	147	75	36	3,819
36	Distribution Plant		1,270	3,496	1,769		54,974
37	General Plant		(284)	1,482	898		6,918
38	Total Accum. Depreciation	0	1,059	5,125	2,742	36	65,711
39	DEFERRED FIT		(1,297)	(1,648)	(743)	(50)	(23,672)
40	GAS INVENTORY					3,228	7,737
41	WORKING CAPITAL						1,553
42	GAIN ON SALE OF BUILDING						0
43	TOTAL RATE BASE	$0	($497)	($2,297)	($687)	$4,879	$103,402
44	RATE OF RETURN						7.31%