DAVID J. MEYER
SENIOR VICE PRESIDENT AND GENERAL COUNSEL
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-4361

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-04-01 CASE NO. AVU-G-04-01 DIRECT TESTIMONY OF DON M. FALKNER

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

CONTENTS

Section		Page
I	**Introduction**	1
II	**Combined Revenue Requirement Summary**	3
III	**Electric Section**	3
	Revenue Requirement	12
	Standard Commission Basis Adjustments	13
	Pro Forma Adjustments	21
IV	**Natural Gas Section**	32
	Revenue Requirement	36
	Standard Commission Basis Adjustments	37
	Pro Forma Adjustments	41
V	**Allocation Procedures**	45
VI	**Advanced Meter Reading Accounting Proposal**	45

Exhibit No. 14 – Electric Revenue Requirement and Results of Operations (pgs 1-10)

Exhibit No. 15 – Natural Gas Revenue Requirement and Results of Operations (pgs 1-8)

I. INTRODUCTION

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

A. My name is Don M. Falkner. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed by Avista Corp., doing business as Avista Utilities ("Avista" or "Company") and my current position is Manager of Revenue Requirements in the Department of State and Federal Regulation.

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

A. I graduated from Washington State University in February of 1981 with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. That same year, I sat for and passed the May Certified Public Accountant exam. I joined the Company in June of 1981. I have served in various positions within the sections of the Finance Department, including Power Supply Accounting, Subsidiary Accounting, Budget and Forecasting, Plant Accounting and Corporate Accounting. For the past 12 years, I have served in the Department of State and Federal Regulation. I have also attended several utility accounting and ratemaking courses.

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

A. As Manager of Revenue Requirements, aside from special projects, I am responsible for preparation of normalized revenue requirement and pro forma studies in the various jurisdictions in which the Company provides utility services. My other main responsibilities over the last 5 to 6 years has been acting as the lead rate analyst in the

Company's most recent electric and natural gas general rate filings in Washington, Idaho and Oregon.

Q. Have you previously testified before this Commission?

A. Yes. I testified before this Commission in 1993 in Case No(s). WWP-E-92-5 and WWP-G-92-2 and was the main revenue requirement witness in the Company's 1998 electric general case, WWP-98-E-11.

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. Messrs. Hirschkorn and Johnson were responsible for the preparation of the pro forma revenue adjustment and the pro forma power supply adjustment, respectively. I will cover each of those adjustments briefly while their testimonies will provide more in-depth discussions. While I provided the numerical revenue requirement impact of the pro forma vegetation management and pro forma transmission project adjustment, Mr. Kopczynski will provide additional operational detail and support regarding those adjustments.

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

A. Yes. I am sponsoring Exhibit Nos. 14 and 15, which were prepared under my supervision and direction.

II. COMBINED REVENUE REQUIREMENT SUMMARY

Q. Could you please summarize the results of the Company's pro forma studies 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 rate of return ("ROR") for the Company's Idaho jurisdictional operations are 4.71% and 5.00%, respectively. Both return levels are substantially below the Company's requested rate of return of 9.82%. The incremental revenue requirements necessary to give the Company an opportunity to earn its requested ROR is $35,222,000 for the electric operations and $4,754,000 for the natural gas operations. By itself, the overall electric percentage request is 24.08%, but after taking into account the Company's proposed reduction to the power cost surcharge currently in effect, the overall electric increase is 11.0%, while the overall natural gas increase is 9.2%.

III. ELECTRIC SECTION

CHANGES SINCE 1997 TEST PERIOD

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

A. The test period being used by the Company is the twelve-month period ending December 31, 2002 presented on a pro forma basis.

Q. What is the Company's Rate of Return that was last authorized by this Commission for its electric operations in Idaho?

A. The Company's currently authorized Rate of Return for its Idaho electric operations is 8.98%. That rate comes from Case No. WWP-98-E-11, which became effective August 1, 1999, and utilized a 1997 test year.

Q. Have there been any changes to base electric rates in the Idaho jurisdiction since August 1, 1999?

A. Yes. As part of the Commission's order in Case No. WWP-E-98-11, a revenue neutral cost of service rate shift was implemented one year later at August 1, 2000, with some classes receiving an increase and others receiving a decrease. In October 1989, the Company implemented a Power Cost Adjustment ("PCA") mechanism. There have been several temporary adjustments to overall Idaho electric rates, both increases and decreases, over the years associated with that mechanism. A surcharge is currently in place.

Q. Does the PCA mechanism have any impact on the normalized level of Company earnings for its Idaho jurisdiction?

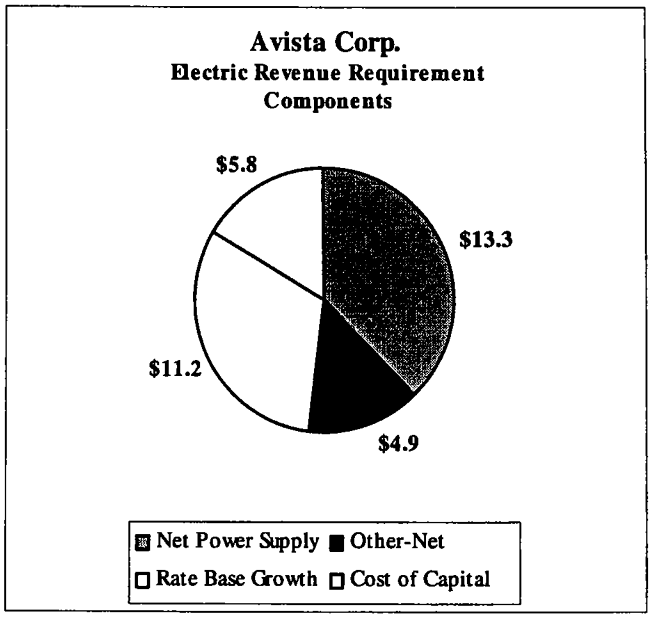
A. No. The PCA mechanism only impacts actual, unadjusted earnings, and those impacts are normalized out, or removed from the pro forma results of operations for the Company's Idaho jurisdiction.

Q. What has been the Company's experienced earnings levels since the rate change associated with Case No. WWP-E-98-11?

A. Outside of one year, the Company has consistently earned below its last authorized level of 8.98%. One of my main responsibilities has been preparation of a jurisdictional electric report that is required in Washington. The Company provides a copy of this report based on its Idaho jurisdiction results to the Idaho Commission Staff. These reports are prepared on a "Commission Basis." Commission Basis means that rate base includes standard rate base components that have historically been accepted by the Commission for ratemaking. Additionally, the Company's booked results of operations are adjusted to a ratemaking basis by normalizing weather impacts on revenues and power supply and eliminating out-of-period items, nonrecurring items or any other item that would materially distort the test period's results. The final result is a restated rate of return for the reporting period. A historical review of the Company's filings with the Commission Staff show that the Company's Idaho electric operations have been earning less than its last authorized rate of for 4 out of the last 5 years.

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

A. There are numerous operational factors that have impacted the Company's electric results of operations since the 1997 test year. On page 10 of my Exhibit No. 14, I have made a side-by-side comparison of the Company's authorized test year net operating income and rate base and our 2002 pro forma levels. As you can see on line 27, column (d), Net Operating Income ("NOI") has declined $11.7 million, or 36%, and Total Rate Base has increased $79.7 million, or 22%. During this same time period, average customers have increased 8.4%. At a high summary level, the Company's electric request is made up of the impacts of changes in net operating income components, rate base growth and cost of capital. Respectively, those items represent $18.2 million, $11.2 million and $5.8 million of the requested $35.2 million of additional general business revenues. The primary component of the reduction in net operating income is increased Net Power Supply costs. I will provide additional detail regarding these items later, but the chart below shows this initial comparison:



Q. The decline in net operating income, represented above by Net Power Supply and Other, makes up slightly more than half of the Company's request. What are the main components of the Other segment?

A. Due to the Company's multi-service and multi-state utility operations, breaking out individual components is initially difficult, however, additional analysis shows that other changes contributing to the decline in Idaho electric net operating income, and the need for additional revenues are increases in depreciation expense, production and transmission O&M, pension costs, insurance costs, and to a lesser degree, increases in customer accounting/service/sales costs and administrative and general expense. Also, a decline in customer usage has impacted the level of the Company's request.

Q. You mentioned a decline in use per customer. How has the Company's customer base changed since the 1997 test year?

A. Average customer count for the Company's Idaho electric jurisdiction has increased from approximately 98,260 to 106,535 at the end of 2002, or an 8.42% increase. Page 10, columns (f) through (i) of Exhibit No. 14 show the same 2002 versus 1997 comparisons on a per customer basis.

Q. Was this increase in customer base accompanied by an associated increase in total revenues?

A. Actually, no. Still looking at that page of Exhibit 14, despite a customer increase of over 8%, line 1, percentage difference column (e), for total general business revenues, excluding the large impact of special contract and a different presentation of the Demand Side Revenue tracker, shows that <u>total</u> revenues have actually declined slightly. After taking into account the addition of 8,275 new customers, general business revenues per customer have declined by almost 9%, on a normalized basis. Since base rates have remained constant, this indicates energy usage has declined. Assuming the incremental power supply cost being utilized in this filing, and the current overall revenue per customer at current rates, the lost margin impact of this decline is approximately $2.7 million. This analysis was done on a total customer basis. Mr. Hirschkorn will discuss the decline in use per customer by schedule in more detail.

Q. Please describe the impact of increased net power supply costs?

A. Net power supply costs is the sum of fuel expense and purchased power costs *less* wholesale revenues, or sales for resale. For this comparison, I've again excluded the impact of the special contract impact. Referring back to Exhibit 14, page 10, and focusing on "Difference" column (d), line 7a, the combination of fuel expense for the Company's steam plants and combustion turbine units, shows an increase of $4.9 million, line 8, Purchased Power, shows a decrease of $22.3 million, while line 3, Sales for Resale, declined $30.7 million. The result is a $13.3 million increase in net power supply costs. In other words, a $17.4 million net reduction in fuel and purchased power expense was being completely offset by a $30.7 million reduction in wholesale revenues. The decline in sales for resale is largely driven by the "monetization," or cash discounting of a capacity contract with Portland General Electric. The benefits of that transaction have been returned to Idaho customers through reductions to the Company's Idaho PCA deferral balance. Mr. Johnson will discuss all the components of the Pro Forma Power Supply adjustment in detail,

Q. Could you please identify some of the other categories that have contributed to the Company's filed revenue requirement?

A. Certainly. Depreciation expense, which has largely followed the 25% growth in gross plant-in-service, has increased $4.2 million. Production and Transmission O&M has increased $3.4 million and has been impacted primarily by maintenance contracts associated with the operation of the Coyote Springs 2 ("CS 2") plant, and wheeling cost changes.

We are utilizing a 2002 test year since that is the most recent normalized financial information the Company has provided the Commission, however, new general electric rates resulting from this filing will not go into affect until later in 2004. Accordingly, the

Company included a number of pro forma, or forward looking cost adjustments, to capture some of the measurable cost increases that the Company has experienced since the 2002 test year. Two of those adjustments are cost increases associated with pension costs and insurance costs. Increases in these categories are not unique to Avista. In fact, pension and insurance cost increases are impacting many regulated utilities. I will provide additional detail for each adjustment later in my testimony. However, as it relates to the Idaho electric analysis, pension costs impacted both operation and maintenance ("O&M") and administrative and general ("A&G") expenses by a total of approximately $1.7 million, while liability and insurance costs increased A&G costs by approximately $1.0. Benefit costs are allocated to follow employee labor costs and ultimately impact all functional areas of the Company's operations, whereas insurance costs are accounted for as A&G expense.

Portions of the pension increase is included in the Production and Transmission O&M increase noted earlier, as well as the Distribution O&M increase of $891,000 and the net Customer Accounting/Service/Sales increase of $673,000. Both pension and insurance increases impacted the overall $2.0 increase in A&G operating expenses, half of that being associated with insurance cost changes. Without an adjustment to update tree trimming costs to a sustainable level, Distribution O&M would have actually shown a decrease. Mr. Kopczynski has provided the operational details supporting that adjustment.

Q. Did you perform any analysis on changes on a cost-per-customer basis?

A. Yes. Referring to Exhibit No. 14, page 10, columns (f) through (i) reflect that analysis, with cost-per-customer changes between the 2002 and 1997 test years in dollars per customer (column (h)) and the percentage change in column (i).

Q. What does that analysis show?

A. Average customers increased 8.42% between 1997 and 2002. Virtually all increases in operating expense groups generally considered to be the most controllable by individual utilities, O&M, customer support costs and A&G, were lower than the 8.42% customer increase level. After taking out the impact of the Coyote Springs 2 pro forma adjustment, production/transmission O&M increased 4.55%, while distribution O&M increased 6.91%, net customer support costs increased 3.47% and A&G operational costs went up 3.47%, all on a cost per customer basis, and all lower than the 8.42% increase in average customers. During this time period, the Consumer Price Index rose 12.1%. Reflecting the impacts of needed new generation and transmission plant investments, depreciation costs for production/transmission and distribution categories increased 13.53% and 11.32%, respectively.

Q. How did you determine the revenue requirement associated with the increase in rate base?

A. Again referring to my Exhibit No. 14, page 10, and looking at line 39, column (d), you can see that Total Rate Base increased $79,661,000 between the two test periods. This net figure is the gross plant increase less the increase in accumulated depreciation and deferred income taxes. By reducing the rate base used in the overall revenue requirement calculation by $79,661,000, and utilizing the currently authorized 8.98% ROR, it showed that the overall revenue requirement was higher by $11.2 million due to the rate base growth.

Q. Why did you use the currently authorized ROR?

A. By using the currently authorized ROR of 8.98%, I eliminated the impact of the Company's requested ROR level on the rate base related revenue requirement increase.

Q. What were the major components of the $79.7 million increase in Total Rate Base?

A. To continue to meet the energy and reliability needs of our customers, the Company has invested additional amounts in thermal and hydro generating facilities, as well as additional transmission investment, which in total make up approximately $61 million, or 77%, of the increase. Specifically, investments in CS 2 and the two small generation projects, Boulder Park and Kettle Falls Combustion Turbine ("CT"), added approximately $50 million. Necessary upgrades to the Company's Cabinet Gorge hydroelectric project added $2.2 million. All of these figures are on an Idaho's jurisdictional basis. The generating capacity from these projects was included in the Company's pro forma power supply calculation. Transmission upgrades added another $8.8 million to Idaho electric plant. Mr. Robert Lafferty discusses the need and reasonableness of the new generation, while Mr. Kopczynski addresses the transmission upgrades. Later in my testimony, I will address the detail behind the normalizing and pro forma net operating income and rate base impact of these adjustments.

<u>REVENUE REQUIREMENT</u>

Q. Would you please explain what is shown in Exhibit No. 14?

A. Exhibit No. 14 shows actual and pro forma electric operating results and rate base for the test period for the State of Idaho. Column (b), page 1 of this Exhibit shows 12-

months ended December 2002 operating results and components of the average-of-monthly-average rate base as recorded; 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 an opportunity to earn a 9.82% rate of return. Column (f) reflects pro forma electric operating results with the requested increase of $35,222,000.

Q. Would you please explain page 2 of Exhibit No. 14?

A. Yes. Page 2 shows the calculation of the $35,222,000 revenue requirement at the requested 9.82% rate of return.

Q. Would you now please explain page 3 of Exhibit No. 14?

A. Yes. Page 3 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 4 through 9 of your Exhibit No. 14, would you please explain what those pages show?

A. Yes. Page 4 begins with actual operating results and rate base for the test period in column (b). Individual normalizing adjustments that are standard components of our annual reporting to the Commissions begin in column (c) on page 4 and continue through column (x) on page 7. Individual pro forma and additional normalizing adjustments begin in column (y) on page 7 and continue through column (ai) on page 9. These adjustments are either refined calculations of adjustments that are usually included as components of our annual reporting, e.g. the Power Supply adjustment, or adjustments that are unique to this general rate filing, e.g. the Pro Forma Insurance or Pro Forma Vegetation Management adjustment. Column (aj) is the final pro forma operating results and rate base for the test period.

<u>STANDARD COMMISSION BASIS ADJUSTMENTS</u>

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

A. Yes. The first adjustment, column (c) on page 4, 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. The effect on Idaho rate base is a reduction of $60,998,000.

Column (d), **Deferred Gain on Office Building**, reflects the rate base reduction for Idaho's portion of the net of tax, unamortized gain on the sale of the Company's general office facility. The facility was sold in December 1986 and leased back by the Company. The effect on Idaho rate base is a reduction of $406,000.

Column (e), **Colstrip 3 AFUDC Elimination**, is a reallocation of rate base and depreciation expense between jurisdictions. In Cause Nos. U-81-15 and U-82-10, the Washington Utilities and Transportation Commission ("WUTC") allowed the Company a return on a portion of Colstrip Unit 3 construction work in progress ("CWIP"). A much smaller amount of Colstrip Unit 3 CWIP was allowed in rate base in Case U-1008-144 by this Commission. The Company eliminated the AFUDC associated with the portion of CWIP allowed in rate base in each jurisdiction. Since production facilities are allocated on the Production/Transmission formula, the allocation of AFUDC is reversed and a direct assignment is made. These amounts are a component of actual results of operations. The effect on Idaho net operating income is a decrease of $218,000. The effect of the reallocation on Idaho rate base is an increase of $3,143,000.

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 the WUTC and this Commission 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 the WUTC and this Commission. 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. These amounts are a component of the actual results of operations. The effect on Idaho rate base is an increase of $1,313,000.

The adjustment in column (g), **Kettle Falls Disallowance**, decreases rate base. The amounts reflect the Kettle Falls generating plant disallowance ordered by this Commission in Case No. U-1008-185. This Commission disallowed a rate of return on $3,009,445 of investment in Kettle Falls. The disallowed investment and related accumulated depreciation are removed. These amounts are a component of actual results of operations. The effect on Idaho rate base in a decrease of $1,435,000.

Q. Please turn to page 5 and explain the adjustments shown there.

A. Column (h), entitled **MOPS Deferred Costs** increases net operating income. MOPS (More Options for Power Supply) pilot program incremental costs were deferred until the July 1, 2001 where a three-year amortization of the Idaho balance commenced. The balance will be fully amortized in June 2004, so this adjustment removes the impact of the amortization included in actual results of operations. The effect on Idaho net operating income is an increase of $38,000.

Column (i), **Weatherization and DSM Investment**, includes in rate base balances (net of amortization) of weatherization grants, the model conservation program costs and electric demand side management (DSM) program costs upon which AFUCE is no longer being accrued and full amortization was implemented beginning August 1994. These amounts are a component of actual results of operations. The effect on Idaho rate base is an increase of $9,110,000.

Q. Would you please explain how energy efficiency-related expenditures impact the revenue requirement in this case?

A. Yes. The unamortized balance of energy efficiency management investment incurred prior to 1995 is included in the results of operations and becomes a rate base item in the column (i) adjustment just described. DSM expenditures incurred after March 13, 1995 have been and will continue to be offset by revenues from the Company's energy efficiency tariff rider, Schedule 91, and are not included in the revenue requirement.

As the Commission is aware, the Company's tariff rider under Schedule 91 was the first non-bypassable distribution charge in the United States to fund energy efficiency. Approved in Case No. WWP-E-94-12, the tariff rider is a 1.5% surcharge to all rate classes, with the exception of pre-existing special contracts. Mr. Hirschkorn provides additional detail and addresses the prudence of the expenditures under this tariff.

Q. Please continue with your explanation of the adjustments on page 5.

A. The adjustment in column (j), entitled **Customer Advances**, decreases rate base for moneys advanced by customers for line extensions as they will most likely be recorded as contributions in aid of construction at some future time. The effect on Idaho rate base is a decrease of $478,000.

The column marked by a dash, and immediately following column (j), subtotals columns (b) through (j) and represents actual operating results and rate base plus the standard rate base adjustments that are included in Commission Basis reporting, but not generally calculated in the Company's monthly jurisdictional Results of Operations reports.

Column (k), **Revenue Adjustment**, is a 4-fold adjustment taking into account known and measurable changes that include revenue normalization, weather normalization, an unbilled revenue calculation and the pro forma impact of a large special contract. It encompasses correction of rate schedule shifts, repricing for approved tariff changes that will be in place in the pro forma test period that were not in place in the historical test period. In this case the weather normalization led to a minimal increase in weather sensitive electric kWh sales and revenues. Mr. Hirschkorn is sponsoring this adjustment. The effect of this particular adjustment is to increase Idaho net operating income by $10,195,000.

The adjustment in column (l), **Hydro Relicensing Adjustment**, decreases net operating income. This adjustment directly assigns the appropriate protection, mitigation and enhancement expenses to the Washington and Idaho jurisdictions. This is necessary due to differing regulatory treatment in Case No. WWP-E-98-11 and Docket No. UE-991606/UG-991607. These amounts are a component of actual results of operations. The effect on Idaho net operating income is a decrease of $165,000.

Column (m), **Eliminate Franchise Fees**, eliminates the revenues and expenses associated with local franchise fees, which the Company is allowed to pass through to its Idaho customers. The adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. Franchise fees 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 $14,000.

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

A. Column (n), entitled **Property Tax**, restates the 2002 test period accrued levels of property taxes to the actual amounts. The effect of this particular adjustment is to decrease Idaho net operating income by $23,000.

Column (o), **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 $42,000.

Column (p), **Regulatory Expense**, restates booked 2002 regulatory expense to reflect the IPUC assessment rates applied to revenues for the test period and the actual levels of FERC fees paid during the test period. The effect of this adjustment is to decrease Idaho net operating income by $10,000.

Column (q), **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. As a result of the WUTC's Order in Docket No. U-88-2380-T, the Company changed to the reserve method of accounting for injuries and damages not covered by insurance for both its electric and gas systems. This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11. The effect of this adjustment is to increase Idaho net operating income by $33,000.

Column (r), **FIT**, is required to reflect the appropriate level of federal income tax expense for the test period. This adjustment removes the effect of certain Schedule M items, matches the jurisdictional allocation of other Schedule M items to related Results of Operations allocations and eliminates any prior period income tax expense. 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 $1,551,000.

Column (s), **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. Malquist, and applied to Idaho's pro forma level of rate base, 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 $3,184,000.

Column (t), **Idaho PCA**, removes the effects of the financial accounting for the PCA. The PCA normalizes and defers certain power supply costs on an ongoing basis between general rate filings. When the deferral balance reaches a certain trigger level, the balance is either returned (refunded) or charged (surcharged) to customers through a special temporary tariff. Revenue adjustments due to the special tariff 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 (k) and column (ab), respectively. The effect of this adjustment is to decrease Idaho net operating income by $8,580,000.

Q. Please turn to the next page and continue with your explanation of the adjustments on page 7.

A. Column (u), entitled **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/UG-991607. The effect of this adjustment is to increase Idaho net operating income by $16,000.

Column (v), **Remove Misc Tariffs Adjustments**, eliminates the revenues and expenses associated with three miscellaneous tariffs where the Company is allowed to pass through to its Idaho customers certain regulatory credits and charges. Specifically, Schedule 65-Centralia Gain, Schedule 59-Residential Exchange and Schedule 91-DSM Tariff Rider. The adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. These separate schedules are not part of this proceeding. The effect of this adjustment is to increase Idaho net operating income by $412,000.

Column (w), **PGE Monetization Amortization**, eliminates the PGE monetization amortization recorded during the test period. The benefits of the PGE Monetization, both the normal amortization, as well as the accelerated amortization credited to the Idaho PCA Deferrals, were completely returned to customers as of December 31, 2002. The effect of this adjustment is to decrease Idaho net operating income by $1,877,000.

Column (x), **Payroll Clearing**, adjusts the payroll loading costs (benefits, payroll taxes and paid time off) expensed through a clearing account during the test period 2002, to the actual payroll loading costs for the test period. The amounts loaded onto labor charges through the estimated payroll loading rates during the 2002 test period produced an expense level lower than the actual amount of employee benefits incurred for the test period. The impact of this true-up to actual decreased Idaho net operating income by $281,000.

<u>PRO FORMA ADJUSTMENTS</u>

Q. Please explain the significance of the 11 columns subsequent to column (x) that begin on page 7 in your Exhibit No. 14.

A. Certainly. The adjustments subsequent to column (x) are pro forma adjustments that recognize the jurisdictional impacts of material items that will impact the pro forma operating period levels for known and measurable changes. They encompass both expense items as well as significant 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 7.

A. Column (y), entitled **Coyote Springs 2**, pro forms in the capital costs and operating costs of the Company's new combustion turbine plant at Boardman, Oregon. Mr. Lafferty explains those costs.

The Coyote Springs 2 combustion turbine became commercially operational on July 1, 2003, and was transferred to plant-in-service at that time. The benefits of the additional generating capacity were incorporated into the pro forma power supply adjustment for a full year. This adjustment pro forms in the impacts of expenses associated with operational and maintenance agreements with the plant operators, as well as the accompanying depreciation expense and property tax increases. The plant-in-service and net rate base amounts reflect a full year of operation. The effect of this adjustment decreases Idaho net operating income by $1,896,000. The effect of the adjustment on Idaho rate base is an increase of $36,965,000.

Column (z), **Small Generation**, pro forms in the capital costs and associated expense of two smaller gas-fired generating plants. Mr. Lafferty provides additional detail regarding those plants. The effect of this adjustment decreases Idaho net operating income by $185,000. The effect of the adjustment on Idaho rate base is an increase of $5,343,000.

The two smaller generation projects, Boulder Park and Kettle Falls CT, became commercially operational in May 2002, and were transferred to plant-in-service at that time. The additional generating capacity from these projects was incorporated into the pro forma power supply adjustment. This adjustment annualizes the impacts of expenses associated with accompanying depreciation expense and property tax increases. The plant-in-service and net rate base amounts reflect a full year of operation. The benefits of the additional generating capacity have been included in the pro forma power supply adjustment for a full year as well.

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

A. Column (aa), entitled **Capital Costs Small Gen Options**, pro forms in the impact of certain capital costs associated with leased turbines that the Commission Staff had recommended to be removed from the PCA deferral balance for the period ending June 30, 2002. The capital costs were removed from the PCA deferral balance and recorded in a separate regulatory asset. These transactions were authorized in Order No. 29130 in Case No. AVU-E-02-06. This case was the Company's submission of a status report and a request for continuation of the current PCA surcharge. Staff later agreed with the Company's recommendation to begin a 5-year amortization period wherein the rate base treatment and recovery of amortization from customers would be addressed in a future regulatory proceeding.

The capital costs required for turbine installation were associated with the Kettle Falls Bi-Fuel lease, the Devil's Gap lease and the Othello turbine lease, and totaled $898,000. These amounts were outlined in Attachment A to the above Order. The lease payments themselves for those three leases were authorized for recovery through the PCA mechanism. As outlined in Mr. Lafferty's testimony discussing the impacts of the 2000/2001 energy crisis, these leased turbines were part of a portfolio of transactions that allowed the Company to avoid entering into very high-cost purchased power arrangements to meet customer loads. The Company submits that the same rationale that supported the prudence of the lease payments should be extended to the associated capital costs of installing the leased turbines. The effect of this adjustment is to decrease Idaho net operating income by $120,000 and to increase Idaho rate base by $539,000.

Column (ab), **Pro Forma Power Supply**, was made under the direction of Mr. Johnson and is explained in detail in his testimony. This adjustment normalizes power supply related revenue and expenses to reflect the twelve-month period September 1, 2004 through August 31, 2005. The effect of the power supply adjustments as outlined in Mr.

Johnson's testimony, which is presented on a system basis, decreases Idaho net operating income by $7,832,000.

Column (ac), **Pro Forma Pension**, updates the 2002 pension expense to the expense being recorded for 2004. Pension expense, on a system basis, was $9.4 million during the 2002 test year and has increased to $14 million for the year 2004. To be conservative and reduce complexity, this adjustment only pro forms in the impact of increased pension costs on labor charged to operating expense accounts, and ignores capitalized labor's impact on rate base. Pension costs that are properly charged to non-utility labor costs have also been excluded from this adjustment. The effect of this adjustment decreases Idaho net operating income by $445,000.

Q. Please describe the Company pension expense?

A. The Company's pension expense, which is determined in accordance with Financial Accounting Standard 87 ("FAS-87"), has increased on a system basis from $2.2 million in 1997 to $14 million in 2004, beginning primarily in 2002. Pension costs during the actual 2002 test year were $9.3 million. The 2004 level of pension expense is actually down somewhat from the 2003 expense of $14.9 million. However, Company projections show the 2004 level of pension expense to continue into the foreseeable future. Pension expense is determined by an outside actuarial firm, in accordance with FAS-87, and the calculation and assumptions are reviewed by the Company's outside accounting firm for reasonableness and comparability to other companies.

As is being experienced by many companies with funded pension plans, the increases are due primarily to the investment performance of plan assets during the major downturn in the equity markets experienced in the last few years. The pension levels noted above are for the Company as a whole. Pension expense, as with other employee benefits, is "loaded" onto actual labor costs, which are then assigned to various functional expense categories and accounts through the payroll process. Historically, approximately 70% of labor goes to O&M expense and 30% to capital. In our adjustment, a detailed analysis of 2002 labor charges was performed to more accurately determine the Idaho O&M percentage of overall labor.

Q. Please describe the Pro Forma Insurance Adjustment also found on page 8?

A. Column (ad), entitled **Pro Forma Insurance**, updates the 2002 insurance expense for general liability, directors and officer ("D&O") liability, property and other policies, to the actual cost of insurance policies that are in effect for 2004. Here again, insurance cost increases is another category that is impacting virtually all utilities in just the past few years. Insurance costs that are properly charged to non-utility operations have been excluded from this adjustment. The effect of this adjustment decreases Idaho net operating income by $649,000.

Q. Please describe some of the causes for the increases in insurance costs?

A. Insurance costs are up significantly as a result of terrorism threats, higher claims, and low investment returns that had previously offset current premiums, as well as the poor financial performance of utility companies since the energy crisis of 2000-2001. Despite these issues, the Company has been able to maintain adequate coverage to protect the Company, its property, employees and customers from adverse financial impact in case adverse circumstances were to occur. A summary of our coverage, limits, and deductibles for major insurance categories follows.

Directors and Officers Liability

D&O coverage is the most significantly changed part of Avista's insurance package. Instead of two layers to provide coverage up to certain historical limits, we have five layers in 2004 for the same limits. The net price is up about 75% overall and the deductible has doubled to $5 million per claim. The prevalence of shareholder claims in the energy industry has hit the industry's two biggest insurers very hard. Their response has been to implement much stricter terms and higher prices. Avista's D&O insurance covers individual directors and officers and extends to the corporation also.

Property

Avista has insured its property with the same firm for several years. This property coverage applies to potential damages to Avista property except joint projects (insured separately along with the other project co-owners) and the utility transmission and distribution assets. Our property insurance was renewed in November 2003 at a lower cost than the expiring policy. We paid significantly higher premiums in each of the two prior years. Avista's historically low claims record helped attract competitive coverage.

General Liability

Avista has two layers of general liability insurance. Avista has not had a general liability claim reimbursed by insurers since the 1990 Firestorm claims. The first layer of coverage was renewed using the same terms as those expiring, but at a much higher premium. The policy was last underwritten and priced in 1998 during very favorable market conditions.

The insurance market has increased significantly since that time. Excess insurance for claims above a certain threshold is the second layer. The overall cost for 2004 coverage is 2.5 times the 2003 premiums, even with the reduced limits.

Q. Please describe the last adjustment found on page 8?

A. Column (ae), entitled **Pro Forma Labor-Non-Exec**, reflects known and measurable changes to test period union and non-union wages and salaries, and excludes executive salaries, which are handled separately in the next adjustment. Test period wages and salaries are restated as if the wage and salary increases for 2002, 2003 and 2004 were in place during the entire pro forma test period. The methodology behind this adjustment is similar to that used in the last Idaho general case, Case No. WWP-E-98-11, except for the separate treatment of executive salaries. The effect of this adjustment on Idaho net operating income is a decrease of $705,000.

Q. Please turn to the final page of Exhibit No. 14, page 9, and continue with your explanation of the adjustments.

A. Column (af), entitled **Pro Forma Labor-Executive**, reflects known and measurable changes to executive compensation. During 2002 and 2003 several executives retired, a new chief financial executive was hired and responsibilities were re-assigned among the executive group. This adjustment sets the current executive group's compensation at pro forma test period levels. Compensation for any member of the 2002 officer group who has since left the Company has been removed from the test year. Compensation costs allocated to 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. The current executive group's salary allocations are set at their expected pro forma test period utility/non-utility percentage splits. The impact of this adjustment on Idaho net operating income is a decrease of $15,000.

Column (ag), **Pro Forma Vegetation Management**, updates the 2002 tree trimming expenditures to a level Company operational personnel have determined is necessary for the proper management of vegetation around both transmission and distribution lines to most effectively ensure reliability levels. Mr. Kopczynski is sponsoring testimony that details the Company's vegetation management plans and the planned expenditure levels. The effect of this adjustment decreases Idaho net operating income by $785,000.

Column (ah), **Pro Forma Transmission Projects**, pro forms in a portion of the capital cost and expenses associated with the West of Hatwai transmission project. West of Hatwai is a multi-year $100 million project being undertaken by the Company to improve reliability across our transmission system. Again, Mr. Kopczynski is sponsoring testimony that details the overall project. The entire project is actually broken down into a number of sub-projects that become used and useful at different times. In this adjustment, three specific projects with estimated system costs and completion dates have been included and are shown in the table below:

Pine Creek 203 kV substation	$6,500,000	December 2003
Beacon – Rathdrum 203 kV line	$18,500,000	May 2004
Beacon – Bell #4 230 kV line	$1,300,000	December 2004

The Pine Creek substation work is actually complete, and because of their near-term completion dates, the other two are projects that the Company submits fall under the definition of "short-term construction work in progress" as outlined in Idaho statute §61-502A. The capital costs have been averaged for a full 12-month 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. The effect of this adjustment decreases Idaho net operating income by $249,000 and increases rate base by $8,849,000.

Column (ai), **Pro Forma Cabinet Gorge Project**, pro forms the capital cost and expenses associated with material upgrades to the Company's Cabinet Gorge hydroelectric generating facility. This $6.5 million project is scheduled to be completed and in-service in March 2004. Here again, the Company submits that this project falls under the definition of short-term construction work in progress. The adjustment was prepared consistent with the methodology used in the previous adjustment. Additionally, the benefit from the increased generating capacity has been incorporated into the pro forma power supply calculation for a full year. Mr. Storro provides additional detail regarding the power supply benefits. The effect of this adjustment decreases Idaho net operating income by $17,000. The effect of the adjustment on Idaho rate base is an increase of $2,232,000.

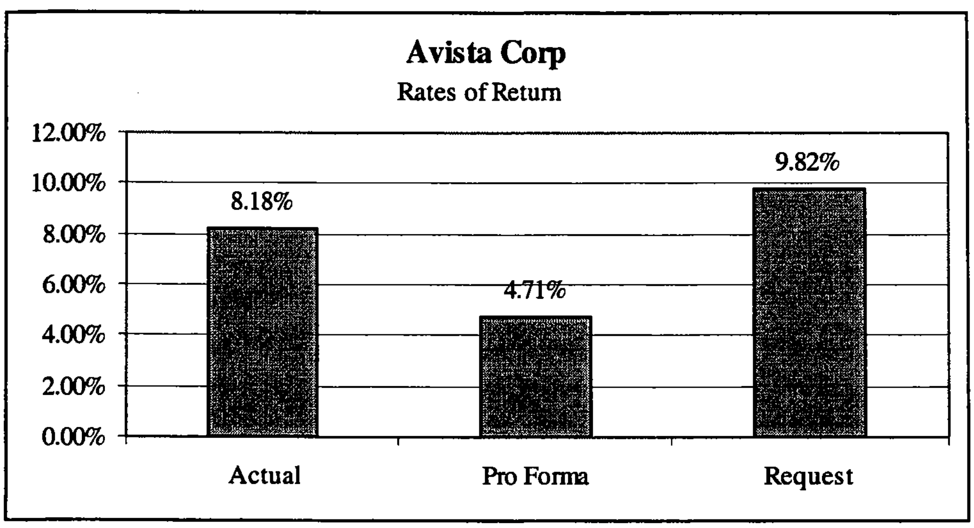
The last column, **Pro Forma Total**, reflects total 2002 pro forma results of operations and rate base consisting of 2002 actual results and the total of all adjustments.

Q. Referring back to page 1, line 40, of Exhibit No. 14, for identification, what was the actual and pro forma electric rates of return realized by the Company during the test period?

A. For the State of Idaho, the actual test period rate of return was 8.18%, somewhat below the last authorized rate of return of 8.98%. The test period pro forma rate of return is 4.71% under present rates. Thus, the Company does not, on a pro forma basis for the test period, realize the 9.82% rate of return requested by the Company in this case.

Q. By way of summary, could you please review the different rates of return that you have presented in your testimony?

A. Yes. Basically, there are three different rates of return discussed previously. The actual ROR earned by the Company during the test period, the Pro Forma ROR determined in my Exhibit No. 14 and the requested ROR. For convenience of comparison, please refer to the following graph:



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 9.82% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $22,516,000, as shown on line 4 of page 2 of Exhibit No. 14. The resulting revenue requirement is shown on line 6 and amounts to $35,222,000, or an increase of 24.08% over pro forma general business revenues, which excludes the PCA surcharge.

IV. NATURAL GAS SECTION

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

A. The test period being used by the Company is the twelve-month period ending December 31, 2002 presented on a pro forma basis.

Q. What is the Company's Rate of Return that was last authorized by this Commission for its gas operations in Idaho?

A. The Company's currently authorized Rate of Return for its Idaho gas operations is 11.02%. That rate comes from Case No. WWP-88-G-5, which became effective October 1, 1989. The filing was based upon a 1987 test year.

Q. Have there been any changes to base gas rates in the Idaho jurisdiction since October 1, 1989?

A. Yes. Reconsideration of the 1988 case resulted in a minor rate adjustment on February 17, 1990 in Case No. WWP-G-89-3. Additionally, a Demand Side Management Tariff Rider ("Tariff Rider") was implemented 1995 through 1997 in which a small surcharge was used to fund energy efficiency improvements. It was reimplemented in 2001. The Company does have Purchased Gas Adjustments ("PGA") in all of its jurisdictions, including Idaho, that periodically adjust customer rates for the commodity and transportation cost associated with procuring natural gas. The PGA rate changes do not impact earnings or general base rates.

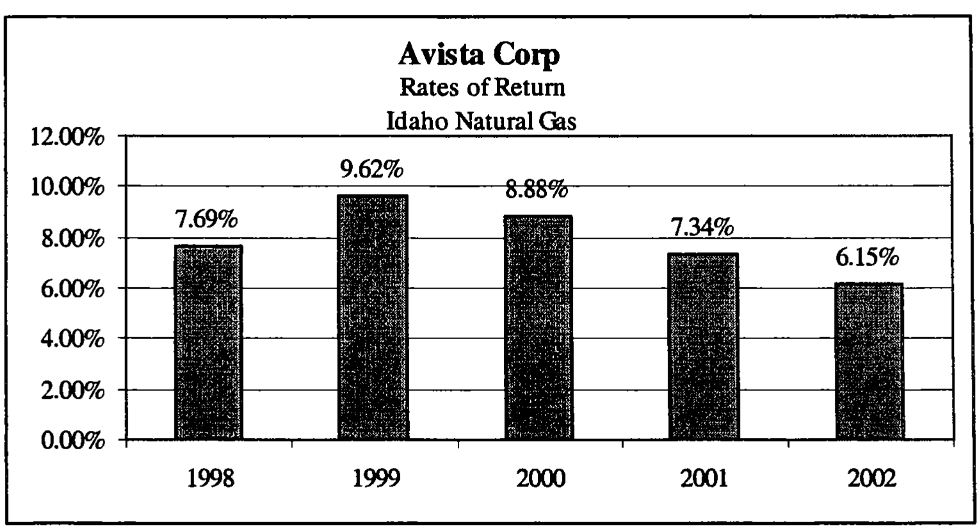
Q. Earlier, in the Electric Section, you performed an analysis of the changes to Idaho electric net operating income and rate base between the last authorized test

year and the Company's current filing. Did you perform a similar analysis for Avista's Idaho natural gas operations?

A. No. As previously noted, current general gas rates are based upon a 1987 test year, 15 years prior to the 2002 test year being utilized in this filing. Test periods so far apart make comparisons difficult and less meaningful. Ultimately, I did perform a similar analysis, but I based it on changes over the last five years, utilizing the Company's 1998 Commission Basis, or normalized, natural gas information, and comparing those results to the 2002 pro forma test year results. The Company provides a copy of the Commission Basis report based on its Idaho jurisdiction results annually to the Commission Staff.

Q. What have been the Company's experienced earnings levels between 1998 and 2002?

A. The ROR for 1998 was 7.69%. In 1999 it rose to 9.62% and then has steadily declined through 2002. For comparison purposes, our official authorized ROR for natural gas operations in Idaho was 11.02%, but it should be noted that our electric authorized ROR was updated to 8.98% in 1999. Below is a graph showing the normalized ROR for each year.



Q. Is there one main issue that contributed to the increase being requested?

A. No. There isn't one single item driving the requested increase. Here again, we need to be reminded that the last test year was 1987, and virtually everything has changed since that time period. As it turns out, there are numerous operational factors that have impacted the Company's natural gas results of operations, even when comparing the current pro forma analysis to 1998 information. When looking at the results of the analysis contained in Exhibit No. 15, page 8, it should be noted that our Idaho natural gas operations is the second smallest operational jurisdiction we operate. Only our 18,000-customer gas system in California is smaller. As a result, many revenue, expense and rate base detail amounts are small, in the hundreds of thousands, making some percentage changes less meaningful due to their sensitivity to dollar changes.

On page 8 of my Exhibit No. 15, I've set up a side-by-side comparison of the Company's 1998 normalized net operating income and rate base with our pro forma levels. As you can see on line 30, column (d), Net Operating Income has declined \$1.2 million or 28% and line 42, shows Total Rate Base has increased \$6.4 million, or 11%. During this same time period, average customers have increased 18.18%. The \$1.2 million reduction in net operating income translates into approximately \$1.9 million of additional revenue requirement and the \$6.4 million increase in rate base adds an additional \$1 million. These are both factors contributing to the requested \$4.8 million of additional general business revenues.

Q. What are some of the other components of the Company's request?

A. Many of the same revenue and expense items that impacted electric operations also impact the natural gas operations, such as depreciation expense, pension costs, insurance costs, and to a lesser degree, increases in customer accounting/service/sales costs and administrative and general expense. A decline in customer usage has also contributed to the level of the Company's request.

Q. How has the Company's customer base changed since the 1998?

A. Average customer count for the Company's Idaho natural gas jurisdiction has increased from approximately 49,712 to 58,752 at the end of 2002, or an 18.18% increase. Columns (f) through (i) on page 8 of my Exhibit No. 15 show the same 2002 versus 1998 comparisons on a per customer basis.

Q. Was this increase in customer base accompanied by an associated increase in total revenues?

A. As can be seen on line 4, total gas revenues increased $13.9 million, but this was mostly due to PGA gas cost increases. Line 4a nets total purchased gas costs against total revenues to estimate gross margin. That figure only increased $585,000 in 5 years, despite an 18.18% increase in customers. More telling is the gross margin per customer decline of $40.07 found by moving over to column (h). Since base rates have remained constant, this indicates energy usage has declined. Mr. Hirschkorn has estimated the impact of the decline in usage by the Company's Schedule 101 customers, residential and small commercial, to be approximately $1.3 million.

Q. Did you perform any analysis on changes on a cost-per-customer basis?

A. Yes I did. Again, referring to page 8 of my Exhibit No. 15, columns (f) through (i) reflect that analysis, with cost-per-customer changes between the 2002 and 1998 years in dollars per customer (column (h)) and the percentage change in column (i).

Q. What does that analysis show?

A. Average customers increased 18.18% between 1998 and 2002. Total expenses by category are relatively small, but lines 25a, Total Operating Expense excluding Gas Purchased Cost, shows that during the last five years that overall cost-per-customer increased 8.13%. During this same time period, the Consumer Price Index rose 10.4%. Line 25b goes a step further and eliminates depreciation and taxes producing just straight operation and maintenance and administrative and general costs. That shows an increase of 5.3%. Line 42, Total Rate Base, actually declined by approximately 6% on a cost-per-customer basis.

REVENUE REQUIREMENT

Q. Would you please explain what is shown in Exhibit No. 15?

A. Exhibit No. 15 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. 15 shows 2002 operating results and components of the average-of-monthly-average rate base as recorded; 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 a 9.82% rate of return. Column (f) reflects pro forma gas operating results with the requested increase of $4,754,000.

Q. Would you please explain page 2 of Exhibit No. 15?

A. Yes. Page 2 shows the calculation of the $4,754,000 revenue requirement at the requested 9.82% rate of return.

Q. Would you now please explain page 3 of Exhibit No. 15?

A. Yes. Page 3 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 4 through 7 of your Exhibit No. 15, would you please explain what those pages show?

A. Yes. Page 4 begins with actual operating results and rate base for the test period in column (b). Individual normalizing adjustments that are standard components of our annual reporting to the Staff begin in column (c) on page 4 and continue through column (o) on page 6. Individual pro forma and additional normalizing adjustments begin in column (p) on page 6 and continue through column (t) on page 7. The final column on page 7 is the total pro forma operating results and rate base for the test period.

<u>STANDARD COMMISSION BASIS ADJUSTMENTS</u>

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

A. Yes. The first adjustment, column (c) on page 4, 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. The effect on Idaho rate base is a reduction of $7,261,000.

Column (d), **Deferred Gain on Office Building**, reflects the rate base reduction for Idaho's portion of the net of tax, unamortized gain on the sale of the Company's general office facility. The facility was sold in December 1986 and leased back by the Company. The effect on Idaho rate base is a reduction of $128,000.

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 and the Plymouth LNG Plant. The effect on Idaho rate base is an increase of $1,572,000.

Column (f), **Weatherization and DSM Investment**, includes in rate base balances (net of amortization) of gas demand side management ("DSM") program costs upon which AFUCE is no longer being accrued and full amortization was implemented beginning August 1994. These amounts are a component of actual results of operations. The effect on Idaho rate base is an increase of $941,000.

Q. Please turn to page 5 and explain the adjustments shown there.

A. The adjustment in column (g), entitled **Customer Advances**, decreases rate base for funds advanced by customers for line extensions, as they will most likely be recorded as contributions in aid of construction at some future time. The effect on Idaho rate base is a decrease of $1,000.

The column marked by a dash, and immediately following column (g), subtotals columns (b) through (g) and represents actual operating results and rate base plus the standard rate base adjustments that are included in Commission Basis reporting, but not generally calculated in the Company's monthly Results of Operations reports.

Column (h), **Eliminate Franchise Fees**, eliminates the revenues and expenses associated with local franchise fees, which the Company is allowed to pass through to its Idaho customers. The adjustment eliminates any timing mismatch that exists between the revenues and expenses by eliminating the revenues and expenses in their entirety. Franchise fees are passed through on a separate schedule, which is not part of this proceeding. The effect of this adjustment is to increase Idaho net operating income by $34,000.

Column (i), **Property Tax**, restates the 2002 test period accrued levels of property taxes to the actual amounts. The effect of this particular adjustment is to decrease Idaho net operating income by $3,000.

Column (j), **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 $73,000.

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

A. Column (k), entitled **Regulatory Expense Adjustment**, restates booked 2002 regulatory expense to reflect the IPUC assessment rates applied to revenues for the test period. The effect of this adjustment is to decrease Idaho net operating income by $4,000.

Column (l), **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. As a result of the WUTC's Order in Docket No. U-88-2380-T, the Company changed to the reserve method of accounting for injuries and damages not covered by insurance for both its electric and gas systems. This methodology was accepted by the Idaho Commission in Case No. WWP-E-98-11. The effect of this adjustment is to increase Idaho net operating income by $53,000.

Column (m), **FIT**, is required to reflect the appropriate level of federal income tax expense for the test period. This adjustment removes the effect of certain Schedule M items, matches the jurisdictional allocation of other Schedule M items to related Results of Operations allocations and eliminates any prior period income tax expense. 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 decrease Idaho net operating income by $71,000.

Column (n), **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. Malquist, and applied to Idaho's pro forma level rate base, 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 $576,000.

Column (o), **Payroll Clearing**, adjusts the payroll loading costs (benefits, payroll taxes and paid time off) expensed through a clearing account during the test period

2002, to the actual payroll loading costs for the test period. The amounts loaded onto labor charges through the estimated payroll loading rates during the 2002 test period produced an expense level lower than the actual amount of employee benefits incurred for the test period. The impact of this true-up to actual on the Idaho gas jurisdiction decreased net operating income by $70,000.

PRO FORMA ADJUSTMENTS

Q. Please explain the significance of the 5 columns subsequent to column (o) that begin on page 6 in your Exhibit No. 15.

A. Certainly. The adjustments subsequent to column (o) are either additional normalizing adjustments or pro forma adjustments that recognize the jurisdictional impacts of material items that will impact the pro forma operating period levels for known and measurable changes. In this case, they encompass only revenue and expense items, as there were no significant natural gas 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 6.

A. Column (p), entitled **Revenue/Gas Supply Adjustment**, is a 3-fold adjustment taking into account known and measurable changes that include revenue normalization, which reprices customer usage under present 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. Revenues associated with the Schedule 191 Tariff

Rider are excluded from pro forma revenues, and the related amortization expense is eliminated as well. Mr. Hirschkorn is sponsoring this adjustment. The effect of this particular adjustment is to decrease Idaho net operating income by $112,000.

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

A. Column (q), entitled **Pro Forma Pension**, updates the 2002 pension expense to the expense accrual being recorded for 2004. Pension expense, on a system basis, was $9.4 million during the 2002 test year and has increased to $14 million for the year 2004. The issues and detail associated with the pension cost increases were outlined earlier in my Electric Section testimony. Pension costs follow labor charges, so a specific Idaho gas labor analysis was performed. To be conservative and reduce complexity, this adjustment only pro forms in the impact of increased pension costs on labor charged to operating expense accounts, not capitalized labor's impact on rate base. Pension costs that are properly charged to non-utility labor costs have also been excluded from this adjustment. The effect of this adjustment decreases Idaho net operating income by $109,000.

Column (r), **Pro Forma Insurance**, updates the 2002 insurance expense for general liability, directors and officer liability, property insurance and other policies, to the actual cost of all signed ongoing and renewed policies providing insurance for 2004. Insurance costs are mainly expensed at a system level and allocated to electric and gas, so the issues and detail associated with the insurance cost increases that were outlined earlier in my Electric Section testimony apply here as well. Insurance costs that are properly charged to non-utility operations have been excluded from this adjustment. The effect of this adjustment decreases Idaho net operating income by $131,000.

Column (s), **Pro Forma Labor-Non-Exec**, reflects known and measurable changes to test period union and non-union wages and salaries, and excludes executive salaries, which are handled separately in the next adjustment. Test period wages and salaries are restated as if the wage and salary increases for 2002, 2003 and 2004 were in place during the entire pro forma test period. The methodology behind this adjustment is similar to that used in the last Idaho general case, Case No. WWP-E-98-11, except for the separate treatment of executive salaries. The effect of this adjustment on Idaho net operating income is a decrease of $174,000.

Column (t), **Pro Forma Labor-Executive**, reflects known and measurable changes to executive compensation. During 2002 and 2003 several executives retired, a new chief financial officer was hired and responsibilities were re-assigned among the executive group. The compensation level in this adjustment is for the current executive team only. Compensation for any member of the 2002 officer team who has since left the Company has been removed from the test year by this adjustment. Compensation costs allocated to 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. The current executive group's salary allocations are set at their expected pro forma test period utility/non-utility percentage splits. The impact of this adjustment on Idaho net operating income is a decrease of $8,000.

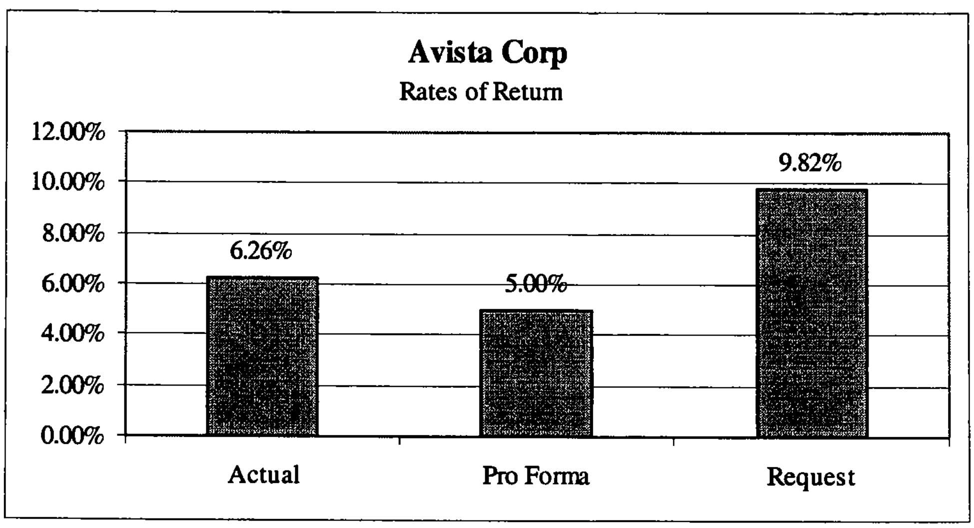
The last column on page 7, **Pro Forma Total**, reflects total 2002 pro forma results of operations and rate base consisting of 2002 actual results and the total of all standard and pro forma adjustments.

Q. Referring back to page 1, line 43, of Exhibit No. 15, what was the actual and pro forma gas rate of return realized by the Company during the test period?

A. For the State of Idaho, the actual test period rate of return was 6.26%. The test period pro forma rate of return is 5.00% under present rates. Thus, the Company does not, on a pro forma basis for the test period, realize the 9.82% rate of return requested by the Company in this case.

Q. By way of summary, could you please review the different rates of return that you have presented in your testimony?

A. Yes. Basically, there are three different ROR's discussed previously. The actual ROR earned by the Company during the test period, the Pro Forma ROR determined in my Exhibit No. 15 and the requested ROR. For convenience of comparison, please refer to the following graph:



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 9.82% rate of return on a pro forma basis?

A. The net operating income deficiency amounts to $3,039,000, as shown on line 4, page 2 of Exhibit No. 15. The resulting revenue requirement is shown on line 6 and amounts to $4,754,000, or an increase of 9.16% 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 1998 Case No. WWP-E-98-2?

A. No. For ratemaking purposes, the Company must allocate revenues, expenses and rate base between electric and gas services and between Washington, Idaho, Oregon and California jurisdictions where electric and/or gas service is provided. The current methodology was implemented at the start of 1994 and has not changed. As a result of earlier reviews, the Staff has found that the allocation system was being applied properly and produced the proper allocation of financial data. Also as part of earlier reviews, Staff has stated that the Company's rate base was properly allocated between jurisdictions.

VI. ADVANCED METER READING PROJECT ACCOUNTING PROPOSAL

Q. As previously testified by Mr. Holmes, Avista is introducing a proposal for implementation of Advanced Meter Reading ("AMR") for its Idaho customers. Does the Company have a proposal for how to account for this project?

A. Yes it does. As was noted by Mr. Holmes, the Company proposes to install AMR devices on all Idaho electric and natural gas meters over a four-year period commencing January 2005. The project will involve the installation of additional electronics for existing meters as well as other communication infrastructure, and finally computer hardware and software investment.

Due to the multi-year nature of this project, as well as the Company's desire to be able to measure and analyze both the costs and benefits of the entire project, we propose to treat AMR investment costs as a unique construction project. All capital investment would follow our standard capitalization policy and be capitalized to construction work in progress, FERC account 107, until the entire AMR project becomes operational, or used and useful. At that point, the project will be unitized into the appropriate FERC plant accounts, depreciation would begin and the investment would receive rate base treatment in regulatory filings.

Q. Why are you making this an accounting proposal in this filing?

A. There are some segments of the capital investment included in this project, specifically electronic upgrades to existing meters, and/or new meters, that an argument can be made for immediate inclusion in plant-in-service. That would mean earlier inclusion in rate base and initiation of depreciation. However, the actual AMR project would not be "completely" used and useful, at least as the whole project is defined, until some 4 years or so after the project initially begins. Keeping the capital costs bundled, as a single construction work in progress item, will facilitate easier tracking and analysis of all the aspects of the Idaho AMR program. Any slight differences in "vintaged" depreciable lives and asset balances between immediate inclusion into plant-in-service and this proposal should not be material. The Company requests approval from the Commission to account for the AMR project as described above.

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

A. Yes.