BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF SCOTT L. MORRIS
REPRESENTING AVISTA CORPORATION

Policy and Operations

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Scott L. Morris and I am employed as the Chairman of the Board, President, and Chief Executive Officer of Avista Corporation (Company or Avista), at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational background and professional experience?

A. Yes. I am a graduate of Gonzaga University with a Bachelors degree and a Masters degree in organizational leadership. I have also attended the Kidder Peabody School of Financial Management.

I joined the Company in 1981 and have served in a number of roles including customer service manager. In 1991, I was appointed general manager for Avista Utilities' Oregon and California natural gas utility business. I was appointed President and General Manager of Avista Utilities, an operating division of Avista Corporation, in August 2000. In February 2003, I was appointed Senior Vice-President of Avista Corporation, and in May 2006, I was appointed as President and Chief Operating Officer. Effective January 1, 2008, I assumed the position of Chairman of the Board, President, and Chief Executive Officer.

I am a member of the Gonzaga University board of trustees, a member of Edison Electric Institute board of directors, a member of the American Gas Association, and immediate past chair of the Washington Roundtable. On January 1, 2011, I was appointed to the Federal Reserve Bank of San Francisco, Seattle Branch board of directors, and currently serve as chair. I also serve on the board of trustees of Greater Spokane Incorporated.

During my time as general manager in Oregon, I was appointed by Governor John

Kitzhaber as a board member of the Oregon Economic and Community Development Commission. I served as a member of the board of directors and as board president of Southern Oregon Regional Economic Development Inc. I served as a director and board president of the Medford/Jackson County Chamber of Commerce. I was a board member and served as board president of the Providence Community Health Foundation. I have also served as a member of the board of directors and a board president for the Medford YMCA, as a member of the board for the Oregon Shakespeare Festival and the Rogue Valley College Regional Advisory Board.

Q. While general manager in Oregon, what were your responsibilities?

A. As general manager in Oregon, my responsibilities included accountability for all aspects of business operations for our Oregon properties.

Q. What is the scope of your testimony?

A. I will provide an overview of Avista Corporation. I will also summarize the Company's rate request in this filing, the primary factors driving the Company's need for general rate relief, and provide some background on why utility costs are continuing to increase. A large part of our need for a rate increase is driven by the costs associated with continuing to expand and replace the facilities we use every day to serve our customers. When we replace old equipment with new, it results in higher overall costs to serve customers.

My testimony will provide an overview of some of the measures we have taken to cut costs in an effort to mitigate a portion of the cost increases. I will also briefly explain the Company's customer support programs in place to assist our customers, as well as our communications initiatives to help customers better understand the changes in costs that are causing our rates to increase.

Finally, I will introduce each of the other witnesses providing testimony on the Company's behalf.

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 101. Page 1 includes a map of the Company's service territories, and page 2 includes a map of the natural gas trading hubs, interstate pipelines, and our natural gas storage facilities. This exhibit was prepared under my direction.

II. OVERVIEW OF AVISTA

Q. Please briefly describe Avista Utilities.

A. Avista Utilities provides natural gas distribution service in southwestern and northeastern Oregon. The Company, headquartered in Spokane, Washington, also provides electric and natural gas service within a 30,000 square mile area of eastern Washington and northern Idaho.[1] Of the Company's 366,305 electric and 325,919 natural gas customers (as of December 31, 2014), approximately 98,194 were Oregon customers. A map showing Avista's electric and natural gas service areas is provided in Exhibit No. 101.

As of December 31, 2014, Avista Utilities had total assets (electric and natural gas) of approximately $4.2 billion (on a system basis), with electric retail revenues of $758 million (system) and natural gas retail revenues of $314 million (system). As of December 2014, the Utility had 1,497 full-time employees.

Avista serves four counties in southwest Oregon and one county in northeast Oregon, which include Medford, Klamath Falls, Roseburg, Ashland, Grants Pass and LaGrande, as

[1] Avista also serves approximately 28 retail electric customers in western Montana.

shown on page 1 of Exhibit No. 101. The Company's Oregon service area includes approximately 82 miles of natural gas distribution mains and 2,000 miles of distribution lines. Natural gas is received at more than 20 points along interstate pipelines and distributed to our residential, commercial and industrial customers.

Avista purchases natural gas for its distribution customers in wholesale markets at multiple supply basins in the western United States and western Canada. Purchased natural gas can be transported through six connected pipelines on which Avista holds firm contractual transportation rights. These contracts provide access to both US and Canadian-sourced supply. The US-sourced gas represents approximately 20% of the contractual rights, with transportation from the Rocky Mountains. The remaining 80% comes from Alberta and British Columbia supply basins.

Avista was one of the three original developers of the natural gas storage facility at Jackson Prairie. Avista, Puget Sound Energy and Williams Northwest Pipeline each hold a one-third share of this underground gas storage facility. Development began in the 1960's and the project first went into service in 1972. A portion of this natural gas storage facility is used to serve our Oregon customers.

Q. Please describe Avista's current business focus for its utility operations.

A. Our strategy continues to focus on our energy and utility-related businesses, with our primary emphasis on the electric and natural gas utility business. There are four distinct components to our business focus for the utility, which we have referred to as the four legs of a stool, with each leg representing customers, employees, the communities we serve, and our financial investors. For the stool to be level, each of these legs must be in balance by having the proper emphasis. This means we must maintain a strong utility business by delivering efficient, reliable and high quality service at a reasonable price to our customers and the communities we serve, and provide the opportunity for sustained employment for our employees, while providing an attractive return to our investors.

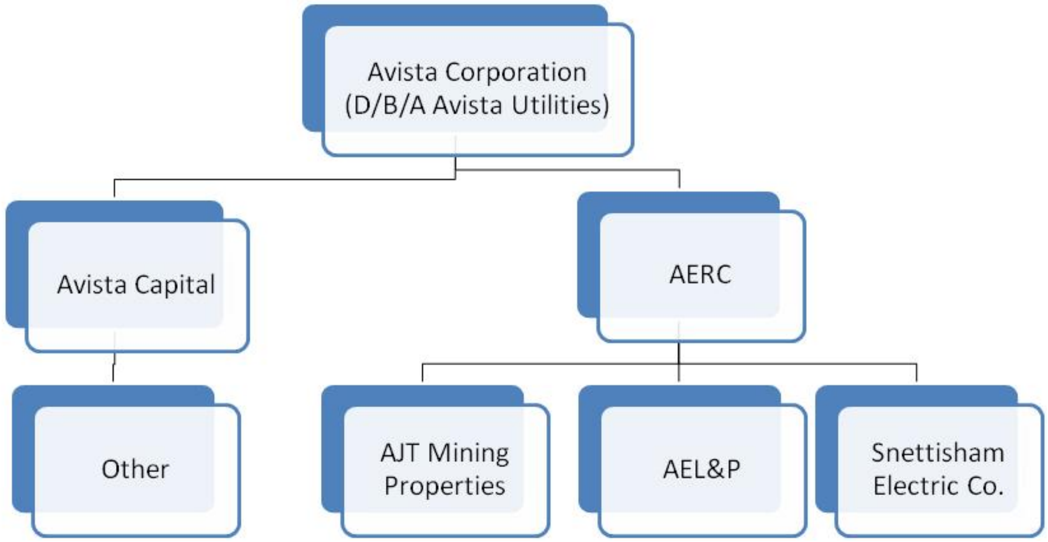
Q. Please briefly describe Avista's subsidiary businesses.

A. Mr. Thies provides an overview of our recent transactions involving the sale of our Ecova subsidiary[2], and our purchase of Alaska Energy and Resources Company (AERC), effective July 1, 2014. With the sale of Ecova, Avista Corp.'s primary subsidiary is now AERC, which includes the utility operations of Alaska Electric Light and Power (AEL&P).

The operations of AEL&P are independent of the operations of Avista Utilities. AEL&P is operated by the same employees operating the utility prior to being acquired by the Company, including the management team of AEL&P. AEL&P has 60 full-time employees. AEL&P serves approximately 15,900 retail electric customers under the authority of the Regulatory Commission of Alaska, and is the sole electric utility serving the City and Borough of Juneau, Alaska. The following is a diagram of Avista's corporate structure[3]:

[2] As a subsidiary of Avista, Ecova provided energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's service lines included expense management services for utility and telecom needs as well as strategic energy management and efficiency services that included procurement, conservation, performance reporting, financial planning, facility optimization and continuous monitoring, and energy efficiency program management for commercial enterprises and utilities.

[3] Reflects the primary subsidiaries of Avista. Other subsidiaries that have limited or no operations, or were formed for a limited purpose, are excluded.



III. AVISTA'S RATE INCREASE REQUEST

Q. Why is Avista requesting a revenue increase shortly after the conclusion of its last rate case?

A. The recent revenue increase approved effective April 16, 2015 addressed the under-recovery of utility costs the Company had experienced up to April 16, 2015, and a portion of the increased costs the Company will incur for the future rate period beginning April 16, 2015. For the calendar-year 2014, Avista's earned return on equity was approximately 7.2% on a normalized basis, which is well below the previously approved authorized return for the Company. In addition, the new revenues effective April 16, 2015 cover the cost associated with new utility plant investment only through March 31, 2015. Therefore, additional revenues from this case are necessary to cover the costs associated with significant new plant investment subsequent to March 31, 2015, as well as increased operating costs for the 2016 rate year at the conclusion of this case.

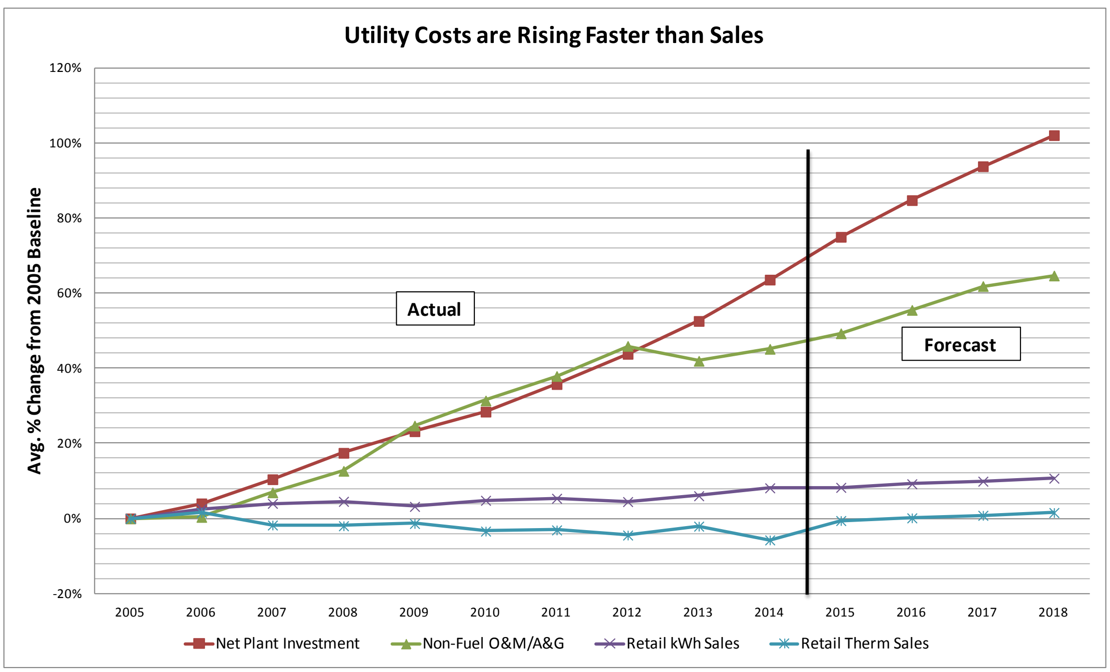
Q. What are the Company's expectations for revenue growth in future years?

A. As discussed in Dr. Forsyth's testimony, the combination of weak customer growth and flat use-per-customer would suggest relatively flat revenue growth.

Q. How does Avista's growth in net plant investment and operating expenses compare with the growth in revenue, both for the recent historical period as well as expectations for future years?

A. The graph in Illustration No. 1 below shows actual information for the period 2005 to 2014, and forecast information for 2015 to 2018 for Avista Utilities' electric and natural gas operations.

<u>Illustration No. 1:</u>



The red line on the graph shows the actual growth in net utility plant investment (electric and natural gas combined) through 2014, and the expected growth for 2015 through 2018. The purple and blue lines on the graph show the changes in retail kilowatt-hour (kWh) sales and retail therm sales, respectively, for the same time period. The graph clearly shows that net plant investment is growing at a much faster pace than sales. The green line on the graph also shows that non-fuel operations and maintenance (O&M) expenses and administrative and general (A&G) expenses are growing at a faster pace than sales. The graph in Illustration No. 1 above shows the reduction in operating expenses in 2013 (green line) related primarily to Avista's Voluntary Severance Incentive Plan (VSIP) executed in late 2012, which reduced employee complement and reduced overall operating expenses. The slope of the operating expense line for future years is also lower, which reflects additional measures taken by the Company to reduce the annual growth in expenses as discussed later in my testimony. Even with these cost-management measures, however, the growth in annual O&M is greater than the growth in sales revenue.

The graph shows this mismatch is forecast to continue to the future. Avista's Oregon operations is experiencing similar circumstances, where the costs associated with new investment and O&M are growing at a faster pace than retail sales. Therefore, it is necessary to increase retail rates in order to cover this increase in net plant investment and operating expenses, since revenue growth is not sufficient to cover it.

Q. Would you please summarize Avista Utilities' request in this filing?

A. Yes. A combination of increasing rate base and increases in general business expenses requires the Company to request an overall increase in billing rates of $8.557 million or 8.0%.[4] This request is based on a proposed rate of return of 7.72%, with a capital structure common equity component of 50%, and a 9.9% return on equity. The Company is utilizing a forecasted test year for the 2016 calendar year. The forecasted test year was selected to best

[4] The overall increase in total revenue, which includes natural gas costs and all other rate adjustments, is 8.0%. On a margin revenue basis, which excludes the cost of gas and other rate components, the overall increase is 16.1%.

reflect the conditions during the time new rates would be in effect at the conclusion of this case, as discussed further by Company witness Ms. Smith. The Company used the results of a long-run incremental cost study as a starting point in the proposed spread of the requested increase to the various customer rate schedules. Company witnesses Mr. Miller and Mr. Ehrbar testify to these rate spread issues.

Based on an average usage level of 47 therms per month, the average residential bill would increase $5.68 per month, or 8.9%, from $63.65 to $69.33.

Q. What are the primary factors causing the Company's request for a natural gas rate increase in this filing?

A. Over 65% (or approximately $5.6 million) of the Company's need for additional rate relief relates to the increase in rate base. As will be described in more detail by Company witness Ms. Schuh, these investments reflect replacement and maintenance of Avista's utility system and technology to sustain reliability, safety, and service to customers. Major projects include the continued replacement of Aldyl-A natural gas pipe, compliance with municipal requirements (i.e., street/highway relocations), and the systematic replacement of aging infrastructure, among others.

The remaining 35% (or approximately $3.0 million) of the Company's requested revenue requirement relates to an increase in operating and maintenance (O&M) and administrative and general (A&G) expenditures, and the net change in retail revenues since our last rate case filed in 2014.

Q. Is the Company proposing any changes to the cost of natural gas for its retail natural gas customers in this case?

A. No. Avista is not proposing changes in this filing related to the cost of natural gas included in current rates. Changes in natural gas costs are addressed in the annual Purchased Gas Cost Adjustment ("PGA") filing.

Q. What is the Company's current expectation related to the PGA that the Company will file in July 2015?

A. The most current estimate for the PGA that the Company will file in July, with a proposed effective date of November 1, 2015, is for an approximate 10% billing rate decrease, barring any major change in the forward wholesale price of natural gas.

IV. COST MANAGEMENT AND EFFICIENCIES

Q. What is Avista doing to manage its costs to mitigate rate increases for customers?

A. Over the last several years we have renewed our efforts to control our costs and improve efficiency. We are focused on long-term sustainable savings, while continuously improving our service to customers and managing costs into the future.

As an example, in October 2012, the Company's Board of Directors approved a Voluntary Severance Incentive Plan (VSIP) that resulted in a reduction to the total utility workforce of 55 positions effective January 1, 2013. The Company continues to operate under a hiring restriction which requires approval by myself, the President of the Utility, the CFO, and the Sr. VP for Human Resources for all replacement or new hire positions.

We also made changes to the retirement income (pension) and post-retirement medical plans offered to non-union employees, effective January 1, 2014. Changes to plans offered to the bargaining unit employees will be subject to future negotiations.

For non-union employees, with regard to retirement income, Avista no longer offers a pension plan for new hires beginning January 1, 2014. Avista will make a contribution to a 401(K) fund established for the employee, but will no longer offer a defined benefit pension plan that provides an annual annuity upon retirement.

For post-retirement medical, again for non-union employees only, beginning January 1, 2014, Avista no longer provides funding for post-retirement medical for new hires. Following retirement, new hires would be permitted to participate in Avista's retiree medical plan, but would be required to pay the full premium associated with the plan. In addition, for both existing employees and new hires, when the retiree reaches age 65, Avista will no longer provide an Avista-sponsored medical plan. At age 65, retirees may choose from a variety of plans offered by the healthcare exchange company Extend Health. For existing retirees, Avista will continue to provide a monthly contribution to the employee for healthcare, but will no longer offer a Company-sponsored healthcare plan for retirees age 65 and older. Through these changes, Avista is transitioning out of funding medical coverage for retirees.

These changes result in a reduction to Avista's future funding obligation related to pensions and post-retirement medical costs, as well as a reduction in the annual expense associated with these plans. These reductions in costs are reflected in Ms. Smith's revenue requirement calculations.

V. COMMUNICATIONS WITH CUSTOMERS

Q. How is Avista communicating with its customers to explain what is driving increased costs for the Company?

A. The Company proactively communicates with its customers in a number of ways: customer forums, one-on-one customer interactions through field personnel and account representatives, bill inserts, social media, media contacts, group presentations, and through our employees' involvement in community, business and civic organizations, to name a few. We believe our communications are helping our customers and the communities we serve to better understand the issues faced by the Company, such as increased infrastructure investment, environmental mitigation and security, all of which have led to higher costs for our customers. We are finding that once customers talk with our employees, and voice their concerns and receive answers to their questions, their satisfaction levels increase.

We are also continuing our focus on informing customers of the many programs we offer to provide assistance in managing their energy bills, and ensuring that our employees are equipped to engage in these conversations.

VI. CUSTOMER SUPPORT PROGRAMS

Q. Please explain the customer support programs that Avista provides for its customers in Oregon.

A. Avista Utilities offers a number of programs for its Oregon customers, such as the Low-Income Rate Assistance Program (LIRAP), energy efficiency programs, Project Share for emergency assistance to customers, a Customer Assistance Referral and Evaluation Service (CARES) program, level pay plans, and payment arrangements. Through these programs, the Company works to ease the burden of energy costs for customers that have the greatest need.

To assist our customers in their ability to pay, the Company focuses on actions and programs in four primary areas: 1) advocacy for, and support of, bill payment assistance programs providing direct financial assistance; 2) low income and senior outreach programs;

3) energy efficiency and energy conservation education; and 4) support of community programs that increase customers' ability to pay basic costs of living.

Q. Please describe Avista Utilities' demand-side management (DSM) or energy efficiency programs.

A. Avista Utilities' energy efficiency programs in Oregon have provided for the consistent delivery of comprehensive conservation services. Avista Utilities offers energy efficiency services to residential, commercial, and industrial customers. Programs include both audits and direct incentives for residential weatherization, high-efficiency furnace and water heaters, and commercial qualifying gas-efficiency projects.

Q. What is the Company's Low Income Rate Assistance Program or LIRAP?

A. Avista Utilities' Low-Income Rate Assistance Program (LIRAP) approved by the Commission in 2002 collects revenue under Schedule 410, "General Residential Natural Gas Service–Oregon." The current rate for LIRAP is approximately 0.4% of the current volumetric billing rate. The purpose of LIRAP is to reduce the energy cost burden among those customers least able to pay energy bills. These funds are distributed by community action agencies in a manner similar to the Federal and State-sponsored Low Income Home Energy Assistance Program (LIHEAP). Avista Utilities' LIRAP program supplements the reach of available LIHEAP funds. LIRAP provided 791 grants and distributed a total of $206,747 during the past heating season in Avista's Oregon service territory.

Q. Please describe the recent results of the Company's Project Share efforts.

A. Project Share is a community-funded program Avista sponsors to provide one-time emergency support to families in the Company's service area. Avista customers and shareholders help support the fund with voluntary contributions that are distributed through local community action agencies to customers in need. Grants are available to those in need without regard to their heating source.

Q. Does the Company offer a bill-averaging program?

A. Yes. Comfort Level Billing helps smooth out the seasonal highs and lows of customers' energy usage and provides the customer with the option to pay the same bill amount each month of the year. This allows customers to more easily budget for energy bills and it also avoids higher winter bills. This program has been well-received by participating customers.

In addition, the Company's Contact Center Representatives work with customers to set up payment arrangements to pay energy bills. In 2014, 12,198 Oregon customers were provided with over 19,080 such payment arrangements.

Q. Please summarize Avista's CARES program.

A. In Oregon, Avista is currently working with over 151 special needs customers in the CARES program. Specially-trained representatives provide referrals to area agencies and churches for customers with special needs for help with housing, utilities, medical assistance, etc.

In the last heating season (October 2013 through September 2014), 4,443 Oregon customers received $865,078 in various forms of energy assistance (Avista LIRAP, Federal LIHEAP program, Project Share, and local community funds). This program and the partnerships we have formed have been invaluable to customers who often have nowhere else to go for help.

VII. OTHER COMPANY WITNESSES

Q. Would you please provide a brief summary of the testimony of the other witnesses representing Avista in this proceeding?

A. Yes. The following additional witnesses are presenting direct testimony on behalf of Avista.

Mr. Mark Thies, Senior Vice President and Chief Financial Officer, will address the Company's capital structure, the proposed cost of embedded debt and the overall rate of return. He will explain the actions the Company has taken to acquire needed capital and improve Avista's financial condition in recent years.

Mr. Adrien M. McKenzie, as Vice President of Financial Concepts and Applications (FINCAP), Inc., has been retained to present testimony with respect to the reasonableness of the Company's proposed overall capital structure and will testify in support of the proposed 9.9% return on equity.

Ms. Jody Morehouse, Director of Gas Supply, will describe Avista's natural gas resource planning process, and provide an overview of the Company's 2014 Natural Gas Integrated Resource Plan.

Ms. Jennifer Smith, Senior Regulatory Analyst, will discuss the Company's overall revenue requirement proposal. She will also explain the 2016 test year operating results including expense and rate base adjustments made to actual operating results and rate base.

Ms. Karen Schuh, Senior Regulatory Analyst, will describe the Company's proposed regulatory treatment of capital investments in utility plant through December 31, 2015, as well as capital investments in utility plant related to new customer hookups for the 12 month period ended December 31, 2016.

Dr. Grant Forsyth, Chief Economist, describes the Company's methodology used to generate the forecasts for customers, use per customer, and total load which are used in the Company's 2016 Test Year Revenue Load Adjustment.

Mr. Joseph Miller, Senior Regulatory Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Mr. Miller discusses his study results and how each schedule's present and proposed rates compare to the indicated cost.

Mr. Patrick Ehrbar, Manager, Rates and Tariffs, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. Mr. Ehrbar also discusses the 2016 Test Year Revenue Load Adjustment and the Company's proposed Natural Gas Decoupling Mechanism.

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

A. Yes.

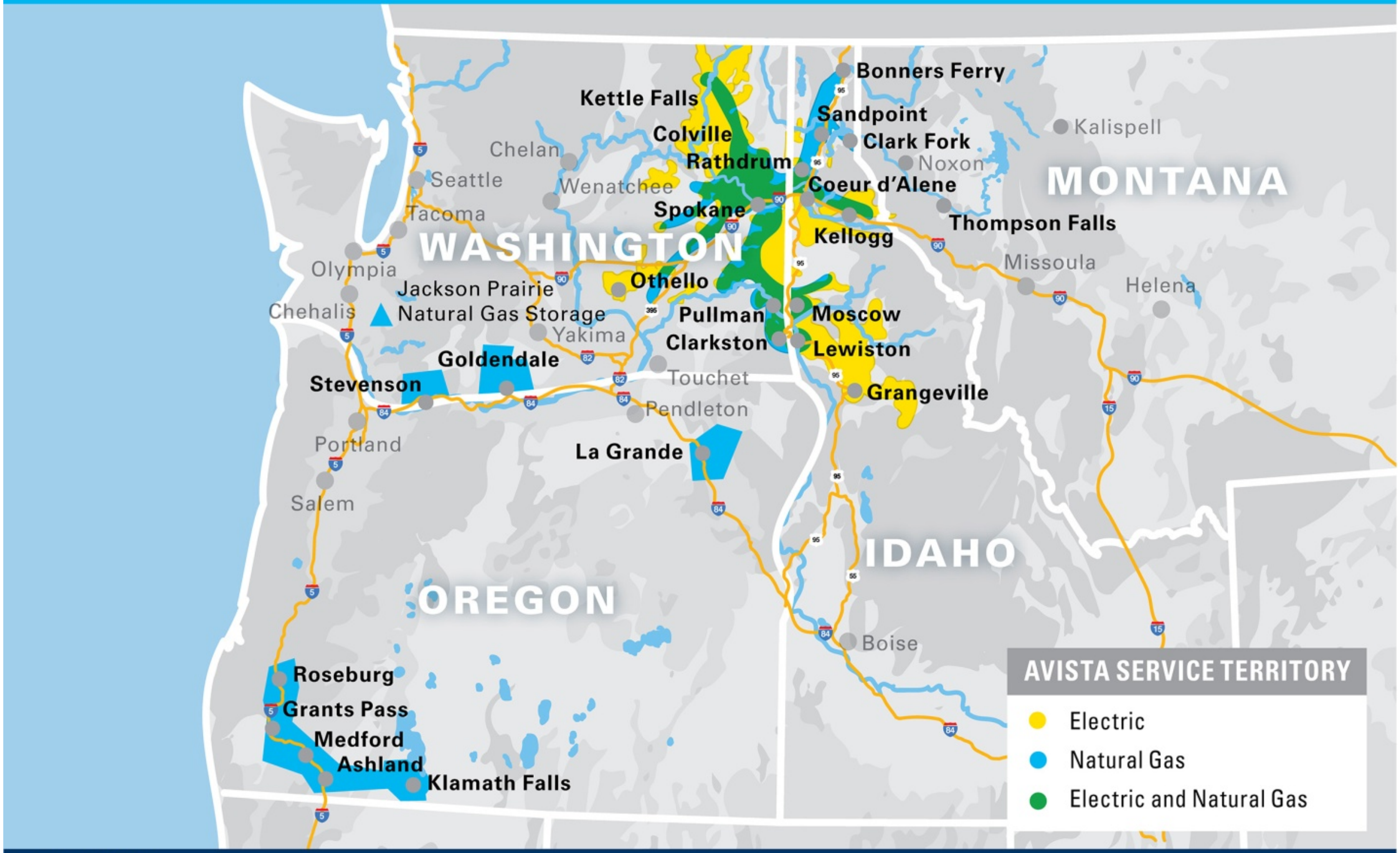
BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

SCOTT L. MORRIS
Exhibit No. 101

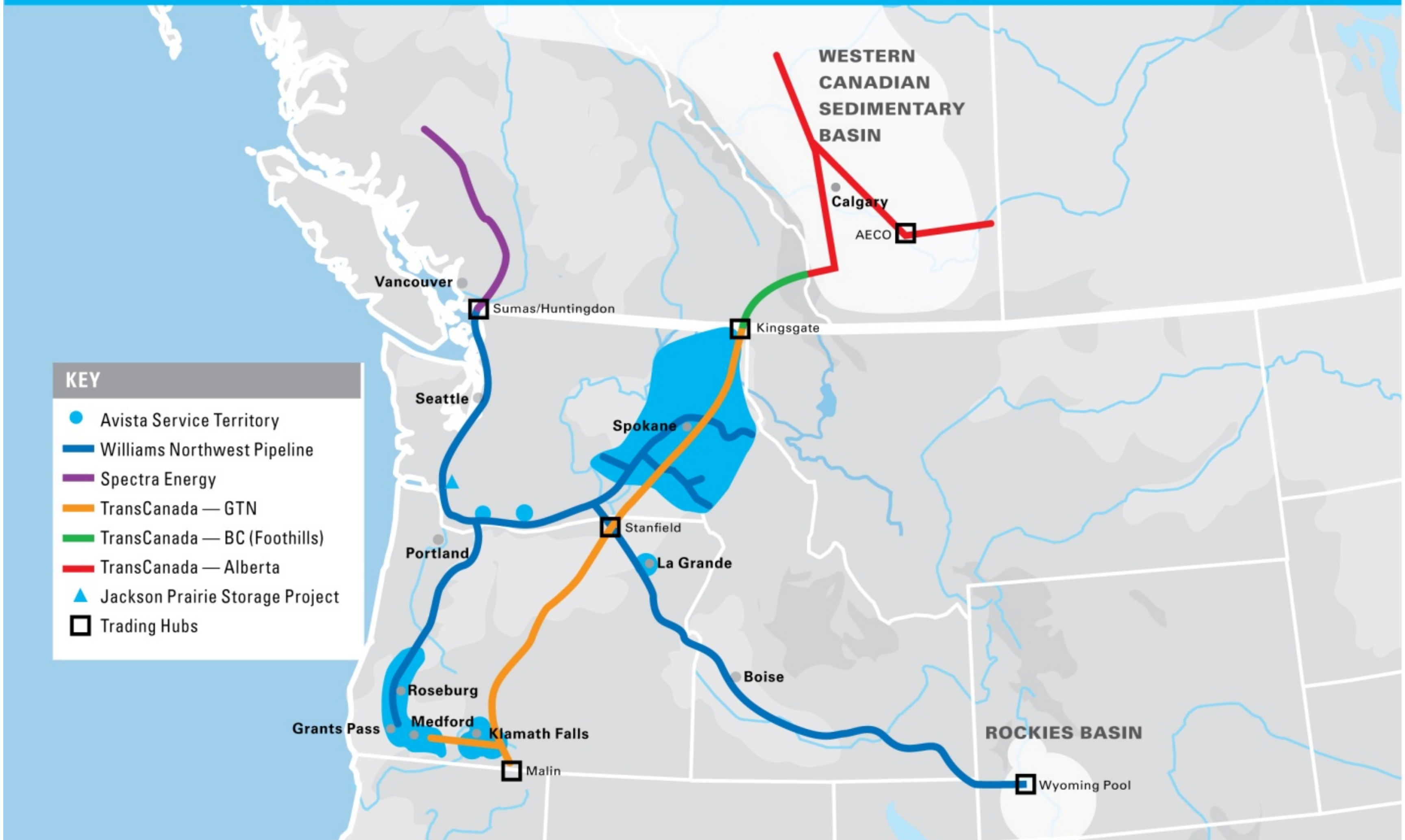
Policy and Operations

Avista Electric and Natural Gas Service Areas



as of 3/31/15

Avista Natural Gas Service Areas, Gas Fields, Trading Hubs and Major Pipelines



as of 3/31/2015

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF MARK T. THIES
REPRESENTING AVISTA CORPORATION

Financial Overview, Capital Structure and Overall Rate of Return

I. INTRODUCTION

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

A. My name is Mark T. Thies. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed by Avista Corporation as Senior Vice President, Chief Financial Officer, and Treasurer.

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

A. I received a Bachelor of Arts degree in 1986, with majors in Accounting and Business Administration from Saint Ambrose College in Davenport, Iowa, and became a Certified Public Accountant in 1987. I have extensive experience in finance, risk management, accounting and administration within the utility sector.

I joined Avista in September of 2008 as Senior Vice President and Chief Financial Officer ("CFO"). Prior to joining Avista, I was Executive Vice President and CFO for Black Hills Corporation, a diversified energy company, providing regulated electric and natural gas service to areas of South Dakota, Wyoming and Montana. I joined Black Hills Corporation in 1997 upon leaving InterCoast Energy Company in Des Moines, Iowa, where I was the manager of accounting. Previous to that I was a senior auditor for Arthur Anderson & Co. in Chicago, Illinois.

Q. What is the scope of your testimony in this proceeding?

A. I will provide a financial overview of Avista Corporation as well as explain the proposed capital structure, overall rate of return, and our credit ratings. Additionally, I will summarize our capital expenditures program. Mr. Adrien McKenzie, on behalf of Avista, will provide additional testimony related to the appropriate capital structure and return on equity for Avista, based on our specific circumstances, together with the current state of the financial markets.

In brief, I will provide information that shows:

- Avista's plans call for making significant utility capital investments in our electric and natural gas systems to preserve and enhance service reliability for our customers, including the continued replacement of aging infrastructure. Capital expenditures of $726 million are planned for 2015-2016. Capital expenditures of approximately $1.8 billion are planned for the five-year period ending December 31, 2019. Avista needs adequate cash flow from operations to fund these requirements, together with access to capital from external sources under reasonable terms, on a sustainable basis.

- We are proposing an overall rate of return of 7.72 percent, which includes a 50.0 percent common equity ratio, a 9.9 percent return on equity, and a cost of debt of 5.53 percent. We believe our proposed overall rate of return of 7.72 percent and proposed capital structure provide a reasonable balance between safety and economy.

- Avista's corporate credit rating from Standard & Poor's is currently BBB and Baa1 from Moody's Investors Service. Avista must operate at a level that will support a solid investment grade corporate credit rating in order to access capital markets at reasonable rates. A supportive regulatory environment is an important consideration by the rating agencies when reviewing Avista. Maintaining solid credit metrics and credit ratings will also help support a stock price necessary to issue equity under reasonable terms to fund capital requirements.

- Avista completed two significant business unit transactions in 2014: the sale of Ecova and the acquisition of Alaska Electric Light and Power utility operations. These transactions are supportive to our business profile and their financial impacts have positively complemented our ongoing financial structure and operations.

A table of contents for my testimony is as follows:

Description		Page
I.	Introduction	1
II.	Financial Overview	3
III.	Business Unit Transactions in 2014	4
IV.	Capital Expenditures	8
V.	Maturing Debt	12
VI.	Capital Structure	13
VII.	Proposed Rate of Return	18
VIII.	Credit ratings	24

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring Exhibit No. 201, pages 1 through 4 which were prepared under my direction. Avista's credit ratings by S&P and Moody's are summarized on page 1, and Avista's actual capital structure at December 31, 2014, and the proposed capital structure at December 31, 2016, are included on page 2, with supporting information on pages 3 and 4. Confidential Exhibit No. 202 includes our Interest Rate Risk Management Plan. Exhibit No. 203 includes the equity ratios and returns on equity approved by various state regulatory commissions from July 1, 2014 to March 31, 2015. Confidential Exhibit 204 includes the Company's planned capital expenditures and long-term debt issuances by year.

II. FINANCIAL OVERVIEW

Q. Please provide an overview of Avista's financial situation.

A. We are operating the business efficiently to keep costs as low as practicable for our customers, while at the same time ensuring that our energy service is reliable and customers are satisfied. An efficient, well-run business is not only important to our customers but also important to investors. Our capital financing plan and our execution of that plan provide a prudent capital structure and liquidity necessary for utility operations. We initiate regulatory processes to recover our costs in a timely manner with the goal of achieving earned returns close to those allowed by regulators in each of the states we serve. These elements – cost management, capital and revenues that support operations – are key determinants to the rating agencies when they are reviewing our overall credit ratings.

Q. What are steps the Company is taking to maintain and improve its financial health?

A. We are working to assure there are adequate funds for operations, capital expenditures and debt maturities. We obtain a portion of these funds through the issuance of long-term debt, which is supported by our interest rate risk mitigation plan, and we maintain a proper balance of debt and common equity through regular securities issuances and other transactions. We create financial plans and forecasts to model our income, expenses and investments, providing a basis for prudent financial planning. We seek timely recovery of our costs through general rate cases and other ratemaking mechanisms.

The Company currently has a sound financial profile and it is very important for Avista to maintain and enhance its financial position in order to access debt and equity financing as Avista funds significant future capital investments and refinances maturing debt.

III. BUSINESS TRANSACTIONS IN 2014

Q. The Company completed two significant business unit transactions in 2014. Please give an overview of these transactions.

A. On June 30, 2014, the Company completed the sale of its former Ecova business unit to Cofely USA Inc, an indirect subsidiary of GDF SUEZ, a French multinational utility company. On July 1, 2014, the Company acquired Alaska Energy and Resources Company (AERC) by issuing Avista common stock to the holders of AERC common stock in exchange for their shares. AERC's primary subsidiary is Alaska Electric Light and Power Company (AEL&P), which provides electric service to the City and

Borough of Juneau, Alaska. These business unit transactions also led the Company to implement a common stock share repurchase program.

Q. How did the Ecova sale transaction affect Avista's capital structure?

A. Avista received cash for the sale of Ecova. The price for the Ecova sale was $335 million, which was reduced for payment of debt and other customary closing adjustments. After repayment of debt and payments to Ecova option holders and non-controlling interests, and deductions for transaction expenses and a portion of proceeds held in escrow, the net cash to Avista at closing was $205.4 million. Avista's gain on the transaction resulted in income tax obligations of approximately $85.8 million. Avista expects to receive approximately $13.6 million from the escrow later in 2015, resulting in total net cash proceeds to Avista of $133.2 million. Certain post-closing adjustments may affect the final net proceeds and an indemnity escrow will be held until 15 months after the transaction closed.

The cash proceeds received on June 30, 2014, were initially used to reduce Avista's outstanding borrowings on the short-term bank credit facility, which reduced the outstanding balance from $151.5 million to zero, and a portion of the cash was placed in temporary investments.

Q. How did the AERC acquisition transaction, which closed on July 1, 2014, affect Avista's capital structure?

A. We initially funded this acquisition with the issuance of Avista common stock in exchange for the outstanding shares of AERC common stock. The purchase price for AERC at closing was $170 million, plus acquired cash of $19.7 million less the assumption of $38.8 million of outstanding debt and other closing adjustments per the merger agreement. The Avista common stock issued in exchange for AERC common stock was valued under the merger agreement at $32.46 per share, resulting in issuance of 4.5 million new shares of Avista common stock. The value of these shares based on the day of issue at a market price of $33.35 per share was $150.1 million. The transaction also required a cash payment of $4.7 million.

Following the closing of the transaction, debt was issued by AEL&P and by AERC to rebalance the capital structures of AEL&P and AERC. AEL&P issued $75 million of first mortgage bonds, backed by the assets of AEL&P, and paid off all of its outstanding debt (excluding debt related to a purchased power contract)[1]. AEL&P paid a $50 million dividend (via its parent, AERC) to Avista. AERC entered into a $15 million five-year term loan and paid a $15 million dividend to Avista. These funds from AERC and AEL&P were transferred to Avista, providing $65 million for utility capital investment and utility operating costs at Avista, and reduced Avista's external financing that would have otherwise occurred without these transactions. At December 31, 2014 AERC's capital structure was 49.7% equity and 50.3% debt.

AERC became a wholly-owned corporation of Avista. AEL&P, a vertically integrated electric utility providing electric service to the City and Borough of Juneau, continues to be a wholly-owned corporation of AERC. AERC and AEL&P are separate legal entities and their debt is backed by the assets and equity of AERC and AEL&P, and holders of their debt have no recourse against Avista. Avista does not provide collateral or guarantees related to AERC or AEL&P debt. The debt and equity of AERC are excluded from the capital structure proposed in Avista's Oregon rate filings.

[1]AERC's debt and debt percentages referred to in this testimony exclude the debt obligation related to a power purchase agreement (PPA) contract held by AEL&P related to the Snettisham hydro electric generation facility.

Q. How did Avista's share repurchase program affect the Company's capital structure?

A. As I described earlier, we received cash proceeds from the sale of Ecova and we issued common stock to acquire AERC. The cash sale of Ecova and acquisition of AERC through the issuance of equity were completed, almost simultaneously, midway through 2014. We also completed new debt transactions to recapitalize AERC and AEL&P during the second half of 2014. These transactions provided a significant amount of cash to Avista, added significant equity to Avista's capital structure, and decreased debt.

The Company entered into a common stock repurchase program in 2014 to acquire shares of Avista common stock with cash. The share repurchase program was designed to reduce equity and move our overall capital structure closer to our target, which includes an equity ratio for our Oregon operations of approximately 50% equity.

We implemented a share repurchase program in June of 2014, prior to closing on the Ecova sale and contingent on the Ecova sale being completed as planned. The program allowed open market purchases of Avista common shares to start on July 7, 2014, with repurchase transactions carried out by an agent independent of Avista. The program authorized up to four million shares to be repurchased by December 31, 2014, subject to various parameters that were set in June 2014. Daily purchase volumes and prices were dependent on the market for Avista shares. The Company retained the right to terminate the program at any time and could not guaranty that the authorized number of shares would be repurchased. When the program expired December 31, 2014, the repurchases totaled 2,529,615 shares at a total cost of $79.9 million for an average cost of $31.57 per share. On

December 31, 2014, Avista's common equity percentage for the Oregon jurisdiction was 50.4%.

We implemented a second share repurchase program in December 2014, based on an expectation that the 2014 program would not reach the four million share maximum before it expired on December 31, 2014. The second program authorized up to 800,000 shares to be purchased during the first quarter of 2015, subject to certain daily volume and price parameters. When the program expired March 31, 2015, the repurchases totaled 89,400 shares at a total cost of $2.7 million for an average cost of $32.66 per share.

IV. CAPITAL EXPENDITURES

Q. What is the Company's recent history related to capital investments?

A. We are making significant capital investments in electric generation, transmission and distribution facilities, our natural gas distribution system, and new technology to better serve the needs of our customers. These investments target, among other things, the preservation and enhancement of safety, service reliability and the replacement of aging infrastructure. For the period 2011 through 2014, our capital expenditures totaled $1.15 billion. While there are variations among the functional areas targeted for investment each year, the predominant areas have included electric generation, transmission and distribution facilities, natural gas distribution plant, new customer hookups, environmental and regulatory requirements, information technology and other supporting functions, such as fleet services and facilities.

Q. In general, has the overall level of capital investment during these years (2011-2014) matched the annual capital requests submitted by the Company's various departments?

A. No. As Ms. Schuh explains in her testimony, Avista has a Capital Planning Group that meets regularly to review and prioritize proposed utility capital investment projects. Avista has typically chosen not to fund all of the capital investment projects proposed by the various departments, driven primarily by the Company's desire to mitigate the retail rate impacts to customers. Decisions to delay funding certain projects are made only in cases where the Company believes the amount of risk associated with the delay is reasonable and prudent.

Q. What does Avista consider in setting the overall level of capital investment each year?

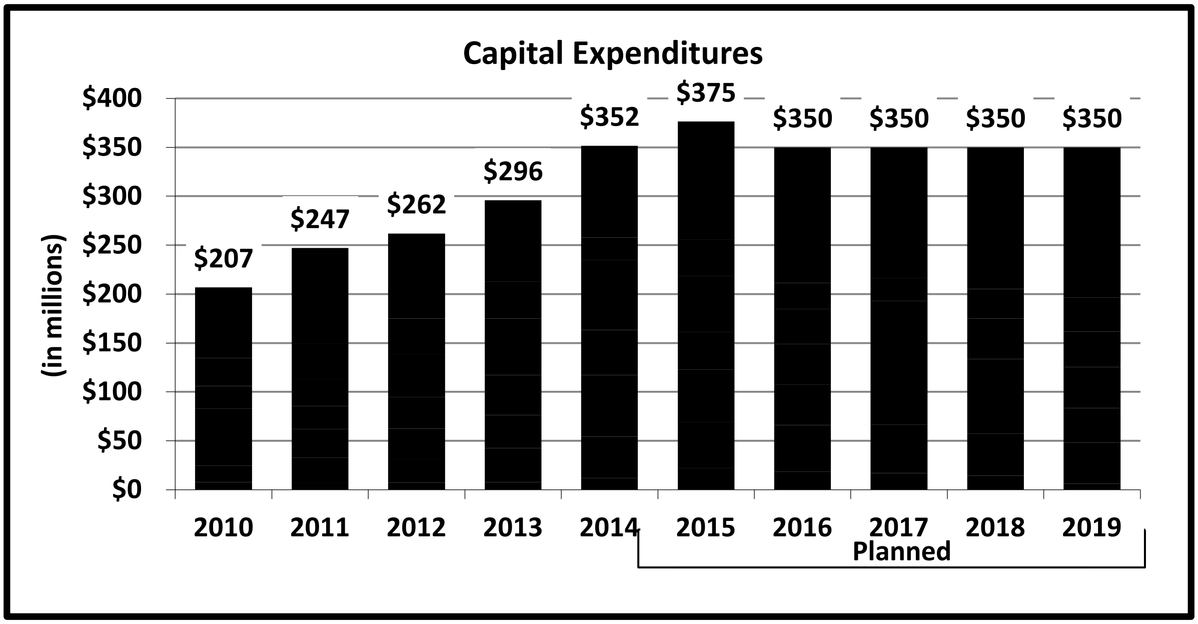
A. A range of factors influences the level of capital investment made each year, including: 1) the level of investment needed to meet safety, service and reliability objectives and to further optimize our facilities; 2) the degree of overall rate pressure faced by our customers; 3) the variability of investments required for major projects; 4) unanticipated capital requirements, such as an unplanned outage on a large generating unit; 5) the cost of debt; and 6) the opportunity to issue equity on reasonable terms.

Q. What are Avista's planned capital expenditure levels for the next five years?

A. We expect to continue investing at a similar level as 2014 for the next five years, with a slightly higher amount in 2015 to complete certain larger projects. The chart in

Illustration No. 1 below summarizes the capital expenditure levels for recent years, as well as planned expenditures through 2019.

<u>Illustration No. 1:</u>



After the Company's expected $375 million capital investments in 2015, the capital expenditure level is expected to be $350 million annually from 2016 through 2019.

Q. Why did the Company increase the level of its capital expenditures in recent years?

A. Three primary drivers have affected Avista's level of capital investment: 1) the business need to fund a greater portion of the departmental requests for new capital investments that in the past have not been funded; 2) the need to capture investment opportunities and benefits identified by our asset management capabilities, and 3) a continued focus on controlling the increase in operation and maintenance (O&M) spending through prudent capital investment.

Q. Please provide some examples that illustrate the key drivers.

A. Our aging and changing infrastructure provides several challenges we need to manage to keep costs under control into the future. Asset management programs and projects include wood pole management, Aldyl-A pipe replacement, transmission line rebuilds, and substation equipment replacements and rebuilds. These asset management capital investments are replacing old and failing assets using a planned and systematic approach to reduce outages, control costs to benefit customers over the life of these assets, and reduce risks associated with failed equipment.

Q. Are there other reasons Avista believes this increased level of capital spending is appropriate?

A. Yes. Interest rates remain near all-time lows, so funding these capital projects now will result in a lower long-term cost to customers, rather than waiting until interest rates and inflation rise. In addition, Avista currently does not have a need for new capacity and energy resources or new renewable resources, which would otherwise put upward pressure on retail rates. Furthermore, electric and natural gas commodity costs continue to be relatively stable as compared to past years, and are expected to remain relatively stable for the near future.

Funding the additional needed capital investment projects now will result in lower overall bill impacts to customers rather than waiting until a time when retail rates are being driven higher by increasing commodity costs, construction of new capacity and energy resources, and/or higher inflation and interest rates.

V. MATURING DEBT

Q. How is Avista affected by maturing debt obligations in the next five years?

A. In the next five years the Company is obligated to repay maturing long-term debt totaling $452.5 million. The table in Illustration No. 2 below shows the Company's maturing long-term debt from 2015 through 2019. Within this five-year period, a large concentration – $272.5 million – matures within the second quarter of 2018.

Illustration No. 2:

Avista Corp.
Long-Term Debt Maturities, 2015 to 2019

Maturity Year	Principal Amount	Coupon Rate	Date Issued	Maturity Date
2015	$ 0	-	-	-
2016	$ 90,000,000	0.840%	8-14-2013	8-14-2016
2017	$ 0	-	-	-
2018	$ 7,000,000	7.390%	5-11-1993	5-11-2018
	$ 250,000,000	5.950%	4-3-2008	6-1-2018
	$ 15,500,000	7.450%	6-9-1993	6-11-2018
2019	$ 90,000,000	5.450%	11-18-2004	12-1-2019
Total	**$ 452,500,000**			

These debt obligations originated as early as 1993 and their original terms were three, ten, fifteen and twenty-five years. These maturing obligations represent nearly a third (32.5%) of the Company's long-term debt outstanding at the end of 2014, which is a significant portion of our capital structure. The Company typically replaces maturing long-term debt with new issuances of debt. It will be necessary for Avista to be in a favorable financial position to complete the expected debt refunding, under reasonable terms, while also obtaining debt and equity to fund capital expenditures each year.

Q. What are the Company's expected long-term debt issuances through 2019?

A. To provide adequate funding for the significant capital expenditures noted in Section IV above and to repay maturing long-term debt, we are forecasting the issuance of long-term debt in each year through 2019. We plan to issue $100 million in 2015. Issuances planned for 2016 through 2019 are provided in confidential Exhibit No. 204C.

Q. Are there other debt obligations that the Company must consider?

A. Yes. In addition to long-term debt, the Company's $400 million revolving credit facility expires in April 2019. The Company relies on this credit facility to provide, among other things, funding to cover month-to-month variations in cash flows, interim funding for capital expenditures, and credit support in the form of cash and letters of credit that are required for energy resources commitments and other contractual obligations. Our credit facility was amended in April 2014, which stretched the expiration date to April 2019, five years past the amendment date, and reduced interest rates and fees. We expect to initiate the renewal or replacement of the credit facility before the existing arrangement expires. Any outstanding balances borrowed under the revolving credit facility become due and payable when the facility expires. Again, a strong financial position will be necessary to gain access to a new or renewed revolving credit facility, under reasonable terms, prior to expiration of the existing facility.

VI. CAPITAL STRUCTURE

Q. What are the capital structure and rate of return the Company requests in this proceeding?

A. Our requested capital structure is 50.0 percent debt and 50.0 percent equity with a requested overall rate of return in this proceeding of 7.72 percent, as shown in Illustration No. 3 below. The requested capital structure is based on our forecasted capital structure at December 31, 2016.

Illustration No. 3:

AVISTA CORPORATION Proposed Cost of Capital			
	Proposed Structure	Cost	Component Cost
Total Debt	50.0%	5.53%	2.77%
Common Equity	50.0%	9.90%	4.95%
Total	100.0%		**7.72%**

Q. Is the capital structure reflected in Illustration No. 3 above calculated in a manner similar to the capital structure calculated in Avista's recent rate proceedings?

A. Yes, with certain updates. This methodology considers debt and equity outstanding for our Avista Utilities' regulated business, including the impact of costs related to the issuance of that debt and equity.

In recent rate proceedings our capital structure calculation considered the impact of our former subsidiary, Ecova. The Ecova impact is completely removed since Ecova was sold in mid-2014.

The capital related to AERC and its subsidiary, AEL&P, does not impact the capital structure calculation for the Avista Utilities' rate proceeding. Debt and equity for AERC, which was acquired in mid-2014, are excluded from this calculation for Avista Utilities.

Q. How does the Company determine the amount of long-term debt and common equity to be included in its capital structure?

A. As a regulated utility, Avista has a continuing obligation to provide safe and reliable service to customers while balancing safety and economy, in both the short term and long term. Through our planning process, we determine the amount of new financing needed to support our capital expenditure programs while maintaining an optimal capital structure that balances and supports our current credit ratings and provides flexibility for anticipated future capital requirements.

Q. Why is the Company proposing a 50.0 percent equity ratio?

A. On December 31, 2014, Avista's common equity percentage for the Oregon jurisdiction was 50.4%. The Company continues to evaluate the extent and timing of equity issuances for 2015, taking into account our capital expenditures and other financial requirements.

Maintaining a 50.0 percent common equity ratio has several benefits for customers. We are dependent on raising funds in capital markets throughout all business cycles. These cycles include times of contraction and expansion. A solid financial profile will assist us in accessing debt capital markets on reasonable terms in both favorable financial markets and when there are disruptions in the financial markets.

Additionally, a 50.0 percent common equity ratio solidifies our current credit ratings and supports our long-term goal of moving our corporate credit rating from BBB to BBB+.

A rating of BBB+ would be consistent with the natural gas and electric industry average, which I will further explain later in my testimony. We rely on credit ratings in order to access capital markets on reasonable terms. Moving further away from non-investment grade (BB+) provides more stability for the Company, which is also beneficial for customers. We believe our requested 50.0 percent equity ratio appropriately balances safety and economy for customers.

Q. In attracting capital under reasonable terms, is it necessary to attract capital from both debt and equity investors?

A. Yes, it is absolutely essential. As a publicly traded company we have two primary sources of external capital: debt and equity investors. As of December 31, 2014, we had approximately $2.8 billion of long-term debt and equity. Approximately half of our capital structure is funded by debt holders, and the other half is funded by equity investors and retained earnings. Rating agencies and potential debt investors place significant emphasis on maintaining credit metrics and credit ratings that support access to debt capital markets under reasonable terms. Leverage – or the extent that a company uses debt in lieu of equity in its capital structure – is a key credit metric and, therefore, access to equity capital markets is critically important to long-term debt investors. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors.

The level of common equity in our capital structure can have a direct impact on investors' decisions. A balanced capital structure allows us access to both debt and equity markets under reasonable terms, on a sustainable basis. Being able to choose specific financing methods at any given time also allows the Company to take advantage of better choices that may prevail as the relative advantages of debt or equity markets can ebb and flow at different times.

Q. Are the debt and equity markets competitive markets?

A. Yes. Our ability to attract new capital, especially equity capital, under reasonable terms is dependent on our ability to offer a risk/reward opportunity that is equal to or better than the equity investors' other alternatives. We are competing not only with other utilities, but also with businesses in other sectors of the economy. Demand for our stock supports our stock price, which provides us the opportunity to issue additional shares under reasonable terms to fund capital investment requirements.

Q. What is Avista doing to attract equity investment?

A. We are requesting a capital structure that provides us the opportunity to have financial metrics that offer a risk/reward proposition that is competitive and/or attractive for equity holders.

We have steadily increased our dividend for common shareholders over the past several years, to work toward a dividend payout ratio that is comparable to other utilities in the industry. This is an essential element in providing a competitive risk/reward opportunity for equity investors.

Tracking mechanisms, such as the Purchased Gas Adjustment approved by the regulatory commissions, and the proposed decoupling mechanism, help balance the risk of owning and operating the business in a manner that places us in a position to offer a risk/reward opportunity that is competitive with not only other utilities, but with businesses in other sectors of the economy.

VII. PROPOSED RATE OF RETURN

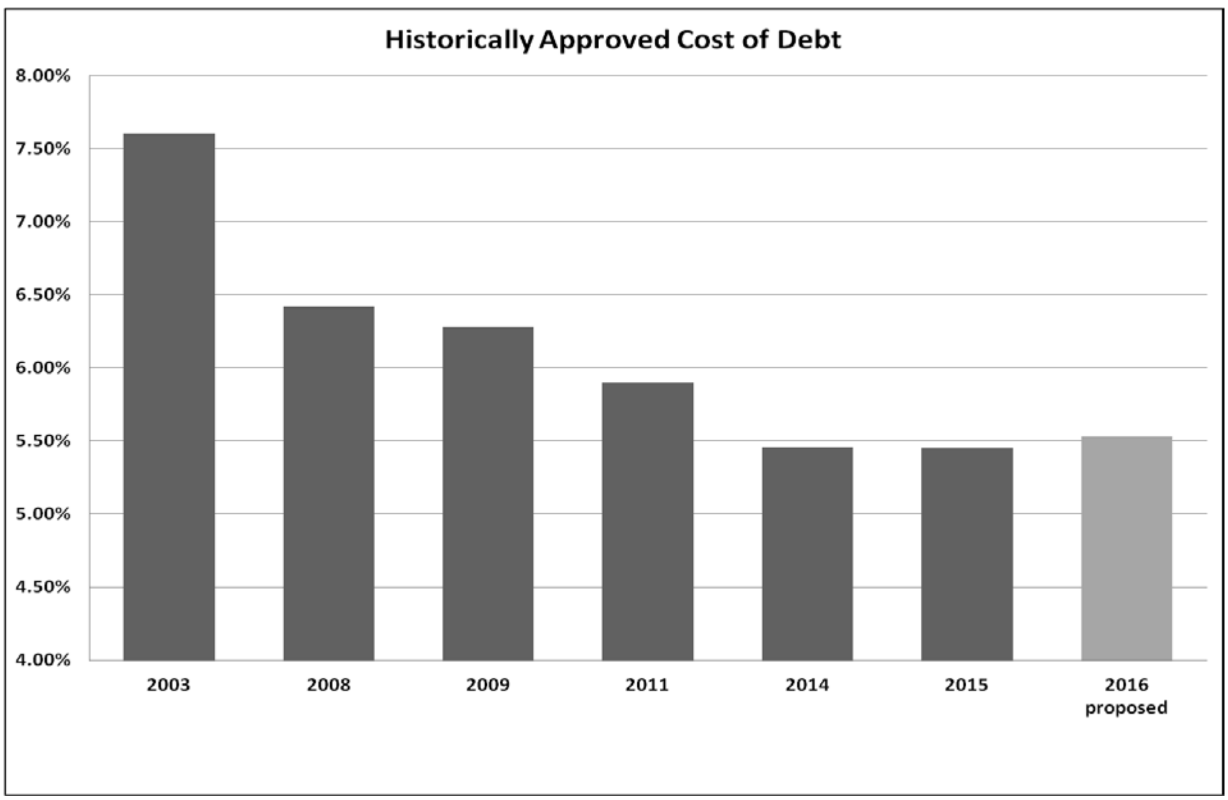
Q. Has Avista prepared an exhibit that includes the components of Avista's requested rate of return of 7.72 percent?

A. Yes. Page 2 of Exhibit No. 201 shows the components of Avista's requested rate of return of 7.72 percent.

Q. What is the Company's overall cost of debt, and how does it compare to its historically-approved cost?

A. Our requested overall cost of debt is 5.53 percent.[2] The cost of debt has trended downward for Avista from 2003 to 2015, as shown in Illustration No. 4 below.

Illustration No. 4:



[2] 5.53% is the forecasted cost of debt at December 31, 2016. The forecasted cost of debt at December 31, 2015 is 5.34%

Q. Please explain why Avista's cost of long-term debt has continued to decrease.

A. There has been a general decline in interest rates for several years while Avista has issued new debt, causing the Company's overall cost of debt to decrease. We have been prudently managing our interest rate risk in anticipation of these periodic debt issuances, which has involved fixed rate long-term debt with varying maturities, and executing forward starting interest rate swaps to mitigate interest rate risk on a portion of the future maturing debt and our overall forecasted debt issuances.

From 2011 through 2014 we issued $315 million in long-term debt. The weighted average rate of these issuances is 3.30 percent. These issuances have varying maturities ranging from 3 years to 35 years, and a weighted average maturity of 23.6 years.

Our most recent issuance (in 2014) was $60 million of first mortgage bonds with a thirty-year maturity at a rate of 4.11 percent. This new debt, which matures in 2044, is the lowest priced debt with a term beyond twenty years that the Company has issued since the 1950s. The effective cost of this debt is even lower at 3.65%, which includes the cost of issuance and the impact of interest rate hedges. The $5.4 million positive value of the interest rate hedges (hedges were settled when the coupon rate was set) improved the effective yield on this debt by 0.52%. I will discuss the interest rate hedging program later in my testimony.

The prior year (in 2013) we issued $90 million of three-year debt (maturing in 2016) at a very favorable rate of 0.84%. The effective cost of this debt is a negative 0.04%, which includes the cost of issuance and the impact of interest rate hedges. We received $2.9

million for settled interest rate hedges, which improved the effective yield on this debt by 1.07%.

We have continued to issue debt with varying maturities to balance the cost of debt and the weighted average maturity. This practice has provided us with the ability to take advantage of historically low rates on both the short end and long end of the yield curve.

The Company's credit ratings have supported reasonable demand for Avista debt by potential investors. We have further enhanced credit quality and reduced interest cost by issuing debt that is secured by first mortgage bonds.

We plan to continue issuing long-term debt with various maturities for the foreseeable future in order to fund our capital expenditure program and long-term debt maturities.

Q. What is the Company doing to mitigate interest rate risk related to future long-term debt issuances?

A. Our future borrowing requirements are primarily driven by our significant capital expenditure program and maturing debt, which creates exposure to interest rate risk. As mentioned earlier, we have $1.8 billion in forecasted capital expenditures over the next five years. Additionally, we have $452.5 million of debt maturing during the same period. We are forecasting the issuance of approximately $900 million in long-term debt from 2015 through 2019 to fund these capital expenditures and maturing debt while maintaining an appropriate capital structure.

We usually rely on short-term debt as interim financing for capital expenditures, with issuances of long-term debt in larger transactions approximately once a year. As a result, we access long-term debt capital markets on limited occasions, so our exposure to prevailing long-term interest rates can occur all at once rather than across market cycles. To mitigate interest rate risks, we hedge the rates for a portion of forecasted debt issuances over several years leading up to the date we anticipate each issuance.

We also manage interest rate risk exposure by limiting the extent of outstanding debt that is subject to variable interest rates rather than fixed rates. In addition, we issue fixed rate long-term debt with varying maturities to manage the amount of debt that is required to be refinanced in any period (looking ahead to its future maturity), and to obtain rates across a broader spectrum of prevailing terms which tend to be priced at different interest rates.

Q. Does the Company have guidelines regarding its interest rate risk management?

A. Yes. The Company's Interest Rate Risk Management Plan, attached as Confidential Exhibit No. 202, is designed to provide a certain level of stability to future cash flows and the associated retail rates related to future interest rate variability. The plan provides guidelines for hedging a portion of interest rate risk with financial derivative instruments. We settle these hedge transactions for cash simultaneously when a related new fixed-rate debt issuance is priced in the market. The settlement proceeds (which may be positive or negative) are amortized over the life of the new debt issuance.

The interest rate risk management plan provides that hedge transactions are executed solely to reduce interest rate uncertainty on future debt that is included in the Company's five-year forecast. The hedge transactions do not involve speculation about the movement of future interest rates.

Q. The Company is requesting a 9.9 percent return on equity. Please explain why the Company believes this is reasonable?

A. We agree with the analyses presented by Company witness Mr. McKenzie which demonstrate that the proposed 9.9 percent ROE, together with the proposed equity layer of 50 percent, would properly balance safety and economy for customers, provide Avista with an opportunity to earn a fair and reasonable return, and provide access to capital markets under reasonable terms on a sustainable basis. The proposed weighted cost of equity is 4.95% (9.9% times 50%).

Q. How does Avista's requested 4.95 percent weighted cost of equity compare with the weighted cost of equity recently approved for electric and natural gas utilities in other jurisdictions?

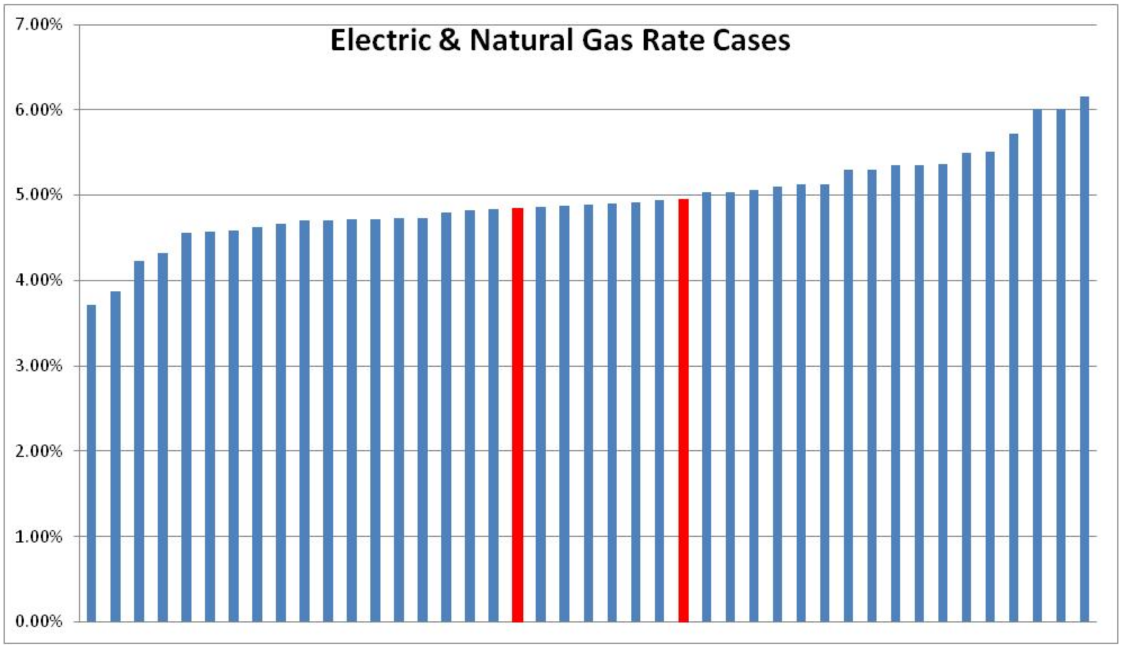
A. The bar charts in Illustration Nos. 5 and No. 6 below show the weighted cost of equity approved by state regulators for investor-owned utilities across the country for the period from July 1, 2014 through March 31, 2015. Illustration No. 5 includes electric and natural gas utilities, whereas Illustration No. 6 includes natural gas utilities only. These data in the bar chart represent all of the commission decisions that specify an ROE and equity ratio for utilities in the most recent nine-month period.

Avista's proposed weighted cost of equity of 4.95 percent, which is also shown in the charts, is in the middle of the range of these weighted cost of equity numbers. Avista's current authorized weighted cost of equity of 4.85 percent is also shown on the charts, which is based on a 51 percent equity ratio and a 9.5 percent ROE. Additional details related to these charts, including the names of the utilities, are provided in Exhibit No. 203.

Because Avista competes with other utilities for equity investor dollars, it is important for Avista to be able to provide an earnings opportunity that is competitive with other utilities.

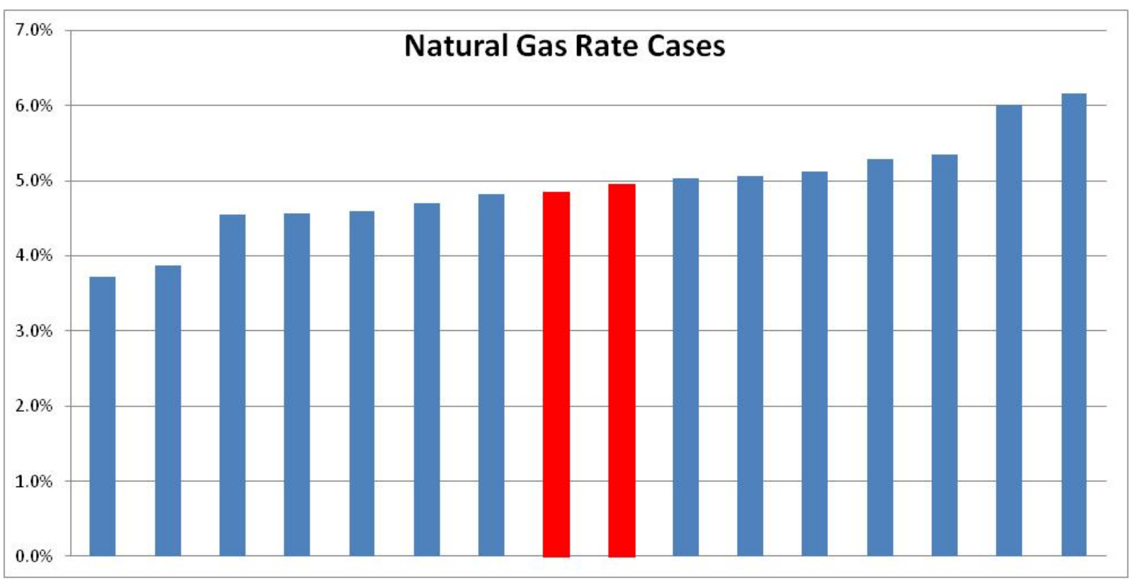
<u>Illustration No. 5[3]:</u>

Weighted Cost of Equity: Electric and Natural Gas Rate Cases



<u>Illustration No. 6[4]:</u>

Weighted Cost of Equity: Natural Gas Rate Cases



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3 *Source: SNL Financial. Rate Cases finalized July 1, 2014 through March 31, 2015.
Items added (red bars): 1) Avista's April 2015 approved return from the Oregon Commission and 2) Avista's proposed return in the current filing.

4 *Source: SNL Financial. Natural Gas Rate Cases finalized July 1, 2014 through March 31, 2015.
Items added (red bars): 1) Avista's April 2015 approved return from the Oregon Commission and 2) Avista's proposed return in the current filing.

VIII. CREDIT RATINGS

Q. How important are credit ratings for Avista?

A. Utilities require ready access to capital markets in all types of economic environments. The capital intensive nature of our business with energy supply and delivery dependent on costly long-term capital projects to fulfill our obligation to serve customers necessitates the ability obtain funding from the financial markets under reasonable terms at regular intervals. In order to have this ability, investors need to understand the risks related to any of their investments. Financial commitments by our investors generally stretch for many years – even decades – and the potential for volatility in costs (arising from energy commodities, natural disasters and other causes) is a key concern to them. To help investors assess the creditworthiness of a company, nationally recognized statistical rating organizations (rating agencies) developed their own standardized ratings scale, otherwise known as credit ratings. These credit ratings indicate the creditworthiness of a company and assist investors in determining if they want to invest in a company and its comparative level of risk compared to other investment choices.

Q. Please summarize the credit ratings for Avista.

A. Avista's credit ratings, assigned by Standard & Poor's (S&P) and Moody's Investors Service are as follows:

	S&P	Moody's
Senior Secured Debt	A-	A2
Senior Unsecured Debt	BBB	Baa1
Outlook	Stable	Stable

Additional information on our credit ratings has been provided on page 1 of Exhibit No. 201.

Q. Please explain the implications of the credit ratings in terms of the Company's ability to access capital markets.

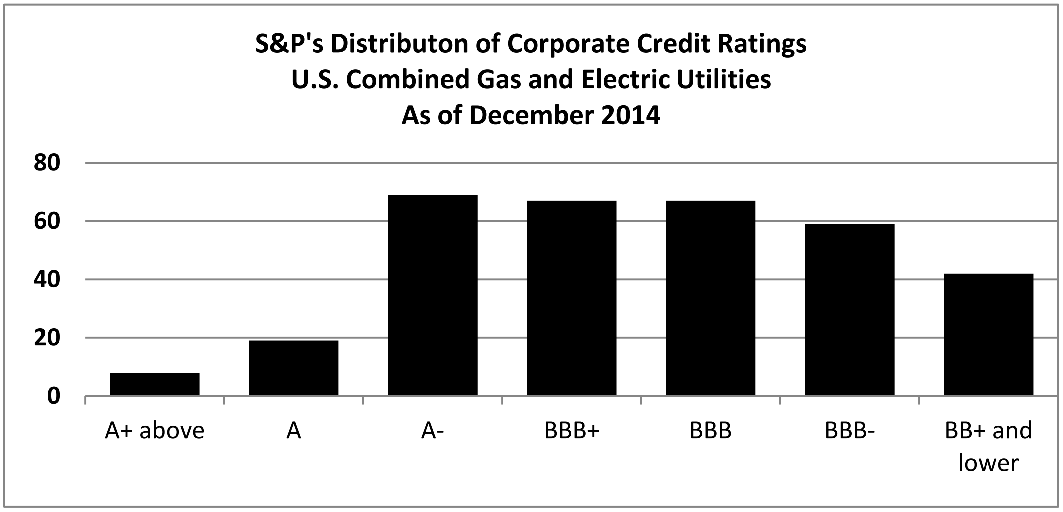
A. Credit ratings impact investor demand and expected returns. More specifically, when we issue debt the credit rating can affect the determination of the interest rate at which the debt will be issued. Credit ratings can also affect the type of investor who will be interested in purchasing the debt. For each type of investment a potential investor could make, the investor looks at the quality of that investment in terms of the risk they are taking and the priority they would have for payment of principal and interest in the event that the organization experiences severe financial stress. Investment risks include, but are not limited to, liquidity risk, market risk, operational risk, and credit risk. These risks are considered by S&P, Moody's and investors in assessing our creditworthiness.

In challenging credit markets, where investors are less likely to buy corporate bonds (as opposed to U.S. Government bonds), a higher credit rating will attract more investors, and a weaker credit rating could reduce or eliminate the number of potential investors. Thus, weaker credit ratings may result in a company having more difficulty accessing capital markets and/or incur significantly higher costs when accessing capital.

Q. What credit rating does Avista Corporation believe is appropriate?

A. Avista's current S&P corporate credit rating is BBB. We believe operating at a corporate credit rating level (senior unsecured) of BBB+ is comparable with other US utilities providing both electricity and natural gas. As shown in Illustration No. 7, the average credit rating for U.S. Regulated Combined Gas and Electric Utilities is BBB+.

Illustration No. 7:



We expect that a continued focus on the regulated utility, conservative financing strategies and a supportive regulatory environment will contribute toward an upgrade to a BBB+ corporate credit rating for Avista. Operating with a BBB+ credit rating would likely attract additional investors, lower our debt pricing for future financings, and make us more competitive with other utilities. In addition, financially healthy utilities are better able to invest in the required infrastructure over time to serve their customers, and to withstand the challenges facing the industry and potential financial market disruptions.

Q. How important is the regulatory environment in which the Company operates?

A. Both Moody’s and S&P cite the regulatory environment in which a regulated utility operates as the dominant qualitative factor to determine a company’s creditworthiness. Moody's rating methodology is based on four primary factors. Two of those factors – a utility's "regulatory framework" and its "ability to recover costs and earn returns" – make up 50 percent of Moody's rating methodology[5].

S&P states the following[6]:

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Because of the major capital expenditures planned by Avista and future maturities of long-term debt, a supportive regulatory environment is essential in maintaining our current credit rating.

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

A. Yes.

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[5]Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013.
[6]Standard and Poor's, Key Credit Factors: Business and Financial Risks in the Investor-owned Utility Industry, March 2010.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

MARK T. THIES
Exhibit No. 201

Financial Overview, Capital Structure and Overall Rate of Return

AVISTA CORPORATION

Long-term Securities Credit Ratings

	Standard & Poor's		Moody's	
Last Upgraded	March/August 2011[1]		January 2014 [2]	
Credit Outlook	Stable		Stable	
	A+		**A1**	
	A		**A2**	First Mortgage Bonds Secured Medium-Term Notes
	A-	First Mortgage Bonds Secured Medium-Term Notes	**A3**	
	BBB+		**Baa1**	Avista Corp./Issuer rating
	BBB	Avista Corp./Corporate credit rating	**Baa2**	Trust-Originated Preferred Securities
	BBB-		**Baa3**	
	INVESTMENT GRADE			
	BB+	Trust-Originated Preferred Securities	**Ba1**	
	BB		**Ba2**	
	BB-		**Ba3**	

(1) The Company received an upgrade from Standard & Poor's to its Corporate credit rating in March 2011 and to its First Mortgage Bonds in August 2011.

(2) The Company received upgrades from Moody's Investors Service in January 2014. The upgrades were one level for First Mortgage Bonds and the Issuer Rating and two levels for Trust-Originated Preferred Securities.

AVISTA CORPORATION
Proposed Cost of Capital
December 31, 2016

	Forecast Amount	Percent of Total Capital	Proposed Structure	Cost	Component Cost
Total Debt	$ 1,573,000,000	50.14%	50.0%	5.53%	2.77%
Common Equity	$ 1,563,927,000	49.86%	50.0%	9.90% (1)	4.95%
Total	$ 3,136,927,000	100.00%	100.0%		**7.72%**

AVISTA CORPORATION
Embedded Cost of Capital
December 31, 2014

	Amount	Percent of Total Capital	Cost	Component Cost
Total Debt	$ 1,393,000,000	49.60%	5.46%	2.71%
Common Equity	$ 1,415,264,000	50.40%	9.65% (2)	4.86%
TOTAL	$ 2,808,264,000	100.00%		**7.57%**

(1) Proposed return on common equity
(2) Last approved ROE as of 12/31/2014.

AVISTA CORPORATION
Cost of Long-Term Debt Detail - Oregon
December 31, 2016

Line No.	Description	Coupon Rate	Maturity Date	Settlement Date	Principal Amount	Issuance Costs	Settled IR Hedges Loss/(Gain)	Discount (Premium)	Loss/Reacq Expenses	Net Proceeds	Yield to Maturity	Outstanding 12-31-2016
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)	(h)	(i)	(j)	(k)
1	FMBS - SERIES A	7.530%	05-05-2023	05-06-1993	5,500,000	42,712	-	-	963,011	4,494,277	9.359%	5,500,000
2	FMBS - SERIES A	7.540%	05-05-2023	05-07-1993	1,000,000	7,766	-	-	175,412	816,822	9.375%	1,000,000
3	FMBS - SERIES A	7.390%	05-11-2018	05-11-1993	7,000,000	54,364	-	-	1,227,883	5,717,753	9.287%	7,000,000
4	FMBS - SERIES A	7.450%	06-11-2018	06-09-1993	15,500,000	120,377	-	50,220	2,140,440	13,188,963	8.953%	15,500,000
5	FMBS - SERIES A	7.180%	08-11-2023	08-12-1993	7,000,000	54,364	-	-	-	6,945,636	7.244%	7,000,000
6	ADVANCE ASSOCIAT [1]	2.338% [7]	06-01-2037	06-03-1997	40,000,000	1,296,086	-	-	(1,769,125)	40,473,039	2.293%	40,000,000
7	Series C Setup C	N/A	06-15-2013	06-15-1998	-	666,169	-	-	-	-		
8	FMBS - SERIES	6.370%	06-19-2028	06-19-1998	25,000,000	158,304	-	-	188,649	24,653,047	6.475%	25,000,000
9	5.45% SERIES	5.450%	12-01-2019	11-18-2004	90,000,000	1,192,681	-	239,400	-	88,567,919	5.608%	90,000,000
10	FMBS - 6.25%	6.250%	12-01-2035	11-17-2005	150,000,000	1,812,935	(4,445,000)	367,500	-	152,264,565	6.139%	150,000,000
11	FMBS - 5.70%	5.700%	07-01-2037	12-15-2006	150,000,000	4,702,304	3,738,000	222,000	-	141,337,696	6.120%	150,000,000
12	5.95% SERIES	5.950%	06-01-2018	04-03-2008	250,000,000	2,246,419	16,395,000	835,000	-	230,523,581	7.034%	250,000,000
13	5.125% SERIES	5.125%	04-01-2022	09-22-2009	250,000,000	2,284,788	(10,776,222)	575,000	2,875,817	255,040,618	4.907%	250,000,000
14	3.89% SERIES	3.890%	12-20-2020	12-20-2010	52,000,000	385,129	-	-	6,273,664	45,341,207	5.578%	52,000,000
15	5.55% SERIES	5.550%	12-20-2040	12-20-2010	35,000,000	258,834	-	-	5,263,822	29,477,345	6.788%	35,000,000
16	4.45% SERIES	4.450%	12-14-2041	12-14-2011	85,000,000	692,833	10,557,000	-	-	73,750,167	5.340%	85,000,000
17	4.23% SERIES	4.230%	11-29-2047	11-30-2012	80,000,000	730,833	18,546,870	-	105,020	60,617,277	5.868%	80,000,000
18	4.11% SERIES	4.110%	12-01-2044	12-18-2014	60,000,000	425,188 [4]	(5,429,000)	-	-	65,003,808	3.650%	60,000,000
19	Forecasted issuance [2]	3.750% [8]	10-01-2045	10-01-2015	100,000,000	1,000,000 [3]				98,999,997	3.806%	100,000,000
20	Forecasted issuance [2]	4.000% [8]	10-01-2046	10-01-2016	170,000,000	1,700,000 [3]				168,299,997	4.058%	170,000,000
21												1,573,000,000
22												
23	Repurchase [5]	7.74%	12-31-2017	06-30-2006	6,875,000				483,582	6,391,418	8.721%	
24	Repurchase [5]	5.72%	03-01-2034	12-30-2009	17,000,000				1,916,297	15,083,703	6.661%	
25	Repurchase [5]	6.55%	10-01-2032	12-31-2008	66,700,000				3,709,174	62,990,826	7.034%	
26	**OREGON TOTAL DEBT OUTSTANDING AND COST OF DEBT AT December 31, 2016**											1,573,000,000
27												
28								**Adjusted Weighted Average Cost of Debt**			**5.53%**	
29												
30												
31		[1] Average Monthly Average Rate over a twelve month period										
32		[2] Forecasted issuance pursuant to the Company's internal forecast										
33		[3] The Company forecast issuance expenses of 1% based on historical costs										
34		[4] Includes issuance costs through Feb. 2015										

AVISTA CORPORATION

Cost of Long-Term Variable Rate Debt Detail

December 31, 2016

	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Avg of
(a)	(b)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(o)
Trust Preferred*	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	**$ 40,000,000**
Number of Days in Month	31	31	29	31	30	31	30	31	31	30	31	30	31	
Forecasted Rates Trust Preferred**	1.6555%	1.8578%	1.8578%	1.8578%	2.0742%	2.0742%	2.0742%	2.2650%	2.2650%	2.2650%	2.4373%	2.4373%	2.4373%	
Trust Preferred Interest Expense	$ 57,023	$ 63,991	$ 59,862	$ 63,991	$ 69,140	$ 71,445	$ 69,140	$ 78,017	$ 78,017	$ 75,500	$ 83,951	$ 81,243	$ 83,951	**$ 935,271**

Description	Coupon Rate	Maturity Date	Settlement Date	Principal Amount	Issuance Costs	Loss/Reacq Expenses	Net Proceeds	Yield to Maturity	Outstanding 12-31-2016	Effective Cost
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Trust Preferred	2.338%	06-01-2037	06-03-1997	$ 40,000,000	$ 1,296,086	$ (1,769,125)	$ 40,473,039	2.293%	$ 40,000,000	$ 917,139

*Original issue principal amount was $50 million. The Company repurchased $10 million of the securities outstanding.

**Forecasted Rates are based on forward rates from Thomson Reuters analysis tools plus the 87.5 basis points pursuant to the debt agreement.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

MARK T. THIES
Exhibit No. 202

Financial Overview, Capital Structure and Overall Rate of Return

CONFIDENTIAL

Interest Rate Risk Management Plan

Pages 1 through 8

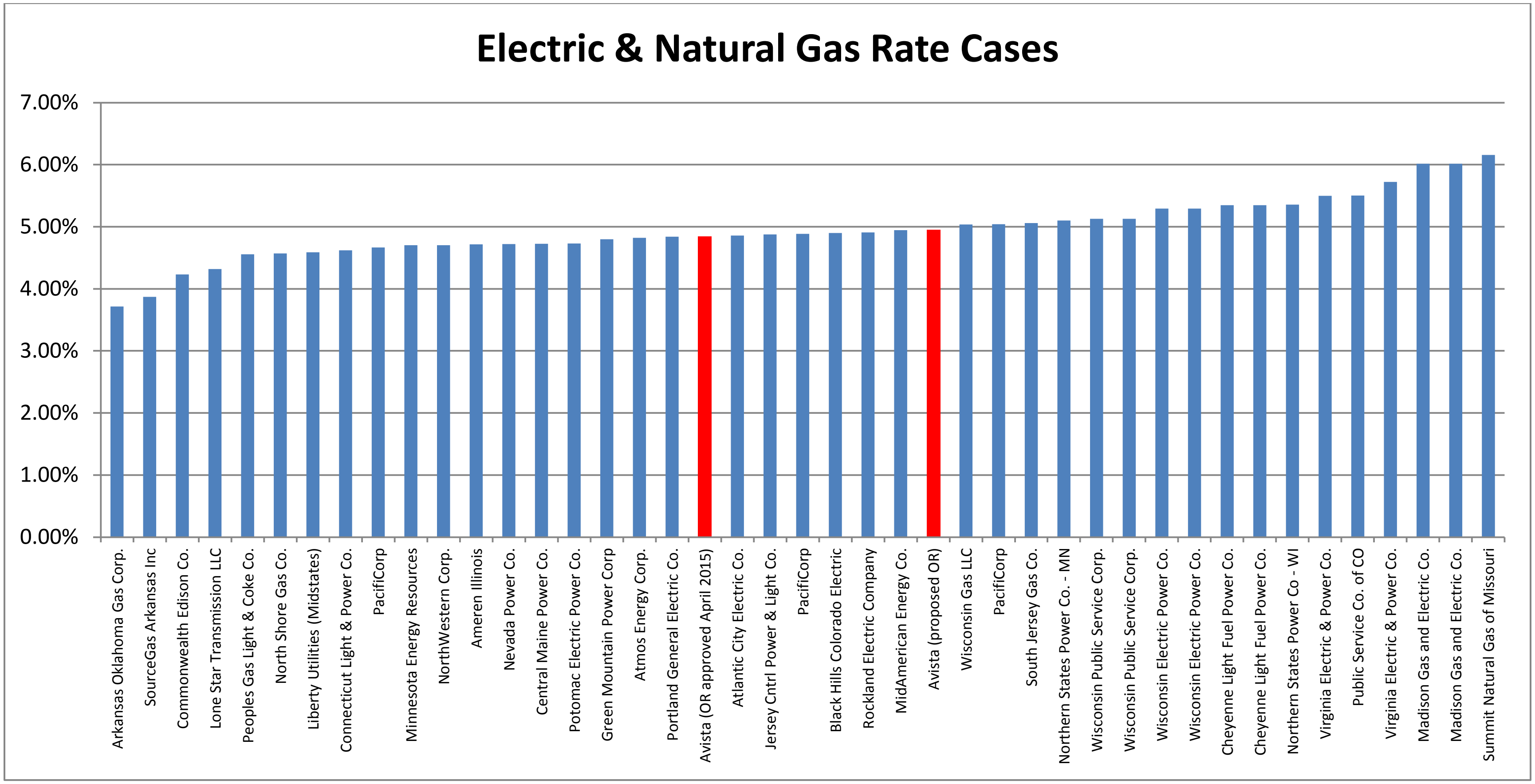
BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

MARK T. THEIS

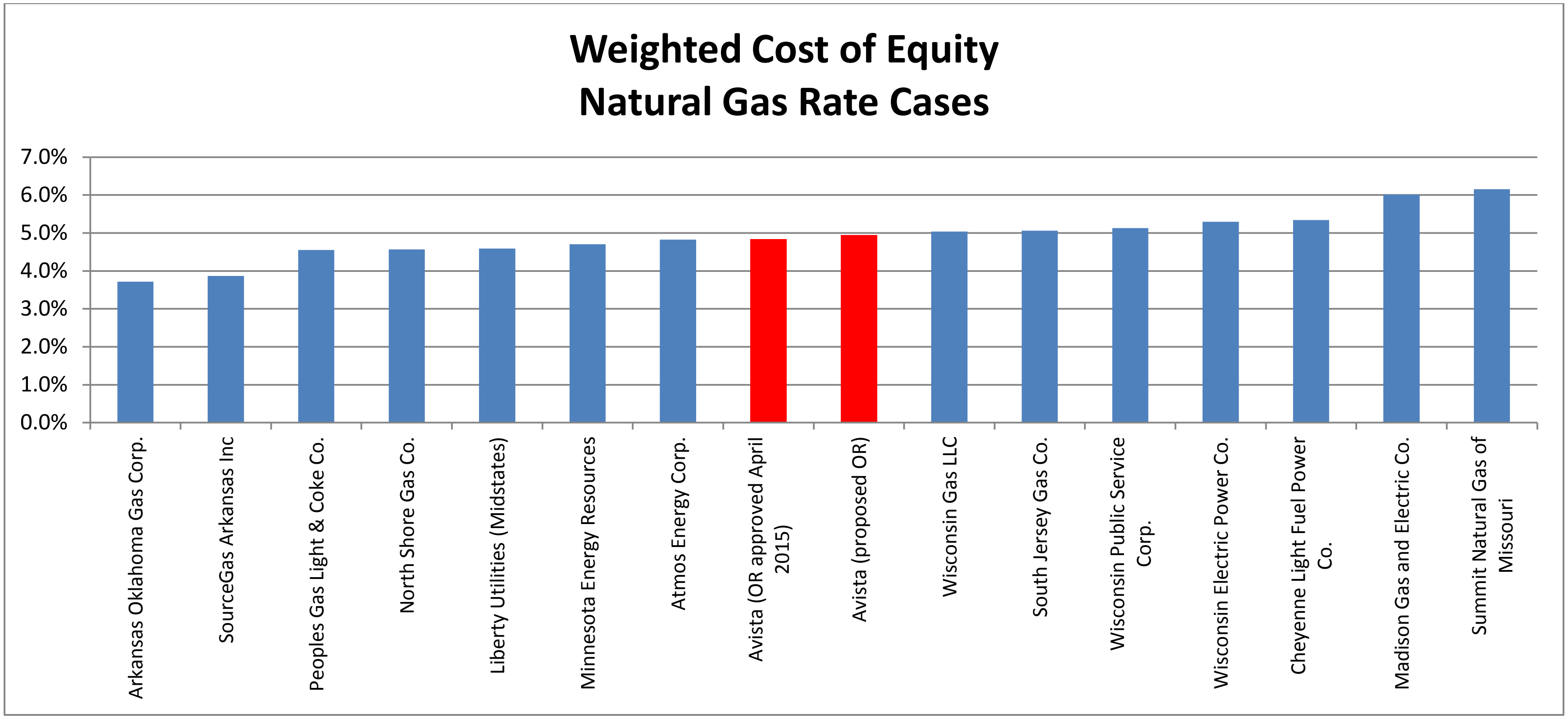
Exhibit No. 203

Financial Overview, Capital Structure and Overall Rate of Return



*Source: SNL Financial. Rate Cases finalized July 1, 2014 through March 31, 2015.
Items added (red bars):

- Avista's April 2015 approved return from the Oregon Commission.
- Avista's proposed return in the current filing.



*Source: SNL Financial. Natural Gas Rate Cases finalized July 1, 2014 through March 31, 2015.
Items added (red bars):

- Avista's April 2015 approved return from the Oregon Commission.
- Avista's proposed return in the current filing.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

MARK T. THIES
Exhibit No. 204

Financial Overview, Capital Structure and Overall Rate of Return

CONFIDENTIAL

Planned capital expenditures and long-term debt issuances

Pages 1 of 1

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF ADRIEN M. MCKENZIE

REPRESENTING AVISTA CORPORATION

Return on Equity

DIRECT TESTIMONY OF ADRIEN M. MCKENZIE

TABLE OF CONTENTS

I. INTRODUCTION 2
II. RETURN ON EQUITY FOR AVISTA 4
III. OUTLOOK FOR CAPITAL COSTS 11
IV. SELECTION OF PROXY GROUPS 19
  A. Gas and Combination Utility Proxy Groups 20
  B. Capital Structure 23
V. CAPITAL MARKET ESTIMATES 25
  A. Economic Standards 26
  B. Discounted Cash Flow Analyses 29
  C. Empirical Capital Asset Pricing Model 41
  D. Utility Risk Premium 46
  E. Flotation Costs 51
VI. OTHER ROE BENCHMARKS 54
  A. Capital Asset Pricing Model 54
  B. Expected Earnings Approach 55
  C. Low Risk Non-Utility DCF 58
VII. IMPACT OF REGULATORY MECHANISMS 62

EXHIBIT NO. 301:

Schedule AMM-1 Summary of Results
Schedule AMM-2 Capital Structure
Schedule AMM-3 DCF Model – Gas Group
Schedule AMM-4 Sustainable Growth Rate – Gas Group
Schedule AMM-5 DCF Model – Combination Group
Schedule AMM-6 Sustainable Growth Rate – Combination Group
Schedule AMM-7 Empirical CAPM – Gas Group
Schedule AMM-8 Empirical CAPM – Combination Group
Schedule AMM-9 Gas Utility Risk Premium
Schedule AMM-10 CAPM – Gas Group
Schedule AMM-11 CAPM – Combination Group
Schedule AMM-12 Expected Earnings Approach
Schedule AMM-13 DCF Model – Non-Utility Group
Schedule AMM-14 Proxy Group Regulatory Mechanisms

EXHIBIT NO. 302: Qualifications of Adrien M. McKenzie

I. INTRODUCTION

Q. Please state your name and business address.

A. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am a Vice President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and professional experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit No. 302.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present to the Public Utility Commission of Oregon ("OPUC") my independent evaluation of the 9.9 percent fair rate of return on equity ("ROE") that Avista Corp. ("Avista" or "the Company") is requesting for its jurisdictional gas utility operations. In addition, I also examined the reasonableness of the Company's requested capital structure, considering both the specific risks faced by Avista and other industry guidelines.

Q. Please summarize the information and materials you relied on to support the opinions and conclusions contained in your testimony.

A. I am familiar with the organization, finances, and operations of Avista from my participation in prior proceedings before the OPUC, Washington Utilities and Transportation Commission ("WUTC"), and the Idaho Public Utilities Commission ("IPUC"). In connection with the present filing, I considered and relied upon publicly available financial reports and filings, and other published information relating to Avista. I also reviewed information relating generally to current capital market conditions and specifically to current investor perceptions, requirements, and expectations for Avista's gas utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for Avista, and they form the basis of my analyses and conclusions.

Q. How is your testimony organized?

A. After first summarizing my conclusions and recommendations, I briefly review Avista's operations and finances. I then present current conditions in the capital markets and their implications in evaluating a fair ROE for Avista. With this as a background, I discuss well-accepted quantitative analyses to estimate the current cost of equity for separate reference groups of natural gas and combination natural gas and electric utilities. I based my ROE recommendations on the results of the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on allowed ROEs for gas utilities, which are all methods that are commonly relied on in regulatory proceedings. Considering the cost of equity estimates indicated by my analyses, the reasonableness of Avista's requested 9.9 percent ROE was evaluated taking into account the specific risks for its jurisdictional utility operations in Oregon, Avista's requirements for financial strength that provides benefits to customers, as well as flotation costs, which are properly considered in setting a fair ROE.

In addition, I tested my conclusions against alternative checks of reasonableness, which included applications of the traditional Capital Asset Pricing Model ("CAPM"), reference to expected rates of return and allowed ROEs, and application of the DCF model to a select group of low risk non-utility firms. Finally, my testimony addresses the impact of regulatory mechanisms on an evaluation of a fair ROE for Avista.

Q. What is the role of the ROE in setting a utility's rates?

A. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a fair and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the U.S. Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but they can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

II. RETURN ON EQUITY FOR AVISTA

Q. What is the purpose of this section?

A. This section presents my conclusions regarding the reasonableness of the 9.9 percent ROE requested by Avista for its jurisdictional gas utility operations. This section also

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

Q. Please summarize the results of your analyses.

A. My ROE recommendations are based on the results of three primary methods – the DCF model, the ECAPM, and the risk premium approach. The cost of common equity estimates produced by these three primary analyses are presented on page 1 of Schedule AMM-1, and summarized in Table No. 1, below:

Table No. 1:

SUMMARY OF PRIMARY METHODS

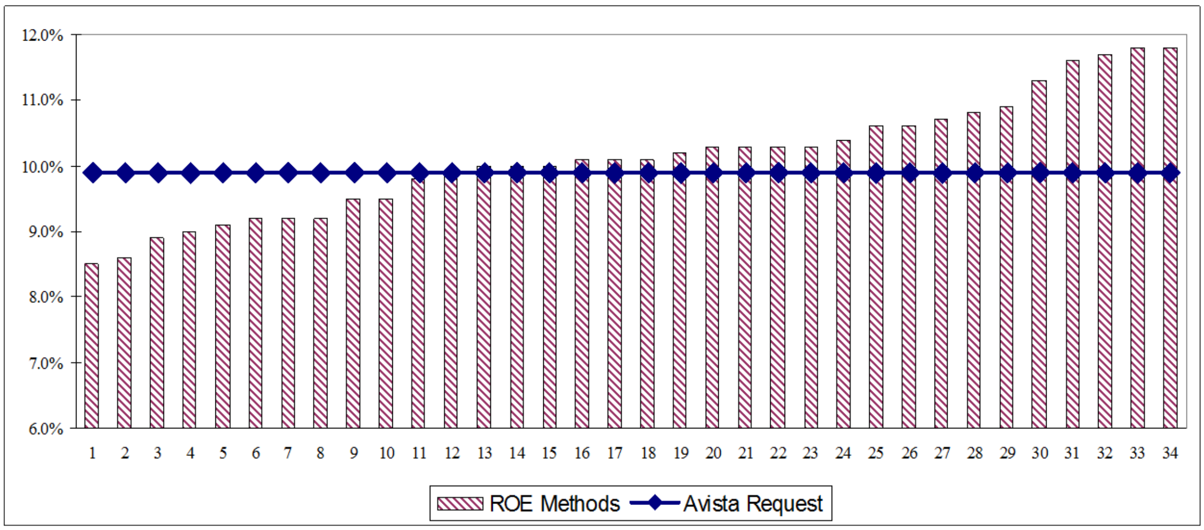
	Gas Group		Combination Group	
DCF	Average	Midpoint	Average	Midpoint
Value Line	10.3%	10.7%	10.0%	10.1%
IBES	9.5%	10.3%	9.1%	9.2%
Zacks	8.6%	8.9%	9.0%	9.2%
Internal br + sv	9.5%	10.3%	8.5%	9.2%
Empirical CAPM - Current Bond Yield				
Unadjusted	10.1%	10.0%	9.8%	9.9%
Size Adjusted	11.6%	11.7%	10.6%	10.6%
Empirical CAPM - Projected Bond Yield				
Unadjusted	10.4%	10.3%	10.0%	10.2%
Size Adjusted	11.8%	11.8%	10.9%	10.8%
Utility Risk Premium				
Current Bond Yields	10.1%		--	
Projected Bond Yields	11.3%		--	

	Cost of Equity Recommendation		
Cost of Equity Range	**9.5%**	**--**	**10.8%**
Flotation Cost Adjustment			
Dividend Yield	3.2%		3.2%
Flotation Cost Percentage	3.6%		3.6%
Adjustment	0.1%		0.1%
Recommended ROE Range	**9.6%**	**--**	**10.9%**

Illustration No. 1, below, presents the 34 cost of equity estimates presented in Table No. 1 in rank order, and compares them with Avista's 9.9 percent ROE request:

<u>Illustration No. 1:</u>

RESULTS OF ANALYSES VS. AVISTA REQUEST



Q. What are your findings regarding the 9.9 percent ROE requested by Avista?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital under reasonable terms, I determined that 9.9 percent is a conservative estimate of investors' required ROE for Avista. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with Avista's jurisdictional utility operations, my analyses focused on two proxy groups of firms with gas utility operations;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, ECAPM, and risk premium methods to estimate a fair ROE for Avista;
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for Avista's gas utility operations is in the **9.5 percent to 10.8 percent** range,

or **9.6 percent to 10.9 percent** after incorporating an adjustment to account for the impact of common equity flotation costs;

- As reflected in the testimony of Mark T. Thies, Avista is requesting a fair ROE of **9.9 percent**, which falls below the **10.25 percent** midpoint of my recommended range. Considering capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that 9.9 percent represents a conservative ROE for Avista; and,
- Because the utilities in my proxy groups operate under a wide variety of regulatory mechanisms, including decoupling, the mitigation in risks associated with Avista's requested decoupling mechanism is already reflected in the results of my analyses, and no separate adjustment to the Company's ROE is necessary or warranted.

Q. Did you evaluate other checks of reasonableness?

A. Yes. I also performed alternative tests to confirm the results of my primary methods and my conclusions as to a fair and reasonable ROE for Avista. The results of these alternative ROE benchmarks are presented on page 2 of Schedule AMM-2, and summarized in Table No. 2, below:

Table No. 2:

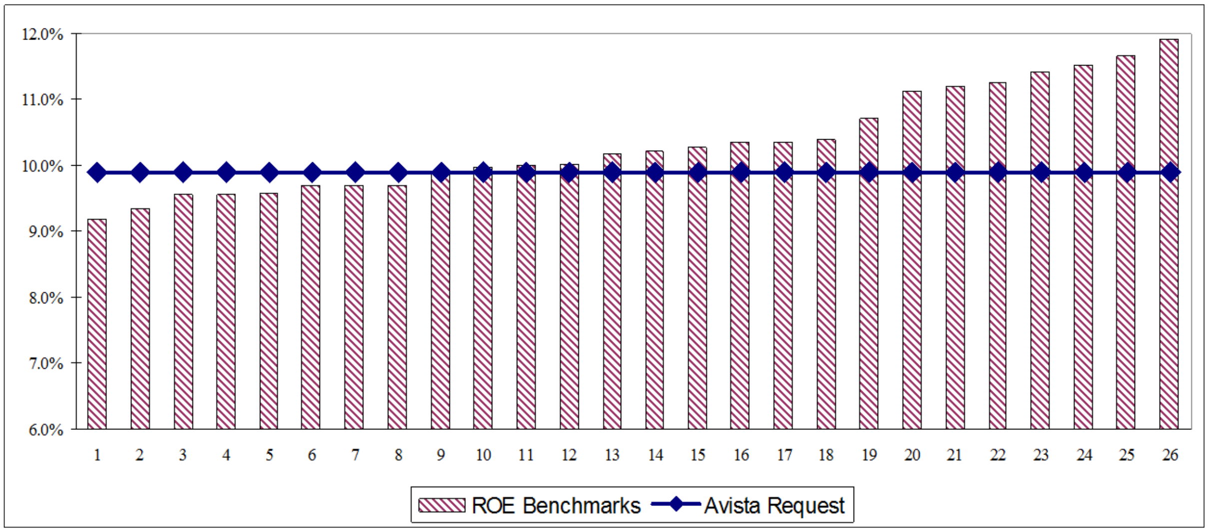
SUMMARY OF ROE BENCHMARKS

	Gas Group		Combination Group	
	Average	**Midpoint**	**Average**	**Midpoint**
CAPM - Current Bond Yield				
Unadjusted	9.7%	9.6%	9.2%	9.4%
Size Adjusted	11.1%	11.2%	10.0%	10.0%
CAPM - Projected Bond Yield				
Unadjusted	10.0%	9.9%	9.6%	9.7%
Size Adjusted	11.4%	11.5%	10.4%	10.4%
Expected Earnings - Gas Group	11.3%	11.9%	10.7%	11.7%
Non-Utility DCF				
Value Line	10.3%	10.4%		
IBES	9.6%	9.7%		
Zacks	10.2%	10.2%		

Illustration No. 2, below, presents these 26 alternative benchmark results presented in Table No. 2 in rank order, and compares them with Avista's 9.9 percent ROE request:

<u>Illustration No. 2:</u>

ALTERNATIVE ROE BENCHMARKS VS. AVISTA REQUEST



As summarized below, these results confirm the conclusion that the 9.9 percent ROE requested for Avista is conservative:

- Applying the traditional CAPM approach implied a current cost of equity on the order of 9.2 percent to 11.1 percent;
- Expected returns for gas and combination utilities suggested an ROE range of 10.7 percent to 11.7 percent, excluding any adjustment for flotation costs; and,
- DCF estimates for a low-risk group of non-utility firms resulted in average cost of equity estimates of 9.6 percent to 10.3 percent.

These tests of reasonableness confirm that a 9.9 percent ROE falls in the lower end of the reasonable range to maintain Avista's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

Q. What other factors should be considered in evaluating the ROE requested by Avista in this case?

A. Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting the Company's financial position so that Avista remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of continuing to build the Company's financial strength in order to attract the capital needed to secure reliable service at a lower cost for customers. The reasonableness of the Company's requested ROE is reinforced by the fact that, due to broad-based expectations for higher bond yields, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. How do the Commission's actions impact investors' confidence and required rates of return?

A. Regulatory signals are a major driver of investors' risk assessment for utilities. Security analysts study commission orders and regulatory policy statements to advise investors where to put their money. If OPUC actions instill confidence that the regulatory environment is supportive, investors make capital available to Oregon's utilities on more reasonable terms. When investors are confident that a utility has supportive regulation, they will make funds available even in times of turmoil in the financial markets.

Q. Is it widely accepted that a utility's ability to attract capital must be considered in establishing a fair rate of return?

A. Yes. This is a fundamental standard underlying the regulation of public utilities. The Supreme Court's *Bluefield* and *Hope* decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and that, if the utility is efficient and prudent on a prospective basis, it will be able to maintain and support its credit and have the opportunity to raise necessary capital.[3]

Q. Does an ROE of 9.9 percent represent a reasonable cost for Avista's customers to pay?

A. Yes. Investors have many options vying for their money. They make investment capital available to Avista only if the expected returns justify the risk. Customers will enjoy reliable and efficient service so long as investors are willing to make the capital investments necessary to maintain and improve Avista's utility system. Providing an adequate return to investors is a necessary cost to ensure that capital is available to Avista now and in the future. If regulatory decisions increase risk or limit returns to levels that are insufficient to justify the risk, investors will look elsewhere to invest capital.

Q. What is your conclusion as to the reasonableness of Avista's requested capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of 50.0 percent represents a reasonable capitalization for Avista. This conclusion was based on the following findings:

- The common equity ratio implied by Avista's capital structure falls within the range of capitalizations maintained by the proxy groups of utilities based on data at year-end 2014 and near-term expectations;
- Avista's 50.0 percent common equity ratio falls below the 51.4 percent average for the proxy group of gas utilities at year-end 2014. Similarly, Avista's requested equity ratio falls short of the 55.9 percent equity ratio based on Value Line's expectations for these utilities over the near-term.

[3] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*"); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

Because a capitalization that contains relatively more debt leverage implies greater financial risk, it also implies a higher required rate of return to compensate investors for bearing additional uncertainty; and,

- Avista's requested capitalization is consistent with the Company's need to maintain its credit standing and financial flexibility as it seeks to raise additional capital to fund significant system investments, refinance maturing debt, and meet the requirements of its service territory.

Q. What are the implications of setting an allowed ROE below the returns available from other investments of comparable risk?

A. If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both of these outcomes violate regulatory standards.

III. OUTLOOK FOR CAPITAL COSTS

Q. Do current capital market conditions provide a representative basis on which to evaluate a fair ROE?

A. No. Current capital market conditions continue to reflect the Federal Reserve's unprecedented monetary policy actions in the aftermath of the Great Recession, and are not representative of what investors expect in the future. Investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. In response to heightened uncertainties in recent years, investors have repeatedly sought a safe haven in U.S. government bonds. As a result of this "flight to safety," Treasury bond yields have been pushed significantly lower in the face of political, economic, and capital market risks. In addition, the Federal Reserve has implemented measures designed to push interest rates to historically low levels in an effort to stimulate the economy and bolster employment.

Q. How do current yields on public utility bonds compare with what investors have experienced in the past?

A. The yields on utility bonds remain near their lowest levels in modern history. Illustration No. 3, below, compares the February 2015 average yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

<u>Illustration No. 3:</u>

BBB UTILITY BOND YIELDS

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience. Similarly, while 10-year Treasury bond yields may reflect a modest increase from all-time lows less than 2.0

percent,[4] they are hardly comparable to historical levels.[5] Federal Reserve President Charles Plosser recently observed that U.S. interest rates are unprecedentedly low, and "outside historical norms."[6]

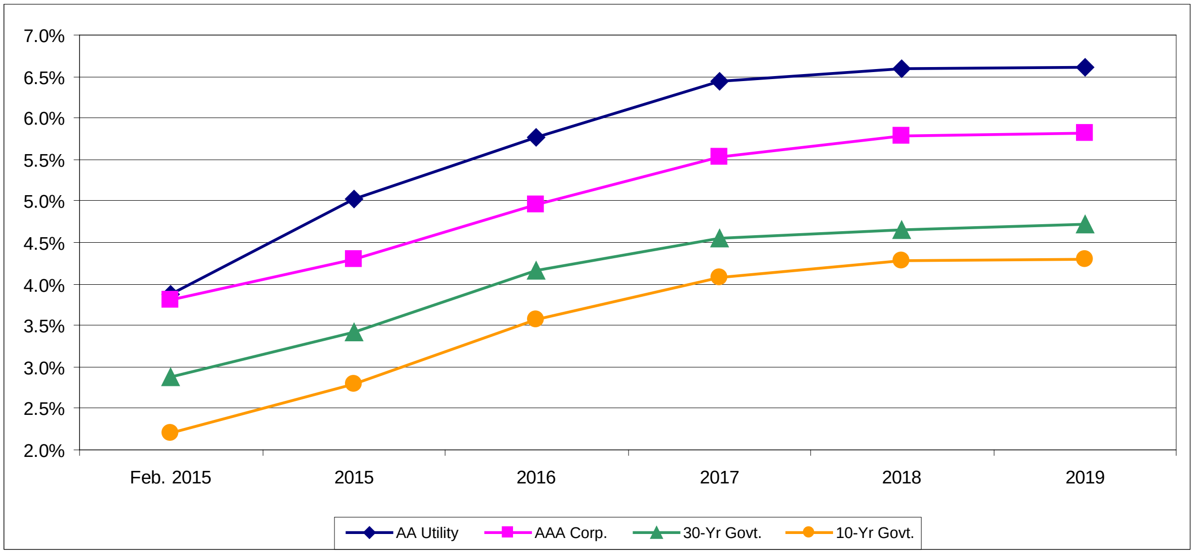
Q. Are these very low interest rates expected to continue?

A. No. Investors continue to anticipate that interest rates will increase significantly from present levels. Illustration No. 4 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

[4] The average yield on 10-year Treasury bonds for the six-months ended February 2015 was 2.21 percent.
[5] Over the 1968-2014 period illustrated on Illustration No. 3, 10-year Treasury bond yields averaged 6.73 percent.
[6] Barnato, Katy, "Fed's Plosser: Low rates 'should make us nervous'," *CNBC* (Nov. 11, 2014).

ILLUSTRATION NO. 4:

INTEREST RATE TRENDS



Source:

Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015)
IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014)
Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014)

These forecasting services are highly regarded and widely referenced, with FERC incorporating forecasts from IHS Global Insight and the EIA in its preferred DCF model for natural gas and oil pipelines, as well as for electric transmission utilities. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2015-2019 period.

Q. Do recent actions of the Federal Reserve support the contention that current low interest rates will continue indefinitely?

A. No. Citing improvement in the outlook for the labor market and increasing strength in the broader economy, the Federal Reserve elected to discontinue further purchases under its bond-buying program at its October 2014 meeting. While the Federal Reserve continues to express support for maintaining a highly accommodative monetary policy and an exceptionally low target range for the federal funds rate, elimination of additional bond purchases under the Federal Reserve's program of "Quantitative Easing" should ultimately exert upward pressure on long-term interest rates. As *The Wall Street Journal* observed:

> The Fed's decision to begin trimming its $85 billion monthly bond-buying program is widely expected to result in higher medium-term and long-term market interest rates. That means many borrowers, from home buyers to businesses, will be paying higher rates in the near future.[7]

While the Federal Reserve's conclusion of new asset purchases has moderated uncertainties over just when, and to what degree, the stimulus program would be altered, investors continue to face ongoing uncertainties over future modifications that could ultimately affect how quickly and by how much interest rates are affected.

Q. Does the cessation of further asset purchases by the Federal Reserve mark a return to "normal" in capital markets?

A. No. The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400 - $500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and their effect on capital market conditions became more pronounced. Table No. 3 below charts the course of the Federal Reserve's asset purchase program:

[7] Hilsenrath, Jon, "Fed Dials Back Bond Buying, Keeps a Wary Eye on Growth," *The Wall Street Journal* at A1 (Dec. 19, 2013).

Table No. 3:

FEDERAL RESERVE BALANCES OF
TREASURY BONDS AND MORTGAGE-BACKED SECURITIES
(Billion $)

2008	$ 410
2009	$ 1,618
2010	$ 1,939
2011	$ 2,423
2012	$ 2,512
2013	$ 3,597
2014	$ 4,097

Far from representing a return to normal, the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities now amount to more than $4 trillion,[8] which is an all-time high.

For now, the Federal Reserve is maintaining its policy of reinvesting principal payments from these securities – about $16 billion a month – and rolling over maturing securities at auction. As the Federal Reserve recently noted:

> The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.[9]

This continued investment maintains the downward pressure on interest rates that is the hallmark of the stimulus program and the anomalous conditions currently characterizing capital markets.

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[8] *Federal Reserve Statistical Release*, "Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks," H.4.1.
[9] *Press Release*, Board of Governors of the Federal Reserve System, (Mar. 18, 2015), http://www.federalreserve.gov/newsevents/press/monetary/20150318a.htm.

Of course, the corollary to these observations is that changes to this policy of reinvestment would further reduce stimulus measures and could place significant upward pressure on bond yields, especially considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. The International Monetary Fund noted, "A lack of Fed clarity could cause a major spike in borrowing costs that could cause severe damage to the U.S. recovery and send destructive shockwaves around the global economy," adding that, "[a] smooth and gradual upward shift in the yield curve might be difficult to engineer, and there could be periods of higher volatility when longer yields jump sharply—as recent events suggest."[10] As a Financial Analysts Journal article noted:

> Because no precedent exists for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is also vast. . . . Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.[11]

These developments highlight continued concerns for investors and support expectations for higher interest rates as the economy and labor markets continue to recover. With the Federal Reserve curtailing the expansion of its enormous portfolio of Treasuries and mortgage bonds, ongoing concerns over political stalemate in Washington, the threat of renewed recession in the Eurozone, uncertainties over the impact of falling oil prices, and political and economic instability in Ukraine, the Middle East, and emerging markets, the potential for significant volatility and higher capital costs is clearly evident to investors.

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[10] Talley, Ian, "IMF Urges 'Improved' U.S. Fed Policy Transparency as It Mulls Easy Money Exit," *The Wall Street Journal* (July 26, 2013).
[11] Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," *Financial Analysts Journal* (November/December 2013).

Q. Have other regulators recognized the importance of considering the implications of current capital market conditions when evaluating a fair ROE for a utility?

A. Yes. In its June 19, 2014 order in Docket No. EL11-66-001, FERC explicitly noted the need to "consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns."[12] FERC ultimately determined that due to unrepresentative capital market conditions, an upward adjustment to the 9.39 percent midpoint of its DCF range was required in order to meet the regulatory standards established by *Hope* and *Bluefield*. Based on its examination of alternatives to the DCF approach, FERC authorized an ROE from the upper end of its DCF range, or 10.57 percent.[13]

Q. What do these events imply with respect to the ROE for Avista more generally?

A. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets and ongoing economic and political risks. As a result, current capital costs are not representative of what is likely to prevail over the near-term future. As FERC recently concluded:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of

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[12] *Martha Coakley et al., v. Bangor Hydro-Electric Company, et al.,* Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014) ("Opinion No. 531").
[13] *Id.* at PP 145, 146, 148, & 152.

> return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses …[14]

This conclusion is supported by comparisons of current conditions to the historical record and independent forecasts. As demonstrated earlier, recognized economic forecasting services project that long-term capital costs will increase from present levels.

Given investors' expectations for rising interest rates and capital costs, the OPUC should consider near-term forecasts for public utility bond yields in assessing the reasonableness of individual cost of equity estimates and in evaluating a fair ROE for Avista from within the range of reasonableness. The use of these near-term forecasts for public utility bond yields is supported below by economic studies that show that equity risk premiums are higher when interest rates are at very low levels.

IV. SELECTION OF PROXY GROUPS

Q. How did you implement quantitative methods to estimate the cost of common equity for Avista?

A. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods such as the DCF and ECAPM to a proxy group of publicly traded companies that investors regard as risk-comparable.

[14] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

A. Gas and Combination Utility Proxy Groups

Q. What specific proxy groups of utilities did you rely on for your analysis?

A. In order to reflect the risks and prospects associated with Avista's jurisdictional gas utility operations, I examined quantitative estimates of investors' required ROE for a group of natural gas utilities, consisting of ten publicly traded firms included in Value Line's Natural Gas Utility industry.[15] I refer to these utilities as the "Gas Group."

Q. What other proxy group of utilities did you consider in your analyses?

A. My analyses also considered those utilities followed by Value Line with both electric and gas utility operations. In addition, I excluded seven firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because of current involvement in a major merger or acquisition.[16] These criteria resulted in a proxy group composed of twenty-one companies, which I will refer to as the "Combination Group."

Q. How did you evaluate the investment risks of the proxy groups?

A. My evaluation of relative risk considered four objective, published benchmarks that are widely relied on in the investment community. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default).[17] Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a

[15] I excluded one firm (UGI Corporation) that was included in Value Line's Natural Gas Utility Industry because it is primarily engaged in propane sales and marketing.

[16] Exelon Corporation, Integrys Energy Group, Pepco Holdings, PPL Corporation, TECO Energy, UIL Holdings Corporation, and Wisconsin Energy.

[17] Credit rating firms, such as S&P, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'AAA', 'AA', 'A', and 'BBB' ratings are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term "investment grade" refers to bonds with ratings in the 'BBB' category and above.

category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in New *Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors.… Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[18]

Q. What do these measures indicate with respect to the overall risks of the Gas and Combination Groups?

A. The average risk indicators for the proxy groups are shown in Table No. 4, below:

Table No. 4:

COMPARISON OF RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Gas Utility	A-	A3	2	A	0.79
Combination Utility	BBB+	Baa1	2	B++	0.73
Avista	**BBB**	**Baa1**	**2**	**A**	**0.8**

As displayed in Table No. 4, Avista is assigned a corporate credit rating of "BBB" by S&P and "Baa1" by Moody's, with the average corporate credit ratings for the Gas Group

[18] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

indicating less risk. The average Safety Rank, Financial Strength Rating, and beta values for the Gas Group are essentially identical to Avista. With respect to the proxy group of combination utilities, Avista's BBB rating from S&P indicates slightly greater risk, as does the Company's higher beta. Avista's Financial Strength Rating suggests slightly lower risk than the Combination Group, with the Moody's credit rating and Value Line Safety Rank being identical.

Considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, and exposure to firm-specific factors, indicates that investors would likely conclude that the overall investment risks for Avista are generally comparable to those of the two proxy groups of utilities. As a result there is certainly no justification that would support a lower ROE for the Company than what is indicated based on my analyses for the proxy groups, and Avista's lower credit rating would suggest a higher cost of equity than for the group of gas utilities.

B. <u>Capital Structure</u>

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio is implicit in Avista's capital structure?

A. Avista's capital structure is presented in the testimony of Mr. Thies. As summarized in his testimony, the proposed common equity ratio used to compute Avista's overall rate of return is 50.0 percent in this filing.

Q. How does this compare to the average capitalization maintained by the Gas and Combination Groups?

A. As shown on page 1 of Exhibit No. 301, Schedule AMM-2, for the firms in the Gas Group, common equity ratios at December 31, 2014 averaged 51.4 percent of long-term capital, with Value Line expecting an average common equity ratio of 55.9 percent for its three-to-five year forecast horizon. Meanwhile, for the firms in the Combination Group, common equity ratios ranged from 30.2 percent to 62.3 percent and averaged 48.3 percent in 2014, while Value Line's near-term projected common equity ratios fell in a range of 34.5 percent to 65.0 percent and averaged 49.2 percent (page 2 of Exhibit No. 301, Schedule AMM-2). Thus, Avista's common equity ratio is within the range maintained by the Combination Group, while indicating somewhat greater financial risk than investors would associate with the Gas Group.

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Utilities, including Avista, are facing significant capital investment plans. Coupled with the potential for turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an uncertain environment. A conservative financial profile, in the form of a higher common equity ratio, is consistent with the need to accommodate these uncertainties and maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Q. What does this evidence suggest with respect to the Company's proposed capital structure?

A. Avista's capital structure is consistent with the range of industry benchmarks and reflects the Company's ongoing efforts to address the burden of significant capital expenditures, strengthen its credit standing, and support access to capital on reasonable terms, on a sustainable basis. Based on my evaluation, I concluded that Avista's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return.

V. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF, ECAPM, and risk premium analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. What role does the rate of return on common equity play in a utility's rates?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield* and *Hope* cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. What fundamental economic principle underlies the cost of equity concept?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders: they receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What does the above discussion imply with respect to estimating the cost of common equity for a utility?

A. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Did you rely on a single method to estimate the cost of equity for Avista?

A. No. In my opinion, no single method or model should be relied upon to determine a utility's cost of equity because no single approach can be regarded as wholly reliable. Therefore, I used the DCF, CAPM, and risk premium methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of equity pass fundamental tests of reasonableness and economic logic.

B. Discounted Cash Flow Analyses

Q. How is the DCF model used to estimate the cost of common equity?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The formula for the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q. What form of the DCF model is customarily used to estimate the cost of common equity in rate cases?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[19]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through the capital gains associated with price appreciation over the investors' holding period.

[19] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

Q. What form of the DCF model did you use?

A. I applied the constant growth DCF model to estimate the cost of common equity for Avista, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of common equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. How did you determine the dividend yield for the Gas Group?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Gas Group are presented on Exhibit No. 301, Schedule AMM-3. As shown on page 1, dividend yields for the firms in the Gas Group ranged from 2.4 percent to 3.9 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. Given that DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors, in the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratios falling significantly. As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

A measure that plays a pivotal role in determining investors' long-term growth expectations are future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. Do the growth rate projections of security analysts consider historical trends?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. Did Professor Myron J. Gordon, who originated the DCF approach, recognize the pivotal role that earnings play in forming investors' expectations?

A. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[20]

Q. Are analysts' assessments of growth rates appropriate for estimating investors' required return using the DCF model?

A. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment

[20] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications, as well as the continued success of services such as Thomson Reuters and Value Line, implies that investors use them as a basis for their expectations.

While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. <u>The accuracy of these forecasts in the sense of</u>

> whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[21]

Q. What are security analysts currently projecting in the way of growth for the firms in the Gas Group?

A. The earnings growth projections for each of the firms in the Gas Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on page 2 of Exhibit No. 301, Schedule AMM-3.[22]

Q. How else are investors' expectations of future long-term growth prospects often estimated when applying the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the Gas Group are summarized on page

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[21] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).

[22] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

2 of Exhibit No. 301, Schedule AMM-3, with the underlying details being presented on Exhibit No. 301, Schedule AMM-4.

Q. What cost of common equity estimates were implied for the Gas Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit No. 301, Schedule AMM-3.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate estimates that are extreme low or high outliers?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. How did you evaluate DCF estimates at the low end of the range?

A. I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[23] FERC recently affirmed that:

> The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[24]

Q. What interest rate benchmark did you consider in evaluating the DCF results for Avista?

A. As noted earlier, S&P has assigned a corporate credit rating of BBB to Avista, while Moody's has assigned the Company an issuer credit rating of Baa1. Companies rated "BBB-", "BBB", and "BBB+" by S&P or "Baa1", "Baa2", and "Baa3" by Moody's are all considered part of the triple-B rating category. Monthly yields on triple-B bonds reported by Moody's averaged approximately 4.6 percent over the six months ended February 2015.[25]

Q. What else should be considered in evaluating DCF estimates at the low end of the range?

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[23] *See, e.g., Southern California Edison Co.,* 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").
[24] *Martha Coakley et al., v. Bangor Hydro-Electric Company, et al.,* Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).
[25] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

A. As indicated earlier, while corporate bond yields have declined substantially as the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table No. 5 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of approximately 6.8 percent over the period 2015-2019:

Table No. 5:

IMPLIED BBB BOND YIELD

	2015-19
Projected AA Utility Yield	
IHS Global Insight (a)	6.10%
EIA (b)	6.08%
Average	6.09%
Current BBB - AA Yield Spread (c)	0.75%
Implied Triple-B Utility Yield	**6.84%**

(a) IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014)
(b) Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Sep. 2014 - Feb. 2015

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb more than 200 basis points through 2019.[26]

[26] *Blue Chip Financial Forecasts*, Vol. 33, No. 12 (Dec. 1, 2014).

Q. What does this test of logic imply with respect to the DCF results for the Gas Group?

A. Adding FERC's 100 basis-point premium to the historical and projected average utility bond yields implies a low-end threshold on the order of 5.6 percent to 7.8 percent. As highlighted on page 3 of Exhibit No. 301, Schedule AMM-3, after considering this test and the distribution of the individual estimates, I eliminated six low-end DCF estimates ranging from 4.9 percent to 6.9 percent. It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock.

Q. Is there a basis to eliminate high-end DCF values for the Gas Group?

A. No. While it is just as important to evaluate DCF estimates at the upper end of the range, there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values. In response, FERC has consistently applied a two-pronged test for high-end values based on the magnitude of the cost of equity estimate and its underlying growth rate. As FERC observed:

> The Presiding Judge found that the [utilities'] criteria for screening high-end outliers substantially complies with Commission precedent. . . The Presiding Judge further stated that the Commission's high-end outlier test since 2004 has been to exclude from the proxy group any company whose cost of equity estimate is at or above 17.7 percent and whose growth rate is at or above 13.3 percent.[27]

The upper end of the DCF range for the Gas Group was set by a cost of equity estimate of 13.5 percent. This cost of equity estimate, and the underlying growth rate of 10.0 percent, falls well below the threshold tests employed by FERC. Moreover, while this cost of equity estimate may exceed the majority of the remaining values, remaining low-end

[27] Opinion No. 531 at P 115 (footnotes omitted).

estimates in the 7.0 percent range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

Q. What cost of common equity estimates are implied by your DCF results for the Gas Group?

A. As shown on page 3 of Exhibit No. 301, Schedule AMM-3 and summarized in Table No. 6, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

Table No. 6:

DCF RESULTS – GAS GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.3%	10.7%
IBES	9.5%	10.3%
Zacks	8.6%	8.9%
br + sv	9.5%	10.3%

Q. What were the results of your DCF analysis for the Combination Group?

A. I applied the DCF model to the Combination Group in exactly the same manner described earlier for the Gas Group. The results of my DCF analysis for the Combination Group are presented in Exhibit No. 301, Schedule AMM-5, with the sustainable, "br+sv" growth rates being developed on Exhibit No. 301, Schedule AMM-6.

As shown on page 3 of Exhibit No. 301, Schedule AMM-5 and summarized in Table No. 7, below, after eliminating illogical values, application of the constant growth DCF model to the Combination Group resulted in the following cost of equity estimates:

Table No. 7:

DCF RESULTS – COMBINATION GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.0%	10.1%
IBES	9.1%	9.2%
Zacks	9.0%	9.2%
br + sv	8.5%	9.2%

C. Empirical Capital Asset Pricing Model

Q. Please describe the ECAPM.

A. The ECAPM is a variant of the traditional CAPM, which is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. As previously stated, a stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the ECAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the ECAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. Why is the ECAPM approach an appropriate component in evaluating the cost of equity for the Company?

A. The CAPM approach, which forms the foundation of the ECAPM, generally is considered to be the most widely referenced method among academicians and professional practitioners for estimating the cost of equity, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is a dominant model for estimating the cost of equity outside the regulatory sphere, the ECAPM provides important insight into investors' required rate of return for utility stocks, including Avista.

Q. How does the ECAPM approach differ from traditional applications of the CAPM?

A. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[28]

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$Rj = Rf + 0.25(Rm - Rf) + 0.75[\beta j(Rm - Rf)]$$

This ECAPM equation, and the associated weighting factors, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and correct for the understated returns that would otherwise be produced for low beta stocks.

Q. How did you apply the ECAPM to estimate the cost of common equity?

A. Application of the ECAPM to the Gas Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. 301, Schedule AMM-7. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its

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[28] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

proportionate share of total market value. Based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 9.2 percent. Combining this average growth rate with a year-ahead dividend yield of 2.3 percent results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 11.5 percent. Subtracting a 2.9 percent risk-free rate based on the average yield on 30-year Treasury bonds for February 2015 produced a market equity risk premium of 8.6 percent

Q. What was the source of the beta values you used to apply the ECAPM?

A. As indicated earlier, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

Q. What else should be considered in applying the ECAPM?

A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[29]

Because financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the ECAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to

[29] *Morningstar*, "Ibbotson SBBI 2014 Valuation Yearbook," at p. 85.

firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical ECAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the ECAPM cost of equity. These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of approximately 5.7 percent for a company in the first decile (market capitalization less than $300.8 million), to a reduction of 32 basis points for firms in the tenth decile (market capitalization greater than between $24.4 billion).[30] Accordingly, my ECAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Gas Group.

Q. What is the implied ROE for the Gas Group using the ECAPM approach?

A. As shown on page 1 of Exhibit No. 301, Schedule AMM-7, a forward-looking application of the ECAPM approach resulted in an average unadjusted ROE estimate of 10.1 percent.[31] After adjusting for the impact of firm size, the ECAPM approach implied an average cost of equity of 11.6 percent for the Gas Group, with a midpoint cost of equity estimate of 11.7 percent.

Q. Did you also apply the ECAPM using forecasted bond yields?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen and the Federal Reserve normalizes its monetary policy. Accordingly, in addition to the use of historical bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. As shown

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[30] *Morningstar*, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).
[31] The midpoint of the unadjusted ECAPM range was 10.0 percent.

on page 2 of Exhibit No. 301, Schedule AMM-7, incorporating a forecasted Treasury bond yield for 2015-2019 implied a cost of equity of 10.4 percent for the Gas Group, or 11.8 percent after adjusting for the impact of relative size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 10.3 percent and 11.8 percent, respectively.

Q. What implied ROEs were indicated for the Combination Group using the ECAPM approach?

A. An identical application of the ECAPM to the firms in the Combination Group is presented on Exhibit No. 301, Schedule AMM-8. As shown on page 1, the forward-looking ECAPM analysis resulted in an average unadjusted ROE estimate of 9.8 percent for the Combination group, or 10.6 percent after adjusting for the impact of firm size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 9.9 percent and 10.6 percent, respectively. Incorporating a projected Treasury bond yield for 2015-2019 (Exhibit No. 301, Schedule AMM-8, p. 2) implied a cost of equity of approximately 10.0 percent for the Combination Group, or 10.9 percent after adjusting for the impact of relative size.[32]

D. <u>Utility Risk Premium</u>

Q. Briefly describe the risk premium method.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk

[32] The midpoint of the unadjusted ECAPM range was 10.2 percent, or 10.8 percent after adjusting for relative size.

premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for Avista.

Q. How did you implement the risk premium method?

A. Estimates of equity risk premiums for utilities were based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. Is it circular to consider risk premiums based on authorized returns in assessing a fair ROE for Avista?

A. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (*e.g.*, stock prices, dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q. How did you calculate the equity risk premiums based on allowed ROEs?

A. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit No. 301, Schedule AMM-9, the average yield on single-A public utility bonds is subtracted from the average allowed ROE for gas utilities to calculate equity risk premiums for each quarter between 1980 and 2014. As shown on page 3 of Exhibit No. 301, Schedule AMM-9, over this period, these equity risk premiums for gas utilities averaged 3.34 percent, and the yield on single-A public utility bonds averaged 8.50 percent.

Q. Is there any capital market relationship that must be considered when implementing the risk premium method?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[33] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The

[33] *See, e.g.*, Brigham, E.F., Shome, D.K., and Vinson, S.R., “The Risk Premium Approach to Measuring a Utility’s Cost of Equity,” *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., “Estimating Shareholder Risk Premia Using Analysts’ Growth Forecasts,” *Financial Management* (Summer 1992).

implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1 percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Q. Has this inverse relationship been documented in the financial research?

A. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater.[34] This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, *New Regulatory Finance* documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[35]

Other regulators have also recognized that the cost of equity does not move in tandem with interest rates.[36]

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[34] *Id.*
[35] Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, at 128 (2006).
[36] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf; *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

Q. What are the implications of this relationship under current capital market conditions?

A. As noted earlier, bond yields are at unprecedented lows. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q. What cost of equity is implied by the risk premium method using surveys of allowed ROEs?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit No. 301, Schedule AMM-9, the equity risk premium for gas utilities increased approximately 46 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. 301, Schedule AMM-9, with an average yield on single-A public utility bonds for the six-months ending February 2015 of 3.93 percent, this implied a current equity risk premium of 5.45 percent for gas utilities. Adding this equity risk premium to the average yield on triple-B utility bonds for the six-months ended February 2015 of 4.62 percent implies a current cost of equity of approximately 10.07 percent.

Q. What risk premium cost of equity estimates were produced for Avista's gas utility operations after incorporating forecasted bond yields?

A. As shown on page 2 of Exhibit No. 301, Schedule AMM-9, incorporating a forecasted yield for 2015-2019 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.43 percent for gas utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2015-2019 of 6.84 percent resulted in an implied cost of equity of approximately 11.27 percent.

E. <u>Flotation Costs</u>

Q. What other considerations are relevant in setting the return on equity for a utility?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q. Is there a theoretical and practical basis to include a flotation cost adjustment in this case?

A. Yes. First, an adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[37] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to

[37] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985.

> most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[38]

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. There are a number of ways in which a flotation cost adjustment can be calculated, but the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[39]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6 percent.[40]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to an average dividend yield of 3.2 percent implies a flotation cost adjustment on the order of 10 basis points.

Q. Did you include a flotation cost adjustment in arriving at your recommended ROE range?

A. Yes. I included a minimum adjustment for flotation costs of 10 basis points in evaluating a fair ROE range for Avista.

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[38] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 335 (2006).
[39] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).
[40] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6 percent.

VI. OTHER ROE BENCHMARKS

Q. What is the purpose of this section of your testimony?

A. This section presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances of Avista. The first test is based on applications of the traditional CAPM analysis using current and projected interest rates. The second test is based on expected earned returns for gas utilities. Finally, I present a DCF analysis for a select, low risk group of non-utility firms, with which Avista must compete for investors' money.

A. Capital Asset Pricing Model

Q. What cost of equity estimates were indicated by the traditional CAPM?

A. My applications of the traditional CAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the ECAPM. As shown on page 1 of Exhibit No. 301, Schedule AMM-10, applying the forward-looking CAPM approach to the firms in the Gas Group results in an average theoretical cost of equity estimate of 9.7 percent, or 11.1 percent after incorporating the size adjustment corresponding to the market capitalization of the individual utilities. As shown on page 1 of Exhibit No. 301, Schedule AMM-11, adjusting the 9.2 percent theoretical CAPM result for the Combination Group to incorporate the size adjustment results in an average indicated cost of common equity of 10.0 percent.

As shown on page 2 of Exhibit No. 301, Schedule AMM-10, incorporating a forecasted Treasury bond yield for 2015-2019 implied a cost of equity of approximately 10.0 percent for the Gas Group, or 11.4 percent after adjusting for the impact of relative size. For the Combination Group (page 2 of Exhibit No. 301, Schedule AMM-11), projected bond yields implied a theoretical CAPM estimate of 9.6 percent, or 10.4 percent after incorporating the size adjustment.

B. <u>Expected Earnings Approach</u>

Q. What other analyses did you conduct to estimate the cost of common equity?

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What economic premise underlies the expected earnings approach?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation regulation is effectively taking the value of investors' capital without adequate compensation, contrary to *Hope* and *Bluefield*. The expected earnings approach is consistent with the economic rationale underpinning established regulatory standards, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other regional utilities.

Q. How is the expected earnings approach typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices – both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. As FERC recently concluded:

> The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity, because those

> returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk.[41]

This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. What rates of return on equity are indicated for utilities based on the expected earnings approach?

A. Value Line's projected year-end returns on common equity for the firms in the Gas Group are shown on page 1 of Exhibit No. 301, Schedule AMM-12. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit No. 301, Schedule AMM-4. As shown on page 1 of Exhibit No. 301, Schedule AMM-12, Value Line's projections for the Gas Group suggest an average ROE of approximately 11.3 percent. As shown on page 2 of Exhibit No. 301, Schedule AMM-12, Value Line's projections for the Combination Group suggested an average ROE of 10.7 percent.[42]

[41] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015).
[42] The midpoint values for the Gas and Electric Groups were 11.9 percent and 11.7 percent, respectively.

C. <u>Low Risk Non-Utility DCF</u>

Q. What other proxy group did you consider in evaluating a fair ROE for Avista?

A. Consistent with underlying economic and regulatory standards, I also applied the DCF model to a reference group of low-risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Group".

Q. Do utilities have to compete with non-regulated firms for capital?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q. Is it consistent with the Bluefield and Hope cases to consider investors' required ROE for non-utility companies?

A. Yes. The cost of equity capital in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[43]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q. Does consideration of the results for the Non-Utility Group make the estimation of the cost of equity using the DCF model more reliable?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q. What criteria did you apply to develop the Non-Utility Group?

A. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;
2) have a Safety Rank of "1";
3) have a Financial Strength Rating of "B++" or greater;
4) have a beta of 0.70 or less; and
5) have investment grade credit ratings from S&P.

[43] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

Q. How do the overall risks of this Non-Utility Group compare with the Gas and Combination Groups?

A. Table No. 8 compares the Non-Utility Group with the Gas and Combination Groups across the measures of investment risk discussed earlier:

Table No. 8

COMPARISON OF RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A	A2	1	A++	0.66
Gas Utility	A-	A3	2	A	0.79
Combination Utility	BBB+	Baa1	2	B++	0.73
Avista	**BBB**	**Baa1**	**2**	**A**	**0.8**

As shown above, the average credit rating, Safety Rank, Financial Strength Rating, and beta for the Non-Utility Group suggest less risk than for Avista and the proxy groups of utilities. When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the Gas and Combination Groups are greater than those of the firms in the Non-Utility Group.

The thirteen companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Colgate-Palmolive, McDonalds, and Wal-Mart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3 percent. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q. What were the results of your DCF analysis for the Non-Utility Group?

A. I applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Gas and Combination Groups, The results of my DCF analysis for the Non-Utility Group are presented in Exhibit No. 301, Schedule AMM-13. As summarized in Table No. 9, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

Table No. 9

DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.3%	10.4%
IBES	9.6%	9.7%
Zacks	10.2%	10.2%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Considering that the investment risks of the Non-Utility Group are lower than those of the proxy groups of utilities and Avista, these results understate investors' required rate of return for the Company.

Q. Please summarize the results of your alternative ROE benchmarks.

A. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit No. 301, Schedule AMM-1, and summarized in Table No. 10, below:

Table No. 10:

SUMMARY OF ALTERNATIVE ROE BENCHMARKS

	Gas Group		Combination Group	
	Average	Midpoint	Average	Midpoint
CAPM - Current Bond Yield				
Unadjusted	9.7%	9.6%	9.2%	9.4%
Size Adjusted	11.1%	11.2%	10.0%	10.0%
CAPM - Projected Bond Yield				
Unadjusted	10.0%	9.9%	9.6%	9.7%
Size Adjusted	11.4%	11.5%	10.4%	10.4%
Expected Earnings - Gas Group	11.3%	11.9%	10.3%	10.5%
Non-Utility DCF				
Value Line	10.3%	10.4%		
IBES	9.6%	9.7%		
Zacks	10.2%	10.2%		

The results of these checks of reasonableness confirm my conclusion that an ROE of 9.9 percent for Avista's gas utility operations is conservative.

VII. IMPACT OF REGULATORY MECHANISMS

Q. Would any adjustment to the ROE be warranted due to Avista's proposed revenue decoupling mechanism?

A. No. Investors recognize that Avista is exposed to significant risks associated with the ability to recover rising costs and investment on a timely basis, and concerns over these risks have become increasingly pronounced in the industry. The revenue decoupling mechanism proposed by the Company is a valuable means of reducing some of those risks, but it does not eliminate them. While approval of Avista's proposed decoupling mechanism would attenuate exposure certain variations in revenue between general rate cases, this leveling of the playing field only serves to address factors that could otherwise impair the Company's opportunity to earn its authorized return, as required by established regulatory standards.

Q. Is there any evidence to suggest that approval of revenue decoupling should result is a downward adjustment to Avista's allowed ROE?

A. No. As noted earlier, the investment community and the major credit rating agencies in particular, pay close attention to the regulatory framework, including cost adjustment mechanisms. Based largely on the expanded use of ratemaking mechanisms such as revenue decoupling and cost-recovery riders, Moody's upgraded most regulated utilities in January 2014.[44] Recognizing this industry trend, Moody's premised its assessment of Avista's risks on the expectation that "similar treatment will be afforded to Avista and that the company will have improved cost recovery mechanisms (e.g., decoupling)."[45] In other words, the implications of revenue decoupling and other regulatory mechanisms are <u>already fully reflected</u> in Avista's credit ratings, which are comparable to those of the proxy group used to estimate the cost of equity.

Q. Would approval of the Company's proposed revenue decoupling mechanisms set Avista apart from other firms operating in the utility industry?

A. No. Adjustment mechanisms and cost trackers have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity

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[44] Moody's Investors Service, "US utility sector upgrades driven by stable and transparent regulatory frameworks," *Sector Comment* (Feb. 3, 2014).
[45] Moody's Investors Service, "Avista Corp.," *Global Credit Research* (Mar. 28, 2014).

of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of adjustment mechanisms.

Reflective of this trend, the companies in the gas and electric utility industries operate under a wide variety of cost adjustment mechanisms, which range from riders to recover bad debt expense and post-retirement employee benefit costs to revenue decoupling and adjustment clauses designed to address rising capital investment outside of a traditional rate case and increasing costs of environmental compliance measures. The majority of gas utilities benefit from revenue decoupling, along with a variety of other provisions that enhance their ability to recover operating and capital costs on a timely basis.[46] Similarly, Regulatory Research Associates concluded in its recent review of adjustment clauses that, "some form of decoupling is in place in the vast majority of jurisdictions."[47] The firms in the Non-Utility Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. As a result, the mitigation in risks associated with utilities' ability to adjust revenues and attenuate the risk of cost recovery is already reflected in the cost of equity range determined earlier, and no separate adjustment to Avista's ROE is necessary or warranted.

Q. Have you summarized the various tracking mechanisms available to the other firms in the Gas and Combination Groups?

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[46] *See, e.g.,* American Gas Association, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List* (Jan. 2015).

[47] Regulatory Research Associates, "Adjustment Clauses, A State-by-State Overview," *Regulatory Focus* (Jul. 1, 2014).

A. Yes. Reflective of industry trends, the companies in the Gas and Combination Groups operate under a variety of regulatory adjustment mechanisms.[48] As summarized on Schedule 14, these mechanisms are ubiquitous and wide ranging. For example, nine of the ten firms in the Gas Group have utilities that operate under some form of decoupling mechanism that accounts for the impact of various factors affecting sales volumes and revenues. In addition, Atmos Energy Corporation has utilities that operate under enhanced rate design provisions, which have a similar impact. Similarly, fourteen of the utilities in the Combination Group benefit from some form of revenue decoupling or operate in jurisdictions that allow the use of future test years. Many of these utilities operate under mechanisms that allow for cost recovery of infrastructure investment outside a formal rate proceeding, as well as the ability to implement periodic rate adjustments to reflect changes in a diverse range of operating and capital costs, including expenditures related to environmental mandates, conservation programs, transmission costs, and storm recovery efforts.

Q. Have other regulators recognized that approval of adjustment mechanisms do not warrant an adjustment to the ROE?

A. Yes. For example, the Staff of the Kansas State Corporation Commission concluded that no ROE adjustment was justified in the case of certain tariff riders because the impact of similar mechanisms is already accounted for through the use of a proxy group:

> Those mechanisms differ from company to company and jurisdiction to jurisdiction. Regardless of their nuances, the intent is the same; reduce cash-flow volatility year to year and place recent capital expenditures in rates as quickly as possible. Investors are aware of these mechanisms and their benefits are a factor when investors value those stocks. Thus, any risk

[48] Because this information is widely referenced by the investment community, it is also directly relevant to an evaluation of the risks and prospects that determine the cost of equity.

> reduction associated with these mechanisms is captured in the market data (stock prices) used in Staff's analysis.[49]

Similarly, any mitigation in risks associated with decoupling is already reflected in the results of the quantitative methods presented in my testimony.

Q. What does this imply with respect to the evaluation of a fair ROE for Avista?

A. While investors would consider approval of Avista's proposed decoupling mechanism to be supportive of the Company's financial integrity and credit ratings, there is certainly no evidence to suggest that this mechanism alone would alter Avista's relative risk enough to warrant an ROE adjustment. The purpose of regulatory mechanisms is to better match revenues to the underlying costs of providing service. This levels the playing field and improves Avista's ability to attract capital and actually earn its authorized ROE, but it does not result in a "windfall" or otherwise penalize customers. Utilities across the U.S. that Avista competes with for new capital are increasingly availing themselves of similar adjustments. As a result, the effect of decoupling on ROE is already reflected in the cost of equity estimates determined in this case, and no separate adjustment to Avista's ROE is necessary or warranted.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

[49] *Direct Testimony Prepared by Adam H. Gatewood*, State Corporation Commission of the State of Kansas, Docket No. 12-ATMG-564-RTS, pp. 8-9 (June 8, 2012). This proceeding was ultimately resolved through a stipulated settlement.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

ADRIEN M. MCKENZIE
Exhibit No. 301

Return on Equity

SUMMARY OF RESULTS

	Gas Group		Combination Group	
DCF	**Average**	**Midpoint**	**Average**	**Midpoint**
Value Line	10.3%	10.7%	10.0%	10.1%
IBES	9.5%	10.3%	9.1%	9.2%
Zacks	8.6%	8.9%	9.0%	9.2%
Internal br + sv	9.5%	10.3%	8.5%	9.2%
Empirical CAPM - Current Bond Yield				
Unadjusted	10.1%	10.0%	9.8%	9.9%
Size Adjusted	11.6%	11.7%	10.6%	10.6%
Empirical CAPM - Projected Bond Yield				
Unadjusted	10.4%	10.3%	10.0%	10.2%
Size Adjusted	11.8%	11.8%	10.9%	10.8%
Utility Risk Premium				
Current Bond Yields	10.1%		--	
Projected Bond Yields	11.3%		--	

	Cost of Equity Recommendation		
Cost of Equity Range	**9.5%**	**--**	**10.8%**
Flotation Cost Adjustment			
Dividend Yield	3.2%		3.2%
Flotation Cost Percentage	3.6%		3.6%
Adjustment	0.1%		0.1%
Recommended ROE Range	**9.6%**	**--**	**10.9%**

CHECKS OF REASONABLENESS

	Gas Group		Combination Group	
	Average	Midpoint	Average	Midpoint
CAPM - Current Bond Yield				
Unadjusted	9.7%	9.6%	9.2%	9.4%
Size Adjusted	11.1%	11.2%	10.0%	10.0%
CAPM - Projected Bond Yield				
Unadjusted	10.0%	9.9%	9.6%	9.7%
Size Adjusted	11.4%	11.5%	10.4%	10.4%
Expected Earnings - Gas Group	11.3%	11.9%	10.7%	11.7%
Non-Utility DCF				
Value Line	10.3%	10.4%		
IBES	9.6%	9.7%		
Zacks	10.2%	10.2%		

GAS GROUP

		At Fiscal Year-End 2014 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	AGL Resources	49.8%	0.0%	50.2%	44.5%	0.0%	55.5%
2	Atmos Energy Corp.	44.3%	0.0%	55.7%	45.0%	0.0%	55.0%
3	Laclede Group	55.1%	0.0%	44.9%	51.0%	0.0%	49.0%
4	New Jersey Resources	39.6%	0.0%	60.4%	27.5%	0.0%	72.5%
5	NiSource, Inc.	57.7%	0.0%	42.3%	56.0%	0.0%	44.0%
6	Northwest Natural Gas	46.3%	0.0%	53.7%	45.5%	1.0%	53.5%
7	Piedmont Natural Gas	52.1%	0.0%	47.9%	43.0%	0.5%	56.5%
8	South Jersey Industries	52.0%	0.0%	48.0%	49.0%	0.0%	51.0%
9	Southwest Gas Corp.	52.7%	0.0%	47.3%	49.5%	0.0%	50.5%
10	WGL Holdings, Inc.	35.4%	1.4%	63.2%	27.0%	1.5%	71.5%
	Average	**48.5%**	**0.1%**	**51.4%**	**43.8%**	**0.3%**	**55.9%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Mar. 6, 2015).

COMBINATION GROUP

		At Fiscal Year-End 2014 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	Alliant Energy	51.0%	2.7%	46.3%	47.5%	3.0%	49.5%
2	Ameren Corp.	47.7%	1.1%	51.3%	45.0%	1.0%	54.0%
3	Avista Corp.	50.3%	0.0%	49.7%	51.0%	0.0%	49.0%
4	Black Hills Corp.	52.9%	0.0%	47.1%	53.5%	0.0%	46.5%
5	CenterPoint Energy	55.2%	0.0%	44.8%	58.0%	0.0%	42.0%
6	CMS Energy Corp.	69.8%	0.0%	30.2%	65.5%	0.0%	34.5%
7	Consolidated Edison	49.2%	0.0%	50.8%	48.0%	0.0%	52.0%
8	Dominion Resources	62.3%	0.0%	37.7%	58.0%	0.0%	42.0%
9	DTE Energy Co.	50.8%	0.0%	49.2%	51.0%	0.0%	49.0%
10	Duke Energy Corp.	49.5%	0.0%	50.5%	53.0%	0.0%	47.0%
11	Empire District Elec	50.6%	0.0%	49.4%	50.0%	0.0%	50.0%
12	Entergy Corp.	57.0%	0.4%	42.6%	52.5%	1.0%	46.5%
13	Eversource Energy	46.6%	0.0%	53.4%	45.5%	0.5%	54.0%
14	MGE Energy	37.7%	0.0%	62.3%	35.0%	0.0%	65.0%
15	NorthWestern Corp.	53.0%	0.0%	47.0%	45.5%	0.0%	54.5%
16	PG&E Corp.	48.5%	0.8%	50.7%	49.5%	0.5%	50.0%
17	Pub Sv Enterprise Grp	42.2%	0.0%	57.8%	45.5%	0.0%	54.5%
18	SCANA Corp.	53.3%	0.0%	46.7%	54.0%	0.0%	46.0%
19	Sempra Energy	51.1%	0.1%	48.8%	51.5%	0.0%	48.5%
20	Vectren Corp.	49.5%	0.0%	50.5%	48.0%	0.0%	52.0%
21	Xcel Energy Inc.	53.5%	0.0%	46.5%	52.5%	0.0%	47.5%
	Average	**51.5%**	**0.2%**	**48.3%**	**50.5%**	**0.3%**	**49.2%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).

DIVIDEND YIELD

		(a)	(b)	
	Company	**Price**	**Dividends**	**Yield**
1	AGL Resources	$ 52.48	$ 2.04	3.9%
2	Atmos Energy Corp.	$ 54.79	$ 1.60	2.9%
3	Laclede Group	$ 52.88	$ 1.84	3.5%
4	New Jersey Resources	$ 31.91	$ 0.92	2.9%
5	NiSource, Inc.	$ 43.41	$ 1.04	2.4%
6	Northwest Natural Gas	$ 48.61	$ 1.86	3.8%
7	Piedmont Natural Gas	$ 38.44	$ 1.28	3.3%
8	South Jersey Industries	$ 57.55	$ 2.05	3.6%
9	Southwest Gas Corp.	$ 59.07	$ 1.62	2.7%
10	WGL Holdings, Inc.	$ 54.78	$ 1.85	3.4%
	Average			**3.2%**

(a) Average of closing prices for 30 trading days ended Mar. 6, 2015 from yahoo.com.
(b) The Value Line Investment Survey, *Summary & Index* (Mar. 6, 2015).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	AGL Resources	6.5%	NA	4.7%	6.3%
2	Atmos Energy Corp.	7.0%	7.0%	7.0%	7.9%
3	Laclede Group	10.0%	4.7%	4.9%	4.6%
4	New Jersey Resources	2.0%	4.0%	4.0%	5.9%
5	NiSource, Inc.	9.0%	10.4%	5.5%	6.0%
6	Northwest Natural Gas	5.5%	4.0%	4.0%	3.8%
7	Piedmont Natural Gas	3.0%	5.0%	5.0%	3.6%
8	South Jersey Industries	7.5%	6.0%	6.0%	9.5%
9	Southwest Gas Corp.	6.0%	4.0%	5.5%	7.9%
10	WGL Holdings, Inc.	4.5%	6.5%	5.3%	4.6%

(a) The Value Line Investment Survey (Mar. 6, 2015).
(b) www.finance.yahoo.com (retrieved Mar. 20, 2015).
(c) www.zacks.com (retrieved Mar. 20, 2015).
(d) See Avista/301, Schedule AMM-4.

DCF COST OF EQUITY ESTIMATES

	Company	(a) Earnings Growth V Line	(a) Earnings Growth IBES	(a) Earnings Growth Zacks	(a) br+sv Growth
1	AGL Resources	10.4%	NA	8.6%	10.2%
2	Atmos Energy Corp.	9.9%	9.9%	9.9%	10.9%
3	Laclede Group	13.5%	8.2%	8.4%	8.1%
4	New Jersey Resources	4.9%	6.9%	6.9%	8.8%
5	NiSource, Inc.	11.4%	12.8%	7.9%	8.4%
6	Northwest Natural Gas	9.3%	7.8%	7.8%	7.6%
7	Piedmont Natural Gas	6.3%	8.3%	8.3%	6.9%
8	South Jersey Industries	11.1%	9.6%	9.6%	13.0%
9	Southwest Gas Corp.	8.7%	6.7%	8.2%	10.6%
10	WGL Holdings, Inc.	7.9%	9.9%	8.6%	8.0%
	Average (b)	**10.3%**	**9.5%**	**8.6%**	**9.5%**
	Midpoint (c)	**10.7%**	**10.3%**	**8.9%**	**10.3%**

(a) Sum of dividend yield (Avista/301, Schedule AMM-3, p. 1) and respective growth rate (Avista/301,

(b) Excludes highlighted figures.

(c) Average of low and high values.

DCF MODEL - GAS GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		------------- 2019 -------------					Adjustment			--------- "sv" Factor --------			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	AGL Resources	$4.65	$2.40	$40.70	48.4%	11.4%	1.0297	11.8%	5.7%	0.0151	0.4186	0.63%	**6.3%**
2	Atmos Energy Corp.	$3.80	$1.90	$36.65	50.0%	10.4%	1.0354	10.7%	5.4%	0.0620	0.4136	2.56%	**7.9%**
3	Laclede Group	$4.20	$2.20	$48.10	47.6%	8.7%	1.0357	9.0%	4.3%	0.0112	0.2600	0.29%	**4.6%**
4	New Jersey Resources	$1.85	$0.98	$15.65	47.0%	11.8%	1.0316	12.2%	5.7%	0.0033	0.4309	0.14%	**5.9%**
5	NiSource, Inc.	$2.60	$1.20	$25.55	53.8%	10.2%	1.0293	10.5%	5.6%	0.0093	0.3988	0.37%	**6.0%**
6	Northwest Natural Gas	$3.30	$2.10	$36.15	36.4%	9.1%	1.0242	9.3%	3.4%	0.0111	0.3427	0.38%	**3.8%**
7	Piedmont Natural Gas	$2.10	$1.47	$20.40	30.0%	10.3%	1.0219	10.5%	3.2%	0.0099	0.4560	0.45%	**3.6%**
8	South Jersey Industries	$5.00	$2.65	$34.20	47.0%	14.6%	1.0371	15.2%	7.1%	0.0460	0.5114	2.35%	**9.5%**
9	Southwest Gas Corp.	$4.25	$2.10	$35.60	50.6%	11.9%	1.0215	12.2%	6.2%	0.0395	0.4304	1.70%	**7.9%**
10	WGL Holdings, Inc.	$3.20	$1.87	$30.00	41.6%	10.7%	1.0228	10.9%	4.5%	0.0015	0.4000	0.06%	**4.6%**

DCF MODEL - GAS GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2014			2019			Chg	2019 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2014	2019	Growth
1	AGL Resources	51.2%	$7,386	$3,782	55.5%	$9,175	$5,092	6.1%	$75.00	$65.00	$70.00	1.720	119.65	125.00	0.88%
2	Atmos Energy Corp.	55.7%	$5,542	$3,087	55.0%	$8,000	$4,400	7.3%	$70.00	$55.00	$62.50	1.705	100.39	120.00	3.63%
3	Laclede Group	44.9%	$3,359	$1,508	49.0%	$4,400	$2,156	7.4%	$75.00	$55.00	$65.00	1.351	43.18	45.00	0.83%
4	New Jersey Resources	61.8%	$1,564	$967	72.5%	$1,830	$1,327	6.5%	$30.00	$25.00	$27.50	1.757	84.20	85.00	0.19%
5	NiSource, Inc.	43.1%	$14,331	$6,177	44.0%	$18,810	$8,276	6.0%	$50.00	$35.00	$42.50	1.663	316.04	325.00	0.56%
6	Northwest Natural Gas	52.5%	$1,480	$777	53.5%	$1,850	$990	5.0%	$60.00	$50.00	$55.00	1.521	27.00	28.00	0.73%
7	Piedmont Natural Gas	47.9%	$2,733	$1,309	56.5%	$2,885	$1,630	4.5%	$45.00	$30.00	$37.50	1.838	77.88	80.00	0.54%
8	South Jersey Industries	48.5%	$1,850	$897	51.0%	$2,550	$1,301	7.7%	$80.00	$60.00	$70.00	2.047	34.00	38.00	2.25%
9	Southwest Gas Corp.	47.3%	$3,144	$1,487	50.5%	$3,650	$1,843	4.4%	$75.00	$50.00	$62.50	1.756	46.52	52.00	2.25%
10	WGL Holdings, Inc.	63.8%	$1,954	$1,247	71.5%	$2,190	$1,566	4.7%	$55.00	$45.00	$50.00	1.667	51.76	52.00	0.09%

(a) The Value Line Investment Survey (Mar. 6, 2015).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2019 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2019 BVPS.

DIVIDEND YIELD

		(a)	(b)	
	Company	**Price**	**Dividends**	**Yield**
1	Alliant Energy	$ 63.16	$ 2.20	3.5%
2	Ameren Corp.	$ 42.20	$ 1.66	3.9%
3	Avista Corp.	$ 33.77	$ 1.32	3.9%
4	Black Hills Corp.	$ 49.75	$ 1.62	3.3%
5	CenterPoint Energy	$ 21.28	$ 1.00	4.7%
6	CMS Energy Corp.	$ 34.83	$ 1.18	3.4%
7	Consolidated Edison	$ 63.02	$ 2.62	4.2%
8	Dominion Resources	$ 72.11	$ 2.59	3.6%
9	DTE Energy Co.	$ 81.56	$ 2.87	3.5%
10	Duke Energy Corp.	$ 78.13	$ 3.23	4.1%
11	Empire District Elec	$ 25.14	$ 1.05	4.2%
12	Entergy Corp.	$ 78.32	$ 3.32	4.2%
13	Eversource Energy	$ 51.23	$ 1.67	3.3%
14	MGE Energy	$ 43.08	$ 1.16	2.7%
15	NorthWestern Corp.	$ 53.59	$ 1.92	3.6%
16	PG&E Corp.	$ 54.00	$ 1.82	3.4%
17	Pub Sv Enterprise Grp	$ 41.03	$ 1.56	3.8%
18	SCANA Corp.	$ 56.56	$ 2.18	3.9%
19	Sempra Energy	$108.50	$ 2.80	2.6%
20	Vectren Corp.	$ 44.39	$ 1.56	3.5%
21	Xcel Energy Inc.	$ 35.04	$ 1.28	3.7%
	Average			**3.7%**

(a) Average of closing prices for 30 trading days ended Mar. 20, 2015.

(b) The Value Line Investment Survey, Summary & Index (Mar. 20, 2015).

GROWTH RATES

		(a)	(b)	(c)	(e)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	Alliant Energy	6.0%	5.4%	5.3%	4.7%
2	Ameren Corp.	5.0%	6.9%	7.4%	4.3%
3	Avista Corp.	5.5%	5.0%	NA	3.1%
4	Black Hills Corp.	9.5%	7.0%	NA	4.2%
5	CenterPoint Energy	1.5%	1.6%	5.0%	3.5%
6	CMS Energy Corp.	5.5%	6.7%	6.2%	5.0%
7	Consolidated Edison	2.5%	2.8%	3.0%	3.2%
8	Dominion Resources	7.5%	5.8%	6.0%	7.5%
9	DTE Energy Co.	6.0%	4.5%	5.1%	4.4%
10	Duke Energy Corp.	5.0%	4.5%	4.7%	3.0%
11	Empire District Elec	3.0%	3.0%	3.0%	3.2%
12	Entergy Corp.	-0.5%	-1.2%	3.0%	3.4%
13	Eversource Energy	8.0%	6.3%	6.4%	4.6%
14	MGE Energy	7.5%	4.0%	NA	8.8%
15	NorthWestern Corp.	6.5%	7.6%	7.6%	5.2%
16	PG&E Corp.	8.0%	4.0%	4.6%	4.1%
17	Pub Sv Enterprise Grp	3.0%	2.2%	2.5%	5.2%
18	SCANA Corp.	6.0%	4.3%	4.2%	5.5%
19	Sempra Energy	6.0%	7.6%	7.9%	5.9%
20	Vectren Corp.	9.5%	5.5%	5.7%	8.0%
21	Xcel Energy Inc.	5.5%	4.5%	4.7%	4.6%

(a) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).

(b) www.finance.yahoo.com (retrieved Mar. 16, 2015).

(c) www.zacks.com (retrieved Mar. 16, 2015).

(d) See Avista/301, Schedule AMM-6.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	Alliant Energy	9.5%	8.9%	8.8%	8.2%
2	Ameren Corp.	8.9%	10.8%	11.3%	8.3%
3	Avista Corp.	9.4%	8.9%	NA	7.0%
4	Black Hills Corp.	12.8%	10.3%	NA	7.5%
5	CenterPoint Energy	6.2%	6.3%	9.7%	8.2%
6	CMS Energy Corp.	8.9%	10.1%	9.6%	8.4%
7	Consolidated Edison	6.7%	6.9%	7.2%	7.3%
8	Dominion Resources	11.1%	9.4%	9.6%	11.0%
9	DTE Energy Co.	9.5%	8.0%	8.6%	8.0%
10	Duke Energy Corp.	9.1%	8.7%	8.8%	7.2%
11	Empire District Elec	7.2%	7.2%	7.2%	7.4%
12	Entergy Corp.	3.7%	3.1%	7.2%	7.6%
13	Eversource Energy	11.3%	9.5%	9.7%	7.8%
14	MGE Energy	10.2%	6.7%	NA	11.5%
15	NorthWestern Corp.	10.1%	11.2%	11.2%	8.8%
16	PG&E Corp.	11.4%	7.3%	8.0%	7.4%
17	Pub Sv Enterprise Grp	6.8%	6.0%	6.3%	9.0%
18	SCANA Corp.	9.9%	8.2%	8.1%	9.3%
19	Sempra Energy	8.6%	10.2%	10.4%	8.5%
20	Vectren Corp.	13.0%	9.0%	9.2%	11.5%
21	Xcel Energy Inc.	9.2%	8.2%	8.4%	8.3%
	Average (b)	**10.0%**	**9.1%**	**9.0%**	**8.5%**
	Midpoint (c)	**10.1%**	**9.2%**	**9.2%**	**9.2%**

(a) Sum of dividend yield (Avista/301, Schedule AMM-5, p. 1) and respective growth rate
(b) Excludes highlighted figures.
(c) Average of low and high values.

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		------------	2018/19	------------			Adjustment			---------	"sv" Factor	--------	
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$4.25	$2.85	$34.65	32.9%	12.3%	1.0113	12.4%	4.1%	0.0135	0.4669	0.63%	**4.7%**
2	Ameren Corp.	$3.25	$1.85	$34.00	43.1%	9.6%	1.0238	9.8%	4.2%	0.0070	0.1500	0.11%	**4.3%**
3	Avista Corp.	$2.25	$1.50	$26.75	33.3%	8.4%	1.0286	8.7%	2.9%	0.0160	0.1083	0.17%	**3.1%**
4	Black Hills Corp.	$3.25	$1.85	$35.75	43.1%	9.1%	1.0218	9.3%	4.0%	0.0078	0.2850	0.22%	**4.2%**
5	CenterPoint Energy	$1.45	$1.15	$12.00	20.7%	12.1%	1.0182	12.3%	2.5%	0.0190	0.5200	0.99%	**3.5%**
6	CMS Energy Corp.	$2.25	$1.50	$17.75	33.3%	12.7%	1.0329	13.1%	4.4%	0.0138	0.4929	0.68%	**5.0%**
7	Consolidated Edison	$4.50	$2.90	$51.00	35.6%	8.8%	1.0170	9.0%	3.2%	-	0.1840	0.00%	**3.2%**
8	Dominion Resources	$4.75	$3.50	$28.50	26.3%	16.7%	1.0403	17.3%	4.6%	0.0442	0.6545	2.90%	**7.5%**
9	DTE Energy Co.	$5.75	$3.50	$59.00	39.1%	9.7%	1.0310	10.0%	3.9%	0.0215	0.2387	0.51%	**4.4%**
10	Duke Energy Corp.	$5.50	$3.55	$66.00	35.5%	8.3%	1.0134	8.4%	3.0%	0.0017	0.1484	0.02%	**3.0%**
11	Empire District Elec	$1.75	$1.20	$20.25	31.4%	8.6%	1.0205	8.8%	2.8%	0.0220	0.1900	0.42%	**3.2%**
12	Entergy Corp.	$6.00	$3.80	$65.75	36.7%	9.1%	1.0165	9.3%	3.4%	0.0004	0.2265	0.01%	**3.4%**
13	Eversource Energy	$3.75	$2.10	$38.00	44.0%	9.9%	1.0208	10.1%	4.4%	0.0043	0.2762	0.12%	**4.6%**
14	MGE Energy	$3.30	$1.35	$25.00	59.1%	13.2%	1.0312	13.6%	8.0%	0.0151	0.5000	0.76%	**8.8%**
15	NorthWestern Corp.	$3.50	$2.15	$37.00	38.6%	9.5%	1.0518	9.9%	3.8%	0.0532	0.2600	1.38%	**5.2%**
16	PG&E Corp.	$3.50	$2.10	$39.25	40.0%	8.9%	1.0312	9.2%	3.7%	0.0221	0.1737	0.38%	**4.1%**
17	Pub Sv Enterprise Grp	$3.25	$1.70	$30.75	47.7%	10.6%	1.0246	10.8%	5.2%	-	0.2313	0.00%	**5.2%**
18	SCANA Corp.	$4.75	$2.40	$45.50	49.5%	10.4%	1.0304	10.8%	5.3%	0.0100	0.1727	0.17%	**5.5%**
19	Sempra Energy	$6.25	$3.20	$56.50	48.8%	11.1%	1.0262	11.4%	5.5%	0.0100	0.3892	0.39%	**5.9%**
20	Vectren Corp.	$3.20	$1.80	$21.25	43.8%	15.1%	1.0139	15.3%	6.7%	0.0233	0.5526	1.29%	**8.0%**
21	Xcel Energy Inc.	$2.50	$1.45	$24.00	42.0%	10.4%	1.0248	10.7%	4.5%	0.0079	0.2000	0.16%	**4.6%**

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2013/14			2018/19			Chg	2018/19 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2013/14	2018/19	Growth
1	Alliant Energy	47.5%	$7,257	$3,447	49.5%	$7,800	$3,861	2.3%	$75.00	$55.00	$65.00	1.876	110.94	115.00	0.72%
2	Ameren Corp.	51.5%	$12,975	$6,682	54.0%	$15,700	$8,478	4.9%	$45.00	$35.00	$40.00	1.176	242.65	250.00	0.60%
3	Avista Corp.	48.6%	$2,670	$1,297	49.0%	$3,525	$1,727	5.9%	$35.00	$25.00	$30.00	1.121	60.08	64.50	1.43%
4	Black Hills Corp.	48.4%	$2,705	$1,309	46.5%	$3,500	$1,628	4.5%	$60.00	$40.00	$50.00	1.399	44.50	45.75	0.56%
5	CenterPoint Energy	36.0%	$12,550	$4,518	42.0%	$12,900	$5,418	3.7%	$30.00	$20.00	$25.00	2.083	430.00	450.00	0.91%
6	CMS Energy Corp.	31.0%	$11,846	$3,672	34.5%	$14,800	$5,106	6.8%	$40.00	$30.00	$35.00	1.972	275.20	285.00	0.70%
7	Consolidated Edison	51.5%	$24,525	$12,630	52.0%	$28,800	$14,976	3.5%	$70.00	$55.00	$62.50	1.225	293.00	293.00	0.00%
8	Dominion Resources	35.5%	$33,750	$11,981	42.0%	$42,700	$17,934	8.4%	$95.00	$70.00	$82.50	2.895	584.00	630.00	1.53%
9	DTE Energy Co.	50.0%	$16,675	$8,338	49.0%	$23,200	$11,368	6.4%	$90.00	$65.00	$77.50	1.314	177.00	192.00	1.64%
10	Duke Energy Corp.	50.5%	$81,500	$41,158	47.0%	$100,100	$47,047	2.7%	$90.00	$65.00	$77.50	1.174	707.00	712.00	0.14%
11	Empire District Elec	49.4%	$1,587	$784	50.0%	$1,925	$963	4.2%	$30.00	$20.00	$25.00	1.235	43.48	47.50	1.78%
12	Entergy Corp.	44.0%	$22,850	$10,054	46.5%	$25,500	$11,858	3.4%	$100.00	$70.00	$85.00	1.293	179.25	179.50	0.03%
13	Eversource Energy	54.5%	$18,275	$9,960	54.0%	$22,700	$12,258	4.2%	$60.00	$45.00	$52.50	1.382	317.00	322.00	0.31%
14	MGE Energy	62.5%	$1,055	$659	65.0%	$1,385	$900	6.4%	$55.00	$45.00	$50.00	2.000	34.67	36.00	0.76%
15	NorthWestern Corp.	46.5%	$2,216	$1,030	54.5%	$3,175	$1,730	10.9%	$60.00	$40.00	$50.00	1.351	38.75	47.00	3.94%
16	PG&E Corp.	52.5%	$27,311	$14,338	50.0%	$39,200	$19,600	6.5%	$55.00	$40.00	$47.50	1.210	456.67	500.00	1.83%
17	Pub Sv Enterprise Grp	59.0%	$20,575	$12,139	54.5%	$28,500	$15,533	5.1%	$45.00	$35.00	$40.00	1.301	506.00	506.00	0.00%
18	SCANA Corp.	45.5%	$11,000	$5,005	46.0%	$14,750	$6,785	6.3%	$65.00	$45.00	$55.00	1.209	143.00	149.00	0.83%
19	Sempra Energy	49.4%	$22,281	$11,007	48.5%	$29,500	$14,308	5.4%	$105.00	$80.00	$92.50	1.637	244.46	252.00	0.61%
20	Vectren Corp.	53.3%	$3,014	$1,606	52.0%	$3,550	$1,846	2.8%	$55.00	$40.00	$47.50	2.235	82.60	87.00	1.04%
21	Xcel Energy Inc.	46.7%	$20,477	$9,563	47.5%	$25,800	$12,255	5.1%	$35.00	$25.00	$30.00	1.250	497.97	514.00	0.64%

(a) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2018/19 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2018/19 BVPS.

CURRENT BOND YIELD

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP[1]	Beta	Weight	RP[2]	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$5,743	1.05%	11.3%
2	Atmos Energy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.85	75%	5.5%	7.6%	10.5%	$5,386	1.05%	11.6%
3	Laclede Group	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.6%	$2,187	1.63%	11.2%
4	New Jersey Resources	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$2,581	1.65%	11.9%
5	NiSource, Inc.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.85	75%	5.5%	7.6%	10.5%	$13,293	0.65%	11.2%
6	Northwest Natural Gas	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.6%	$1,242	1.77%	11.3%
7	Piedmont Natural Gas	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$2,862	1.65%	11.9%
8	South Jersey Industries	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$1,780	1.63%	11.8%
9	Southwest Gas Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.85	75%	5.5%	7.6%	10.5%	$2,592	1.65%	12.2%
10	WGL Holdings, Inc.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$2,684	1.65%	11.5%
	Average												**10.1%**			**11.6%**
	Midpoint (h)												**10.0%**			**11.7%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 10, 201

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015) and www.valueline.com (retrieved Mar. 10, 2015).

(c) Average yield on 30-year Treasury bonds for the six-months ending Feb. 2015 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.ht

(d) Morin, Roger A., "New Regulatory Finance,"*Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Mar. 6, 2015)

(f) www.valueline.com (retrieved Mar. 20, 2015)

(g) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).

(h) Average of low and high values

PROJECTED BOND YIELD

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				**Market**										**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**				**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*** [1]	**Beta**	**Weight**	***RP*** [2]	**Total RP**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	AGL Resources	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$5,743	1.05%	11.5%
2	Atmos Energy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.85	75%	4.6%	6.4%	10.7%	$5,386	1.05%	11.7%
3	Laclede Group	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	9.9%	$2,187	1.63%	11.5%
4	New Jersey Resources	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$2,581	1.65%	12.1%
5	NiSource, Inc.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.85	75%	4.6%	6.4%	10.7%	$13,293	0.65%	11.3%
6	Northwest Natural Gas	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	9.9%	$1,242	1.77%	11.7%
7	Piedmont Natural Gas	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$2,862	1.65%	12.1%
8	South Jersey Industries	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$1,780	1.63%	12.1%
9	Southwest Gas Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.85	75%	4.6%	6.4%	10.7%	$2,592	1.65%	12.3%
10	WGL Holdings, Inc.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.2%	$2,684	1.65%	11.8%
	Average												**10.4%**			**11.8%**
	Midpoint (h)												**10.3%**			**11.8%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 10, 201!
(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015) and www.valueline.com (retrieved Mar. 10, 2015).
(c) Average projected 30-year Treasury bond yield for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015); IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014).
(d) Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, Inc. at 190 (2006
(e) The Value Line Investment Survey (Mar. 6, 2015)
(f) www.valueline.com (retrieved Mar. 20, 2015)
(g) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).
(h) Average of low and high values

EMPIRICAL CAPM - CURRENT BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$ 6,783.7	0.94%	11.2%
2	Ameren Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$10,133.4	0.94%	10.8%
3	Avista Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$ 2,093.8	1.63%	11.8%
4	Black Hills Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.90	75%	5.8%	8.0%	10.9%	$ 2,221.1	1.63%	12.5%
5	CenterPoint Energy	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$ 8,914.0	0.94%	11.2%
6	CMS Energy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$ 9,293.5	0.94%	10.8%
7	Consolidated Edison	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.60	75%	3.9%	6.0%	8.9%	$17,982.3	0.65%	9.6%
8	Dominion Resources	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.6%	$40,768.6	-0.32%	9.2%
9	DTE Energy Co.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$13,884.9	0.65%	10.5%
10	Duke Energy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.60	75%	3.9%	6.0%	8.9%	$53,223.0	-0.32%	8.6%
11	Empire District Elec	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.6%	$ 1,060.0	1.77%	11.3%
12	Entergy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.6%	$13,700.0	0.65%	10.2%
13	Eversource Energy	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$15,726.6	0.65%	10.5%
14	MGE Energy	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.6%	$ 1,504.6	1.77%	11.3%
15	NorthWestern Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.70	75%	4.5%	6.7%	9.6%	$ 2,047.2	1.63%	11.2%
16	PG&E Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.65	75%	4.2%	6.3%	9.2%	$24,870.3	-0.32%	8.9%
17	Pub Sv Enterprise Grp	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$20,665.2	0.65%	10.5%
18	SCANA Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$ 7,585.0	0.94%	10.8%
19	Sempra Energy	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.75	75%	4.8%	7.0%	9.9%	$26,703.4	-0.32%	9.6%
20	Vectren Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.80	75%	5.2%	7.3%	10.2%	$ 3,592.3	1.65%	11.9%
21	Xcel Energy Inc.	2.3%	9.2%	11.5%	2.9%	8.6%	25%	2.2%	0.65	75%	4.2%	6.3%	9.2%	$17,411.9	0.65%	9.9%
	Average												**9.8%**			**10.6%**
	Midpoint (h)												**9.9%**			**10.6%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015)
(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from and http://finance.yahoo.com (retrievec Mar. 11, 2015).
(c) Average yield on 30-year Treasury bonds for the six-months ending Feb. 2015 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm. http://finance.yahoo.con (retrieved Mar. 11, 2015).
(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).
(f) www.valueline.com (retrieved Mar. 16, 2015)
(g) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).
(h) Average of low and high values

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$ 6,783.7	0.94%	11.4%
2	Ameren Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.2%	$10,133.4	0.94%	11.1%
3	Avista Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$ 2,093.8	1.63%	12.1%
4	Black Hills Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.90	75%	4.9%	6.7%	11.0%	$ 2,221.1	1.63%	12.6%
5	CenterPoint Energy	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$ 8,914.0	0.94%	11.4%
6	CMS Energy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.2%	$ 9,293.5	0.94%	11.1%
7	Consolidated Edison	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.60	75%	3.2%	5.0%	9.3%	$17,982.3	0.65%	10.0%
8	Dominion Resources	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	9.9%	$40,768.6	-0.32%	9.6%
9	DTE Energy Co.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.2%	$13,884.9	0.65%	10.8%
10	Duke Energy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.60	75%	3.2%	5.0%	9.3%	$53,223.0	-0.32%	9.0%
11	Empire District Elec	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	9.9%	$ 1,060.0	1.77%	11.7%
12	Entergy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	9.9%	$13,700.0	0.65%	10.5%
13	Eversource Energy	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.2%	$15,726.6	0.65%	10.8%
14	MGE Energy	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	9.9%	$ 1,504.6	1.77%	11.7%
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16	PG&E Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.65	75%	3.5%	5.3%	9.6%	$24,870.3	-0.32%	9.3%
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18	SCANA Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.2%	$ 7,585.0	0.94%	11.1%
19	Sempra Energy	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.2%	$26,703.4	-0.32%	9.8%
20	Vectren Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.4%	$ 3,592.3	1.65%	12.1%
21	Xcel Energy Inc.	2.3%	9.2%	11.5%	4.3%	7.2%	25%	1.8%	0.65	75%	3.5%	5.3%	9.6%	$17,411.9	0.65%	10.3%
	Average												**10.0%**			**10.9%**
	Midpoint (h)												**10.2%**			**10.8%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015)

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from and http://finance.yahoo.com (retrievec Mar. 11, 2015).

(c) Average yield on 30-year Treasury bonds for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015); IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).

(f) www.valueline.com (retrieved Mar. 16, 2015)

(g) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).

(h) Average of low and high values

CURRENT BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.50%
(b)	Single-A Utility Bond Yield	3.93%
	Change in Bond Yield	-4.57%
(c)	Risk Premium/Interest Rate Relationship	-0.4616
	Adjustment to Average Risk Premium	2.11%
(a)	Average Risk Premium over Study Period	3.34%
	Adjusted Risk Premium	**5.45%**
Implied Cost of Equity		
(b)	Triple-B Utility Bond Yield	4.62%
	Adjusted Equity Risk Premium	5.45%
	Risk Premium Cost of Equity	**10.07%**

(a) Avista/301, Schedule AMM-9, page 3.
(b) Average bond yield for six-months ending Feb. 2015 based on data from Moody's Investors Service at www.credittrends.com.
(c) Avista/301, Schedule AMM-9, page 4.

PROJECTED BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.50%
(b)	Single-A Utility Bond Yield 2015-19	6.15%
	Change in Bond Yield	-2.35%
(c)	Risk Premium/Interest Rate Relationship	-0.4616
	Adjustment to Average Risk Premium	1.08%
(a)	Average Risk Premium over Study Period	3.34%
	Adjusted Risk Premium	**4.43%**
Implied Cost of Equity		
(b)	Triple-B Utility Bond Yield 2015-19	6.84%
	Adjusted Equity Risk Premium	4.43%
	Risk Premium Cost of Equity	**11.27%**

(a) Avista/301, Schedule AMM-9, page 3.

(b) Based on data from IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.

(c) Avista/301, Schedule AMM-9, page 4.

AUTHORIZED RETURNS

Year	Qtr.		(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1980	1		13.45%	13.49%	-0.04%
	2		14.38%	12.87%	1.51%
	3		13.87%	12.88%	0.99%
	4		14.35%	14.11%	0.24%
1981	1		14.69%	14.77%	-0.08%
	2		14.61%	15.82%	-1.21%
	3		14.86%	16.65%	-1.79%
	4		15.70%	16.57%	-0.87%
1982	1		15.55%	16.72%	-1.17%
	2		15.62%	16.26%	-0.64%
	3		15.72%	15.88%	-0.16%
	4		15.62%	14.56%	1.06%
1983	1		15.41%	14.15%	1.26%
	2		14.84%	13.58%	1.26%
	3		15.24%	13.52%	1.72%
	4		15.41%	13.38%	2.03%
1984	1		15.39%	13.56%	1.83%
	2		15.07%	14.72%	0.35%
	3		15.37%	14.47%	0.90%
	4		15.33%	13.38%	1.95%
1985	1		15.03%	13.31%	1.72%
	2		15.44%	12.95%	2.49%
	3		14.64%	12.11%	2.53%
	4		14.44%	11.49%	2.95%
1986	1		14.05%	10.18%	3.87%
	2		13.28%	9.41%	3.87%
	3		13.09%	9.39%	3.70%
	4		13.62%	9.31%	4.31%
1987	1		12.61%	8.96%	3.65%
	2		13.13%	9.77%	3.36%
	3		12.56%	10.61%	1.95%
	4		12.73%	11.05%	1.68%
1988	1		12.94%	10.32%	2.62%
	2		12.48%	10.71%	1.77%
	3		12.79%	10.94%	1.85%
	4		12.98%	9.98%	3.00%
1989	1		12.99%	10.13%	2.86%
	2		13.25%	9.94%	3.31%
	3		12.56%	9.53%	3.03%
	4		12.94%	9.50%	3.44%
1990	1		12.60%	9.72%	2.88%
	2		12.81%	9.91%	2.90%
	3		12.34%	9.93%	2.41%
	4		12.77%	9.89%	2.88%
1991	1		12.69%	9.58%	3.11%
	2		12.53%	9.50%	3.03%
	3		12.43%	9.33%	3.10%
	4		12.38%	9.02%	3.36%
1992	1		12.42%	8.91%	3.51%
	2		11.98%	8.86%	3.12%
	3		11.87%	8.47%	3.40%
	4		11.94%	8.53%	3.41%
1993	1		11.75%	8.07%	3.68%
	2		11.71%	7.81%	3.90%
	3		11.39%	7.28%	4.11%
	4		11.15%	7.22%	3.93%
1994	1		11.12%	7.55%	3.57%
	2		10.81%	8.29%	2.52%
	3		10.95%	8.51%	2.44%
	4	(c)	11.64%	8.87%	2.77%
1995	2		11.00%	7.93%	3.07%
	3		11.07%	7.72%	3.35%
	4		11.56%	7.37%	4.19%
1996	1		11.45%	7.44%	4.01%
	2		10.88%	7.98%	2.90%
	3		11.25%	7.96%	3.29%
	4		11.32%	7.62%	3.70%

Year	Qtr.		(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1997	1		11.31%	7.76%	3.55%
	2		11.70%	7.88%	3.82%
	3		12.00%	7.49%	4.51%
	4	(c)	11.01%	7.25%	3.76%
1998	2		11.37%	7.12%	4.25%
	3		11.41%	6.99%	4.42%
	4		11.69%	6.97%	4.72%
1999	1		10.82%	7.11%	3.71%
	2	(c)	10.82%	7.48%	3.34%
	4		10.33%	8.05%	2.28%
2000	1		10.71%	8.29%	2.42%
	2		11.08%	8.45%	2.63%
	3		11.33%	8.25%	3.08%
	4		12.50%	8.03%	4.47%
2001	1		11.16%	7.74%	3.42%
	2	(c)	10.75%	7.93%	2.82%
	4		10.65%	7.68%	2.97%
2002	1		10.67%	7.65%	3.02%
	2		11.64%	7.50%	4.14%
	3		11.50%	7.19%	4.31%
	4		10.78%	7.15%	3.63%
2003	1		11.38%	6.93%	4.45%
	2		11.36%	6.40%	4.96%
	3		10.61%	6.64%	3.97%
	4		10.84%	6.35%	4.49%
2004	1		11.10%	6.09%	5.01%
	2		10.25%	6.48%	3.77%
	3		10.37%	6.13%	4.24%
	4		10.66%	5.94%	4.72%
2005	1		10.65%	5.74%	4.91%
	2		10.52%	5.52%	5.00%
	3		10.47%	5.51%	4.96%
	4		10.40%	5.82%	4.58%
2006	1		10.63%	5.85%	4.78%
	2		10.50%	6.37%	4.13%
	3		10.45%	6.19%	4.26%
	4		10.14%	5.86%	4.28%
2007	1		10.44%	5.90%	4.54%
	2		10.12%	6.09%	4.03%
	3		10.03%	6.22%	3.81%
	4		10.27%	6.08%	4.19%
2008	1		10.38%	6.15%	4.23%
	2		10.17%	6.32%	3.85%
	3		10.49%	6.42%	4.07%
	4		10.34%	7.23%	3.11%
2009	1		10.24%	6.37%	3.87%
	2		10.11%	6.39%	3.72%
	3		9.88%	5.74%	4.14%
	4		10.27%	5.66%	4.61%
2010	1		10.24%	5.83%	4.41%
	2		9.99%	5.61%	4.38%
	3		9.93%	5.09%	4.84%
	4		10.09%	5.34%	4.75%
2011	1		10.10%	5.60%	4.50%
	2		9.85%	5.38%	4.47%
	3		9.65%	4.81%	4.84%
	4		9.88%	4.37%	5.51%
2012	1		9.63%	4.39%	5.24%
	2		9.83%	4.23%	5.60%
	3		9.75%	3.98%	5.77%
	4		10.07%	3.93%	6.14%
2013	1		9.57%	4.18%	5.39%
	2		9.47%	4.23%	5.24%
	3		9.60%	4.74%	4.86%
	4		9.83%	4.76%	5.07%
2014	1		9.54%	4.56%	4.98%
	2		9.84%	4.32%	5.52%
	3		9.45%	4.20%	5.25%
	4		10.28%	4.03%	6.25%
Average			**11.84%**	**8.50%**	**3.34%**

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (Jan. 15, 2015, Jan. 24, 2002, Jan. 18, 1995, and Jan. 16, 1990).

(b) Moody's Investors Service.

(c) No decisions reported for following quarter.

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.940951
R Square	0.8853887
Adjusted R Square	0.8845334
Standard Error	0.0053141
Observations	136

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.029232317	0.029232	1035.169	6.78937E-65
Residual	134	0.003784048	2.82E-05		
Total	135	0.033016365			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072664	0.001301889	55.81425	1.18E-94	0.070089048	0.07523887	0.070089048	0.075238867
X Variable 1	-0.4615656	0.014345897	-32.174	6.79E-65	-0.489939274	-0.43319191	-0.48993927	-0.43319191

CAPM - CURRENT BOND YIELD

GAS GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	AGL Resources	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$5,743	1.05%	10.8%
2	Atmos Energy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.85	10.2%	$5,386	1.05%	11.3%
3	Laclede Group	2.3%	9.2%	11.5%	2.9%	8.6%	0.70	8.9%	$2,187	1.63%	10.6%
4	New Jersey Resources	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$2,581	1.65%	11.4%
5	NiSource, Inc.	2.3%	9.2%	11.5%	2.9%	8.6%	0.85	10.2%	$13,293	0.65%	10.9%
6	Northwest Natural Gas	2.3%	9.2%	11.5%	2.9%	8.6%	0.70	8.9%	$1,242	1.77%	10.7%
7	Piedmont Natural Gas	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$2,862	1.65%	11.4%
8	South Jersey Industries	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$1,780	1.63%	11.4%
9	Southwest Gas Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.85	10.2%	$2,592	1.65%	11.9%
10	WGL Holdings, Inc.	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$2,684	1.65%	11.0%
	Average							**9.7%**			**11.1%**
	Midpoint (g)							**9.6%**			**11.2%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 10, 2015).
(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015) and www.valueline.com (retrieved Mar. 10, 2015).
(c) Average yield on 30-year Treasury bonds for the six-months ending Feb. 2015 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm.
(d) The Value Line Investment Survey (Mar. 6, 2015).
(e) www.valueline.com (retrieved Mar. 20, 2015).
(f) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).
(g) Average of low and high values.

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	AGL Resources	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$5,743	1.05%	11.1%
2	Atmos Energy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.85	10.4%	$5,386	1.05%	11.5%
3	Laclede Group	2.3%	9.2%	11.5%	4.3%	7.2%	0.70	9.3%	$2,187	1.63%	11.0%
4	New Jersey Resources	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$2,581	1.65%	11.7%
5	NiSource, Inc.	2.3%	9.2%	11.5%	4.3%	7.2%	0.85	10.4%	$13,293	0.65%	11.1%
6	Northwest Natural Gas	2.3%	9.2%	11.5%	4.3%	7.2%	0.70	9.3%	$1,242	1.77%	11.1%
7	Piedmont Natural Gas	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$2,862	1.65%	11.7%
8	South Jersey Industries	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$1,780	1.63%	11.7%
9	Southwest Gas Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.85	10.4%	$2,592	1.65%	12.1%
10	WGL Holdings, Inc.	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$2,684	1.65%	11.4%
	Average							**10.0%**			**11.4%**
	Midpoint (g)							**9.9%**			**11.5%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 10, 2015).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015) and www.valueline.com (retrieved Mar. 10, 2015).

(c) Average projected 30-year Treasury bond yield for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015); IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1,

(d) The Value Line Investment Survey (Mar. 6, 2015).

(e) www.valueline.com (retrieved Mar. 20, 2015).

(f) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).

(g) Average of low and high values.

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Adjusted K_e
1	Alliant Energy	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$ 6,783.7	0.94%	10.7%
2	Ameren Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$ 10,133.4	0.94%	10.3%
3	Avista Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$ 2,093.8	1.63%	11.4%
4	Black Hills Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.90	10.6%	$ 2,221.1	1.63%	12.3%
5	CenterPoint Energy	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$ 8,914.0	0.94%	10.7%
6	CMS Energy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$ 9,293.5	0.94%	10.3%
7	Consolidated Edison	2.3%	9.2%	11.5%	2.9%	8.6%	0.60	8.1%	$ 17,982.3	0.65%	8.7%
8	Dominion Resources	2.3%	9.2%	11.5%	2.9%	8.6%	0.70	8.9%	$ 40,768.6	-0.32%	8.6%
9	DTE Energy Co.	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$ 13,884.9	0.65%	10.0%
10	Duke Energy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.60	8.1%	$ 53,223.0	-0.32%	7.7%
11	Empire District Elec	2.3%	9.2%	11.5%	2.9%	8.6%	0.70	8.9%	$ 1,060.0	1.77%	10.7%
12	Entergy Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.70	8.9%	$ 13,700.0	0.65%	9.6%
13	Eversource Energy	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$ 15,726.6	0.65%	10.0%
14	MGE Energy	2.3%	9.2%	11.5%	2.9%	8.6%	0.70	8.9%	$ 1,504.6	1.77%	10.7%
15	NorthWestern Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.70	8.9%	$ 2,047.2	1.63%	10.6%
16	PG&E Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.65	8.5%	$ 24,870.3	-0.32%	8.2%
17	Pub Sv Enterprise Grp	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$ 20,665.2	0.65%	10.0%
18	SCANA Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$ 7,585.0	0.94%	10.3%
19	Sempra Energy	2.3%	9.2%	11.5%	2.9%	8.6%	0.75	9.4%	$ 26,703.4	-0.32%	9.0%
20	Vectren Corp.	2.3%	9.2%	11.5%	2.9%	8.6%	0.80	9.8%	$ 3,592.3	1.65%	11.4%
21	Xcel Energy Inc.	2.3%	9.2%	11.5%	2.9%	8.6%	0.65	8.5%	$ 17,411.9	0.65%	9.1%
	Average							**9.2%**			**10.0%**
	Midpoint (g)							**9.4%**			**10.0%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015)

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from and http://finance.yahoo.com (retrieved Mar. 11, 2015).

(c) Average yield on 30-year Treasury bonds for the six-months ending Feb. 2015 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm. http://finance.yahoo.com (retrieved Mar. 11, 2015).

(d) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).

(e) www.valueline.com (retrieved Mar. 16, 2015)

(f) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).

(g) Average of low and high values.

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$ 6,783.7	0.94%	11.0%
2	Ameren Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$10,133.4	0.94%	10.6%
3	Avista Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$ 2,093.8	1.63%	11.7%
4	Black Hills Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.90	10.8%	$ 2,221.1	1.63%	12.4%
5	CenterPoint Energy	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$ 8,914.0	0.94%	11.0%
6	CMS Energy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$ 9,293.5	0.94%	10.6%
7	Consolidated Edison	2.3%	9.2%	11.5%	4.3%	7.2%	0.60	8.6%	$17,982.3	0.65%	9.3%
8	Dominion Resources	2.3%	9.2%	11.5%	4.3%	7.2%	0.70	9.3%	$40,768.6	-0.32%	9.0%
9	DTE Energy Co.	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$13,884.9	0.65%	10.4%
10	Duke Energy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.60	8.6%	$53,223.0	-0.32%	8.3%
11	Empire District Elec	2.3%	9.2%	11.5%	4.3%	7.2%	0.70	9.3%	$ 1,060.0	1.77%	11.1%
12	Entergy Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.70	9.3%	$13,700.0	0.65%	10.0%
13	Eversource Energy	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$15,726.6	0.65%	10.4%
14	MGE Energy	2.3%	9.2%	11.5%	4.3%	7.2%	0.70	9.3%	$ 1,504.6	1.77%	11.1%
15	NorthWestern Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.70	9.3%	$ 2,047.2	1.63%	11.0%
16	PG&E Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.65	9.0%	$24,870.3	-0.32%	8.7%
17	Pub Sv Enterprise Grp	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$20,665.2	0.65%	10.4%
18	SCANA Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$ 7,585.0	0.94%	10.6%
19	Sempra Energy	2.3%	9.2%	11.5%	4.3%	7.2%	0.75	9.7%	$26,703.4	-0.32%	9.4%
20	Vectren Corp.	2.3%	9.2%	11.5%	4.3%	7.2%	0.80	10.1%	$ 3,592.3	1.65%	11.7%
21	Xcel Energy Inc.	2.3%	9.2%	11.5%	4.3%	7.2%	0.65	9.0%	$17,411.9	0.65%	9.6%
	Average							**9.6%**			**10.4%**
	Midpoint (g)							**9.7%**			**10.4%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Mar. 11, 2015)

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from and http://finance.yahoo.com (retrieved Mar. 11, 2015).

(c) Average yield on 30-year Treasury bonds for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015); IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014).

(d) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).

(e) www.valueline.com (retrieved Mar. 16, 2015)

(f) Morningstar, "2015 Ibbotson SBBI Market Report," at Table 10 (2015).

(g) Average of low and high values.

GAS GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	AGL Resources	11.5%	1.0297	11.8%
2	Atmos Energy Corp.	10.5%	1.0354	10.9%
3	Laclede Group	8.5%	1.0357	8.8%
4	New Jersey Resources	12.0%	1.0316	12.4%
5	NiSource, Inc.	10.0%	1.0293	10.3%
6	Northwest Natural Gas	9.0%	1.0242	9.2%
7	Piedmont Natural Gas	10.5%	1.0219	10.7%
8	South Jersey Industries	14.5%	1.0371	15.0%
9	Southwest Gas Corp.	12.0%	1.0215	12.3%
10	WGL Holdings, Inc.	11.0%	1.0228	11.3%
	Average			**11.3%**
	Midpoint (d)			**11.9%**

(a) The Value Line Investment Survey (Mar. 6, 2015).
(b) Adjustment to convert year-end return to an average rate of return from Avista/301, Schedule AMM-4.
(c) (a) x (b).
(d) Average of low and high values.

COMBINATION GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	12.0%	1.0113	12.1%
2	Ameren Corp.	9.5%	1.0238	9.7%
3	Avista Corp.	8.5%	1.0286	8.7%
4	Black Hills Corp.	9.0%	1.0218	9.2%
5	CenterPoint Energy	12.5%	1.0182	12.7%
6	CMS Energy Corp.	13.5%	1.0329	13.9%
7	Consolidated Edison	9.0%	1.0170	9.2%
8	Dominion Resources	17.0%	1.0403	17.7%
9	DTE Energy Co.	10.0%	1.0310	10.3%
10	Duke Energy Corp.	8.0%	1.0134	8.1%
11	Empire District Elec	8.5%	1.0205	8.7%
12	Entergy Corp.	9.0%	1.0165	9.1%
13	Eversource Energy	9.5%	1.0208	9.7%
14	MGE Energy	13.5%	1.0312	13.9%
15	NorthWestern Corp.	9.5%	1.0518	10.0%
16	PG&E Corp.	9.5%	1.0312	9.8%
17	Pub Sv Enterprise Grp	10.5%	1.0246	10.8%
18	SCANA Corp.	10.5%	1.0304	10.8%
19	Sempra Energy	11.5%	1.0262	11.8%
20	Vectren Corp.	15.0%	1.0139	15.2%
21	Xcel Energy Inc.	10.0%	1.0248	10.2%
	Average			**10.7%**
	Midpoint (d)			**11.7%**

(a) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).

(b) Adjustment to convert year-end return to an average rate of return from Avista/301, Schedule AMM-6.

(c) (a) x (b).

(d) Average of low and high values.

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	Church & Dwight	Household Products	$ 85.02	$ 1.36	1.6%
2	Coca-Cola	Beverage	$ 41.36	$ 1.32	3.2%
3	Colgate-Palmolive	Household Products	$ 69.71	$ 1.54	2.2%
4	ConAgra Foods	Food Processing	$ 34.58	$ 1.00	2.9%
5	Gen'l Mills	Food Processing	$ 53.05	$ 1.76	3.3%
6	Kellogg	Food Processing	$ 63.47	$ 1.96	3.1%
7	Kimberly-Clark	Household Products	$ 108.34	$ 3.52	3.2%
8	McDonald's Corp.	Restaurant	$ 97.04	$ 3.40	3.5%
9	PepsiCo, Inc.	Beverage	$ 96.86	$ 2.71	2.8%
10	Procter & Gamble	Household Products	$ 84.04	$ 2.58	3.1%
11	Smucker (J.M.)	Food Processing	$ 113.32	$ 2.59	2.3%
12	Verizon Com.	Telecommunications	$ 48.97	$ 2.20	4.5%
13	Wal-Mart Stores	Retail Store	$ 83.20	$ 1.96	2.4%
	Average				**2.9%**

(a) Average of closing prices for 30 trading days ended Mar. 27, 2015.
(b) The Value Line Investment Survey, *Summary & Index* (Mar. 27, 2015).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth Rates		
	Company	**V Line**	**IBES**	**Zacks**
1	Church & Dwight	9.0%	9.68%	9.73%
2	Coca-Cola	6.0%	4.87%	6.96%
3	Colgate-Palmolive	11.0%	8.23%	8.38%
4	ConAgra Foods	7.0%	8.30%	7.30%
5	Gen'l Mills	6.0%	6.12%	6.66%
6	Kellogg	6.0%	4.40%	6.67%
7	Kimberly-Clark	9.5%	7.00%	6.64%
8	McDonald's Corp.	4.0%	6.44%	8.27%
9	PepsiCo, Inc.	8.5%	6.77%	6.99%
10	Procter & Gamble	7.5%	6.67%	7.40%
11	Smucker (J.M.)	6.5%	5.50%	5.65%
12	Verizon Com.	8.0%	7.88%	8.38%
13	Wal-Mart Stores	6.5%	4.68%	5.19%

(a) The Value Line Investment Survey (Feb. 27, Jan. 23, Jan. 30, Mar. 20, & Mar. 27, 2015).
(b) www.finance.yahoo.com (retrieved Mar. 12, 2015).
(c) www.zacks.com (Retrieved Mar. 12, 2015).

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)
		Cost of Equity Estimates		
	Company	**V Line**	**IBES**	**Zacks**
1	Church & Dwight	10.6%	11.3%	11.3%
2	Coca-Cola	9.2%	8.1%	10.2%
3	Colgate-Palmolive	13.2%	10.4%	10.6%
4	ConAgra Foods	9.9%	11.2%	10.2%
5	Gen'l Mills	9.3%	9.4%	10.0%
6	Kellogg	9.1%	7.5%	9.8%
7	Kimberly-Clark	12.7%	10.2%	9.9%
8	McDonald's Corp.	7.5%	9.9%	11.8%
9	PepsiCo, Inc.	11.3%	9.6%	9.8%
10	Procter & Gamble	10.6%	9.7%	10.5%
11	Smucker (J.M.)	8.8%	7.8%	7.9%
12	Verizon Com.	12.5%	12.4%	12.9%
13	Wal-Mart Stores	8.9%	7.0%	7.5%
	Average (b)	**10.3%**	**9.6%**	**10.2%**
	Midpoint (c)	**10.4%**	**9.7%**	**10.2%**

(a) Sum of dividend yield (Avista/301, Schedule AMM-14, p. 1) and respective growth rate (Avista/301,
(b) Excludes highlighted figures.
(c) Average of low and high values.

GAS GROUP

	Company	Mechanism
1	AGL Resources, Inc.	PGA, RDM, WNA, ICR, DSM, Cost tracker for environmental remediation
2	Atmos Energy Corp.	PGA, WNA, ICR, BDR, Annual rate filing mechanism, Enhanced rate design
3	Laclede Group	PGA, WNA, ICR
4	New Jersey Resources	PGA, RDM, ICR, Cost trackers for environmental remediation and energy efficiency programs
5	NiSource, Inc.	PGA, RDM, WNA, ICR, BDR, Tax rider, Surcharge for conservation and energy efficiency programs, Cost tracker for environmental remediation
6	Northwest Natural Gas	PGA, RDM, WNA, ICR, Cost tracker for environmental remediation
7	Piedmont Natural Gas	PGA, RDM, WNA, ICR, Rate stabilization mechanism to reduce regulatory lag
8	South Jersey Industries	PGA, RDM, ICR, Cost trackers for environmental remediation and energy efficiency programs
9	Southwest Gas	PGA, RDM
10	WGL Holdings, Inc.	PGA, RDM, WNA, ICR, DSM, PCR

BDR -- Bad Debt Cost Recovery Rider
DSM -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Power Cost Adjustment Clause
ICR -- Infrastructure Investment / Renewables Cost Recovery Mechanism
PCR -- Pension Cost Recovery Mechanism
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
SCR - Storm Cost Recovery Tracker
TCR -- Transmission Cost Recovery Tracker
WNC -- Weather Normalization Clause or other mitigants

Source : 2013 Form 10-K Reports

COMBINATION GROUP

	Company	Mechanism
1	Alliant Energy	FCA, PGA, FTY, TCR, ICR, DSM
2	Ameren Corp.	FCA, PGA, ICR, DSM, ECA, BDR
3	Avista Corp.	FCA, PGA
4	Black Hills Corp.	FCA, PGA, ICR, ECA, TCR, WNA, Construction financing rider to recover financing costs in lieu of AFUDC
5	CenterPoint Energy	PGA, ICR, RDM, WNA
6	CMS Energy Corp.	FCA, PGA, RDM, FTY
7	Consolidated Edison	FCA, PGA, RDM, WNA, FTY, PCR, SCR
8	Dominion Resources	FCA, PGA, ICR, TCR, DSM
9	DTE Energy Co.	FCA, PGA, RDM, FTY, ICR, DSM, BDR, SCR
10	Duke Energy Corp.	FCA, FTY, ICR, DSM, ECA, SCR
11	Empire District Elec	FCA, PGA, DSM, TCR, PCR, Hybrid Test Year, other O&M trackers
12	Entergy Corp.	FCA, PGA, FTY, SCR, DSM, Pre-Approval rider for generating facility
13	Eversource Energy	RDM, PGA, ICR, DSM, FTY, PCR, TCR, SCR, other trackers related to residential assistance, solar projects, net-metering facilities, smart grid, and safety and reliability programs
14	MGE Energy	FAC, PGA, FTY
15	NorthWestern Corp.	FCA, PGA, Investment Pre-Approval, Property tax tracker
16	PG&E Corp.	FCA, RDM, FTY
17	Pub Sv Enterprise Group	FCA, PGA, WNA, ICR, DSM
18	SCANA Corp.	FCA, PGA, RDM, ICR, DSM, PCR, SCR
19	Sempra Energy	FCA, RDM, FTY
20	Vectren Corp.	FCA, PGA, RDM, WNA, ICR, DSM, TCR
21	Xcel Energy Inc.	FCA, PGA, ECA, ICR, FTY, DSM, TCR, Capacity clause to recover capacity payments for purchased power, residential assistance trackers

BDR -- Bad Debt Cost Recovery Rider
DSM -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Power Cost Adjustment Clause
FTY - Jurisdiction allows for future test year
ICR -- Infrastructure Investment / Renewables Cost Recovery Mechanism
PCR -- Pension Cost Recovery Mechanism
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
SCR - Storm Cost Recovery Tracker
TCR -- Transmission Cost Recovery Tracker
WNC -- Weather Normalization Clause or other mitigants

Source : 2013 Form 10-K Reports, Edison Electric Institute, Forward Test Years for US Electric Utilities (Aug. 2010).

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

ADRIEN M. MCKENZIE
Exhibit No. 302

Qualifications of Adrien M. McKenzie

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. What is the purpose of this exhibit?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. Please describe your qualifications and experience.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Since 2014, I have personally sponsored direct and rebuttal testimony concerning the rate of return on equity ("ROE") in proceedings filed with the Federal Energy Regulatory Commission ("FERC" or "the Commission"), the Hawaii Public Utilities Commission, the Kansas State Corporation Commission, the Kentucky Public Service Commission, the Montana Public Service Commission, the Oregon Public Utilities Commission, the South Dakota Public Utilities Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair ROE for regulated electric and gas utility operations.

In addition, over the course of my career I have worked with Dr. William Avera to prepare prefiled direct and rebuttal testimony in over 250 regulatory proceedings before the Federal Energy Regulatory Commission ("FERC") (including Docket No. EL11-66-001, which established FERC's current policies with respect to ROE for electric utilities, adopted in Opinion No. 531), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states.[1] In connection with these assignments, my responsibilities have included performing analyses to estimate investors' required rate of return, critically evaluating the results of alternative approaches, evaluating the positions of other parties, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs. Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. A resume containing the details of my qualifications and experience is attached below.

[1] This testimony was sponsored by Dr. William Avera, who is President of FINCAP, Inc.

ADRIEN M. McKENZIE

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Economic and Financial Counsel

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA) designation. He has over 25 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

Consultant, FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014)

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012)

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in 33 states, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of ROE. Many of these proceedings have been influential in addressing key aspects of FERC's policies with respect to ROE determinations. Broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF JODY MOREHOUSE
REPRESENTING AVISTA CORPORATION

Natural Gas Supply

I. INTRODUCTION

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

A. My name is Jody Morehouse and I am employed as Director of Gas Supply for Avista Utilities (Avista or Company). In my current role I am responsible for Avista's natural gas supply and upstream pipeline transportation resources. My business address is 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. I graduated from Montana State University with a Bachelor of Science Degree in Mechanical Engineering and hold a professional engineering license in the State of Washington. I joined the Company in 1989 and have held staff and management positions in our natural gas engineering, natural gas operations, natural gas planning, and natural gas measurement departments. Additionally, I held the position of Manager of Pipeline Integrity and Compliance prior to my current role.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe Avista's natural gas resource planning process, provide an overview of the Jackson Prairie natural gas storage facility, and provide an overview on the Company's 2014 Natural Gas Integrated Resource Plan. A table of contents for my testimony is as follows:

Description		Page
I.	Introduction	1
II.	Planning for Commodity Resource Procurement	3
III.	Jackson Prairie Storage	9
IV.	2014 Natural Gas Integrated Resource Plan	11

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 401 which is a copy of the Company's 2014 Natural Gas Integrated Resource Plan which was acknowledged by this Commission on March 2, 2015.

Q. Is the Company proposing any changes to the cost of natural gas for its retail natural gas customers in this case?

A. No, Avista is not proposing changes in this filing related to the commodity cost of natural gas or upstream pipeline transportation resource costs. Changes in the commodity cost of natural gas, and the cost of natural gas pipeline transportation included in customers' rates are addressed in the Company's annual Purchased Gas Cost Adjustment (PGA) filing. The Company filed its annual PGA on July 31, 2014 (updated on September 15, 2014), with new rates effective November 1, 2014.

Q. What is the Company's current expectations related to the PGA that the Company will file in July 2015?

A. The most current estimate for the PGA that the Company will file in July, with a proposed effective date of November 1, 2015, is for an approximate 10% billing rate decrease, barring any major change in the forward wholesale price of natural gas.

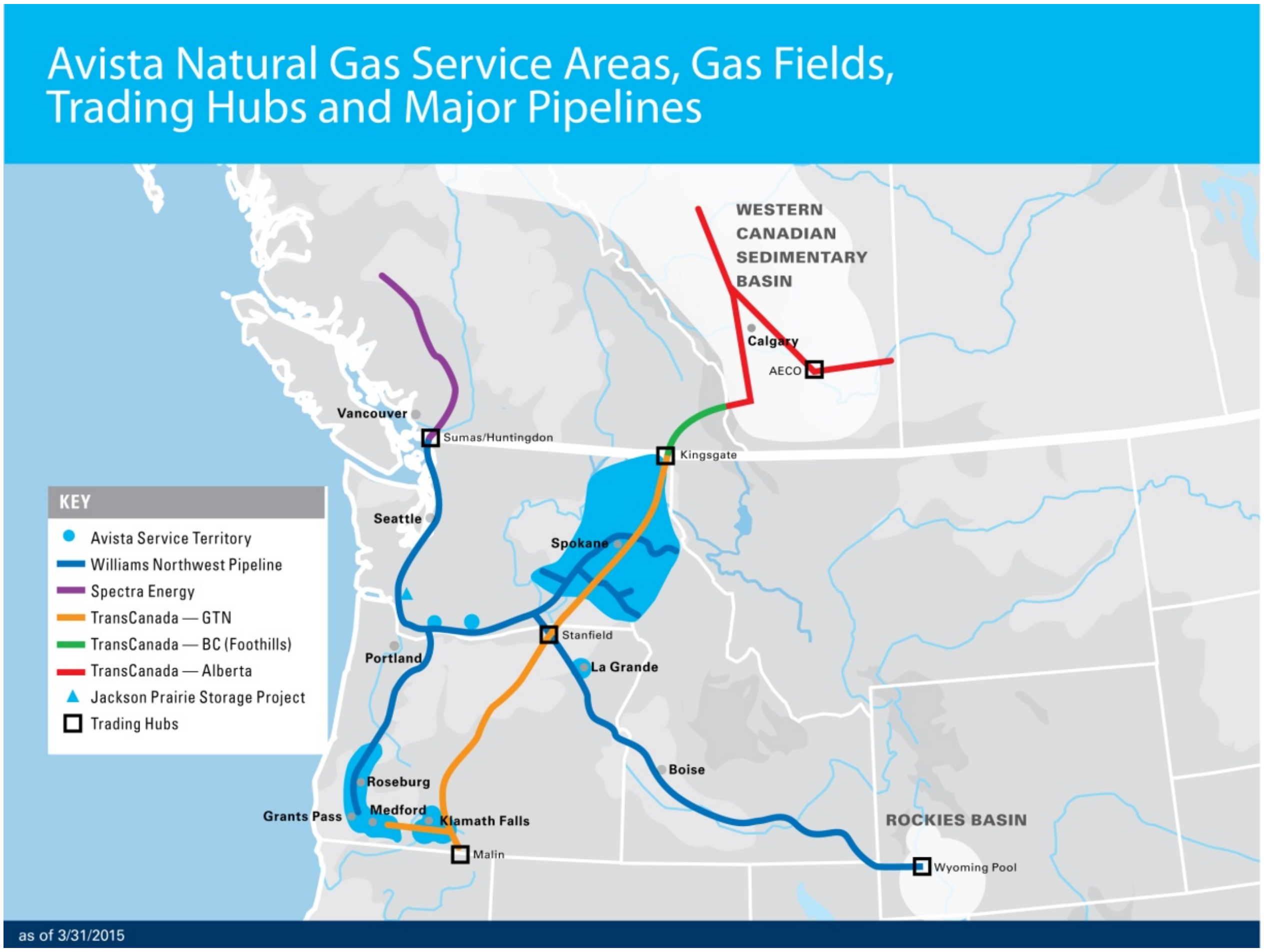
II. PLANNING FOR COMMODITY RESOURCE PROCUREMENT

Q. Please describe Avista's natural gas portfolio as it relates to the procurement of natural gas for its local distribution company ("LDC") customers?

A. Avista purchases natural gas for its distribution customers in wholesale markets at multiple supply basins in the western United States and western Canada. Purchased natural gas can be transported through six connected pipelines on which Avista holds firm contractual transportation rights. These contracts provide access to both US and Canadian-sourced supply. The US-sourced natural gas represents approximately 25% of the contractual rights and provides transportation from the Rocky Mountains. The remaining 75% provides access to Alberta and British Columbia natural gas supply basins. This diverse portfolio of natural gas resources allows the Company to make natural gas procurement decisions based on the reliability and economics that provide the most benefit to our customers. As natural gas prices in the Pacific Northwest can be affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada, future prices and delivery constraints may cause the source mix to vary.

Illustration No. 1 below is a map showing our service territory, natural gas trading hubs, interstate pipelines, and natural gas storage facilities:

<u>Illustration No. 1</u>:



Future natural gas prices cannot be accurately predicted. Market conditions, analysis, and experience shape our overall procurement approach. The Company's goal is to provide reliable supply at competitive prices, with some level of price certainty, in a volatile commodity market. To that end, the Company utilizes a Procurement Plan which includes hedging (on both a short-term and long-term basis), storage utilization, and index purchases. This approach is diversified by transaction time, term, counterparty, and supply basin. The Procurement Plan is disciplined, yet flexible, and layers in fixed-price purchases over time and term to provide a level of price certainty to customers. The Company provides in its annual PGA filing a copy of its Natural Gas Procurement Plan.

The Procurement Plan provides a process that fixes future gas prices for a targeted portion of the portfolio through the use of hedge windows. The hedge windows are "open" for a predetermined time period and have upper and lower pricing levels which are determined by the market at the time the window becomes effective. In a rising market, this reduces exposure to extreme price spikes. In a declining market, it can facilitate locking in lower prices. These windows can be executed, or "closed" if certain pricing levels are met, or upon time expiration if no pricing events occur. The Company always maintains some level of discretion and may choose not to execute within a window or to change some aspect of a window given market conditions.

In addition, a portion of the portfolio that is separate from the defined hedge windows is designated as discretionary. This opportunistic portion of the portfolio allows the Company to hedge additional, targeted volumes in gas years beyond the prompt year at potentially favorable pricing levels. In the event those pricing levels are not reached, the unexecuted volumes designated as discretionary hedges will become a part of the prompt year hedging program.

The Gas Supply department continuously monitors the results of the Procurement Plan, evolving market conditions, variation in demand profiles, new supply opportunities, and regulatory conditions. Although various windows and targets are established in the initial design phase of the portfolio, the plan provides flexibility to exercise judgment to revise and/or adjust the Procurement Plan in response to changing conditions. Material changes to the Procurement Plan are communicated to Avista's Senior Management and periodically to Commission Staff.

Natural Gas Supply

Q. What delivery period does the natural gas Procurement Plan include?

A. The Procurement Plan includes four complete natural gas operating years (November through October) and whole months remaining from the current month until the next October 31 period (the current natural gas operating year). The four complete upcoming natural gas operating years are designated “Prompt”, “Second”, “Third”, and “Fourth” years.

Q. Please describe the components of the natural gas Procurement Plan.

A. Each year a comprehensive review of the previous year’s plan is performed. The review includes analysis of historical and forecasted market trends, fundamental market analysis, demand forecasting, and transportation, storage and other resource considerations. The plan includes the following components:

1. **Previous Year(s) Hedges** – longer-term fixed-price purchases executed as a part of a previous year’s Procurement Plan.
2. **Prompt Year Hedges** – the portion of the portfolio addressed through the utilization of hedge windows. In each window, fixed price purchases are made for various prompt year delivery periods (i.e., November to March winter purchase, April to October summer purchase, or individual months). Prior to the execution of each window, market conditions, fundamental market knowledge, and other information are considered to determine if execution will occur.
3. **Storage Withdrawals** – utilizing the capacity and deliverability from the Jackson Prairie natural gas storage facility, Avista is able to inject natural gas during the summer months and withdraw it to serve customers during the higher demand winter months.

4. **<u>Discretionary Long-term Hedges</u>** – purchases based on a set of price levels, or targets, which trigger possible execution. At the time the triggers are reached, evaluation of market conditions, fundamental market knowledge, and other information are considered. These hedges will generally be executed when they can be done at or below the established targets.

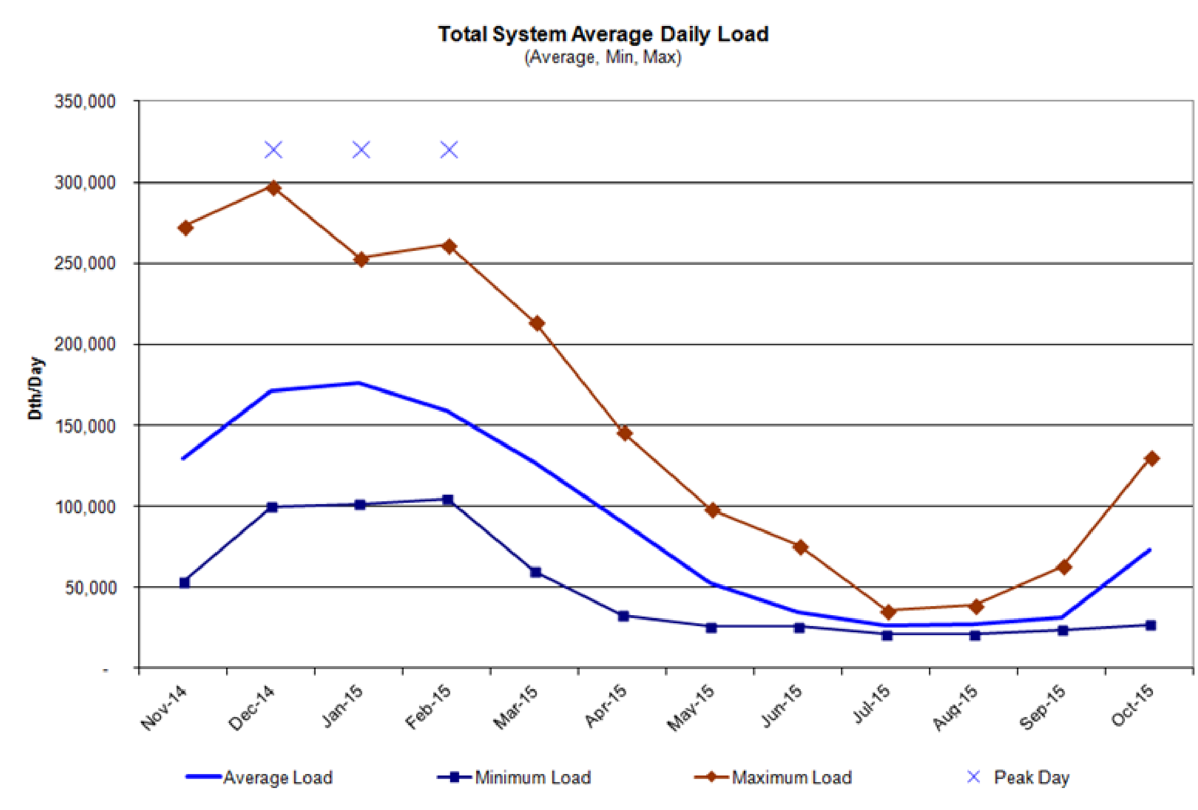
5. **<u>Index Purchases</u>** – physical index-based natural gas purchases are procured prior to or throughout the delivery month. These purchases are usually associated with daily pricing. The amount of index purchases planned is the difference between the forecasted demand less the sum of the previous year hedges, prompt year hedges, and storage withdrawals.

Q. Please describe how the Procurement Plan manages volatility.

A. The Procurement Plan focuses on managing the costs associated with serving varying retail load with supply from a wholesale market with price volatility. For example, system-wide <u>*average*</u> daily demand can fluctuate between 27,000 dekatherms (Dth) per day during a <u>summer</u> month, and 180,000 Dth/day during a <u>winter</u> month. Further, December's system-wide daily demand volatility has ranged from a low of 99,000 Dth/day to a high of 300,000 Dth/Day. Finally, from Avista's 2014 IRP, system-wide peak day demand for 2015-2016 heating season is forecasted to be approximately 339,000 Dth per day.

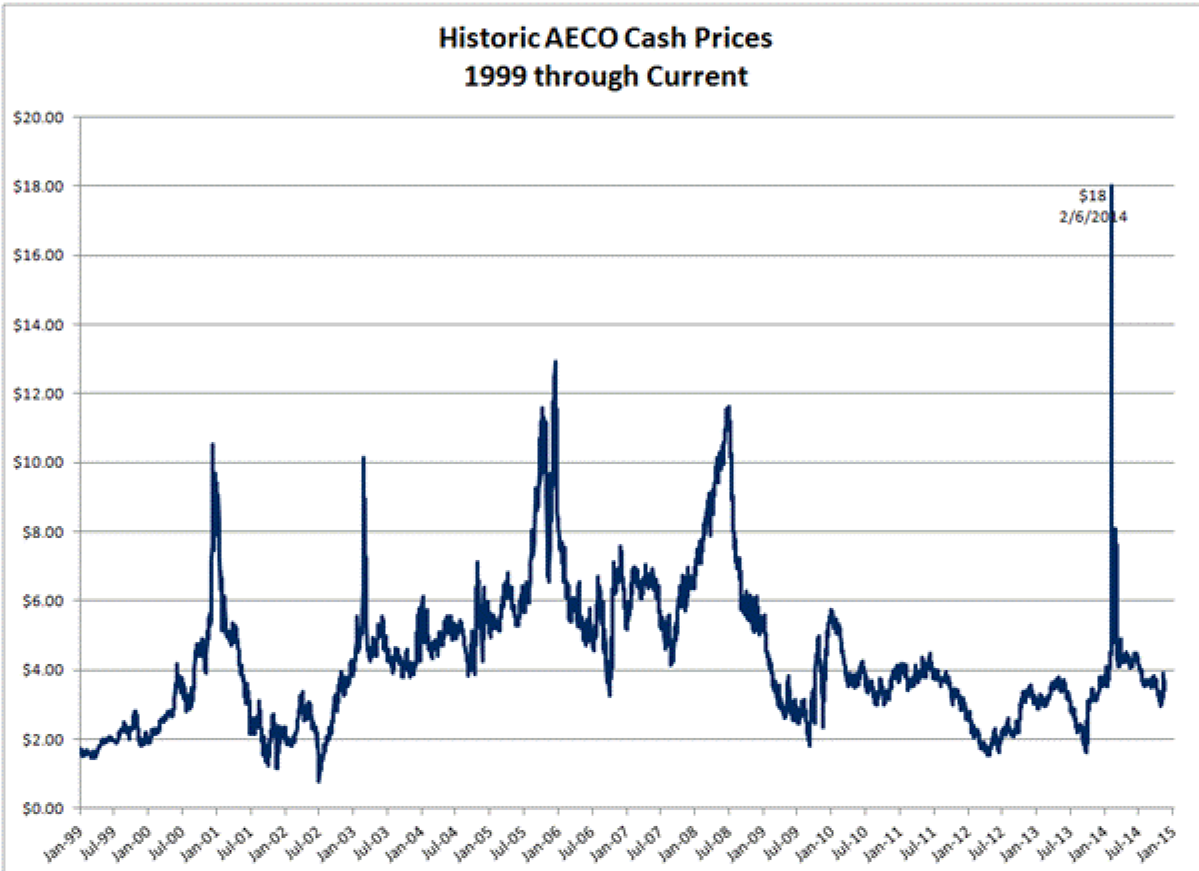
In order to manage these seasonal, monthly and daily volume swings, Avista shapes the components of the Procurement Plan by month (i.e. more natural gas is hedged for the winter months than for the summer). Illustration No. 2 below shows the demand volatility:

<u>Illustration No. 2</u>:



Price volatility can also vary widely by season, month and day. Illustration No. 3, below, includes a chart depicting natural gas price volatility over time.

Illustration No. 3:



Avista cannot predict with accuracy what natural gas prices may be. Our experience and intelligence related to market fundamentals guide our procurement decisions. By layering in fixed price purchases over time, setting upper and lower pricing levels on the hedge windows, opportunistically hedging at pricing levels through the discretionary hedge program, and actively managing storage resources, Avista is able to meet our goal of providing a meaningful measure of price stability and certainty, and competitive prices for our customers.

III. JACKSON PRAIRIE STORAGE

Q. Please describe Avista's involvement with the Jackson Prairie natural gas

storage facility?

A. Avista is one of the three original developers of the underground storage facility at Jackson Prairie, which is located near Chehalis, Washington. Although there have been corporate changes due to mergers, acquisitions and name changes, Avista, Puget Sound Energy and Williams Northwest Pipeline each hold a one-third share (equal, undivided interest) of this underground gas storage facility through a joint ownership agreement. Puget Sound Energy is the operator of the facility.

Q. What type of storage facility is Jackson Prairie?

A. Jackson Prairie is an underground aquifer storage facility. Storage and the associated withdrawal and injection capability has been created by a combination of wells, gathering pipelines, compression and dehydration equipment, and the removal and disposal of aquifer water.

Q. Please describe the present level of storage that Avista owns at Jackson Prairie.

A. At the present time, Avista Utilities <u>owns</u> a total of 8,528,013 dekatherms (Dth) of capacity. This capacity comes with a withdrawal capability of 398,667 Dth per day (deliverability). Oregon’s current share of that capacity is 823,337 Dth and 52,000 Dth of deliverability. Additionally, the Company has <u>leased</u> 95,565 Dth of capacity (2,623 Dth of deliverability) from Williams Northwest Pipeline for the benefit of Oregon customers. The <u>combined</u> leased and owned storage provides Oregon Customers storage capacity of 918,902 Dth and deliverability of 54,623 Dth per day.

Q. What are the benefits of storage to Avista’s customers?

A. Access to regionally located storage provides several benefits to Avista customers. It enables the Company to capture seasonal price spreads (differentials) between summer and winter, improves reliability of supply, increases operational flexibility, mitigates peak demand price spikes, and provides numerous other economic benefits.

IV. 2014 NATURAL GAS INTEGRATED RESOURCE PLAN

Q. Please provide an overview of the Company's development of its 2014 Natural Gas Integrated Resource Plan?

A. The 2014 Integrated Resource Plan (IRP) was filed with the Commission on August 29, 2014. The IRP includes forecasts of natural gas demand and any supply-side transportation resources and demand-side measures needed for the coming 20 years, which will help Avista continue to reliably provide natural gas to our customers. A copy of the Company's 2014 Natural Gas Integrated Resource Plan is included as Exhibit No. 401.

Q. What are the summary highlights from the 2014 IRP?

A. Highlights from the 2014 IRP are as follows:

- The Company has sufficient natural gas pipeline resources well into the future with resource needs not occurring during the 20 year planning horizon in Oregon, Idaho or Washington;
- Natural Gas commodity prices continue to be relatively stable due to robust North American supplies led by shale gas development; and
- As forecasted demand is relatively flat, the Company will monitor actual demand for signs of increased growth which could accelerate resource needs.

Q. Has the Company's 2014 IRP been acknowledged by the Commission?

A. Yes, on March 2, 2015, the Commission acknowledged the 2014 Natural Gas IRP (Order No. 15-063), finding the IRP was in compliance with Oregon Commission guidelines.

Q. When will the Company file its next IRP?

A. The Company will file its next IRP on or before August 31, 2016. A courtesy work plan will be filed August 31, 2015, detailing Avista's IRP planning process, as well as tentative dates and content for meetings with the Technical Advisory Group (TAC), which includes Commission Staff. TAC meetings will begin in the first quarter of 2016.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF JENNIFER S. SMITH
REPRESENTING AVISTA CORPORATION

Revenue Requirement and Allocations

I. INTRODUCTION

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

A. My name is Jennifer S. Smith. I am employed by Avista Corporation as a Senior Regulatory Analyst in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Would you please describe your educational background and professional experience?

A. I am a 2002 graduate of Washington State University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting and Accounting Information Systems. After spending eight years in the public accounting sector, I was hired into the State and Federal Regulation Department as a Regulatory Analyst in January of 2010. In my current role as a Senior Regulatory Analyst, I assist in the preparation of normalized revenue requirement and pro forma studies for all jurisdictions in which the Company provides utility services. I am also responsible for, among other things, annual filings and various applications related to affiliated interest issues and subsidiary operations.

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 the 2016 test year operating results, including expense and rate base adjustments made to the 2014 base year operating results and rate base.

The net operating income and rate base that serve as the basis for the overall revenue requirement in this filing incorporate not only those adjustments prepared by myself, but also by Company witnesses Ms. Schuh and Mr. Ehrbar. I will provide a summary of the Company's restated 2014 net plant, and planned 2015 and 2016 capital additions adjustments, while Ms. Schuh will present more detail for each of these adjustments in her testimony. I will also cover the revenue load adjustment briefly, while Mr. Ehrbar provides a more in-depth discussion. Finally, I will provide an overview of the Company's system and jurisdictional allocation methodologies that have been in place for several years.

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

A. Yes. I am sponsoring Exhibit Nos. 501-502, which were prepared under my direction. Exhibit No. 501 consists of worksheets, which show summary level historical actual 2014 base year operating results, test year results for 2016 including proposed natural gas operating results and rate base for the Company's Oregon jurisdiction, the Company's calculation of the general revenue requirement, the derivation of the net operating income to gross revenue conversion factor, and the restating and forecasted adjustments proposed in this filing. Exhibit No. 502 consists of worksheets similar to Exhibit No. 501 on a more detailed level (by FERC account).

II. REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

Q. Would you please summarize the Company's need for a revenue increases for its natural gas operating system for the Oregon jurisdiction?

A. Yes. After taking into account all historical restating and forecasted adjustments, the natural gas rate of return ("ROR") for the Company's Oregon jurisdictional operations for the 2016 test year is 5.44%, as shown on Exhibit No. 501, page 1. This return level is below the Company's requested rate of return of 7.72%. The incremental revenue requirement for base retail rates, necessary to give the Company an opportunity to earn its requested ROR, is $8,557,000. The overall base natural gas revenue increase associated with the Company's request is 8.0%.

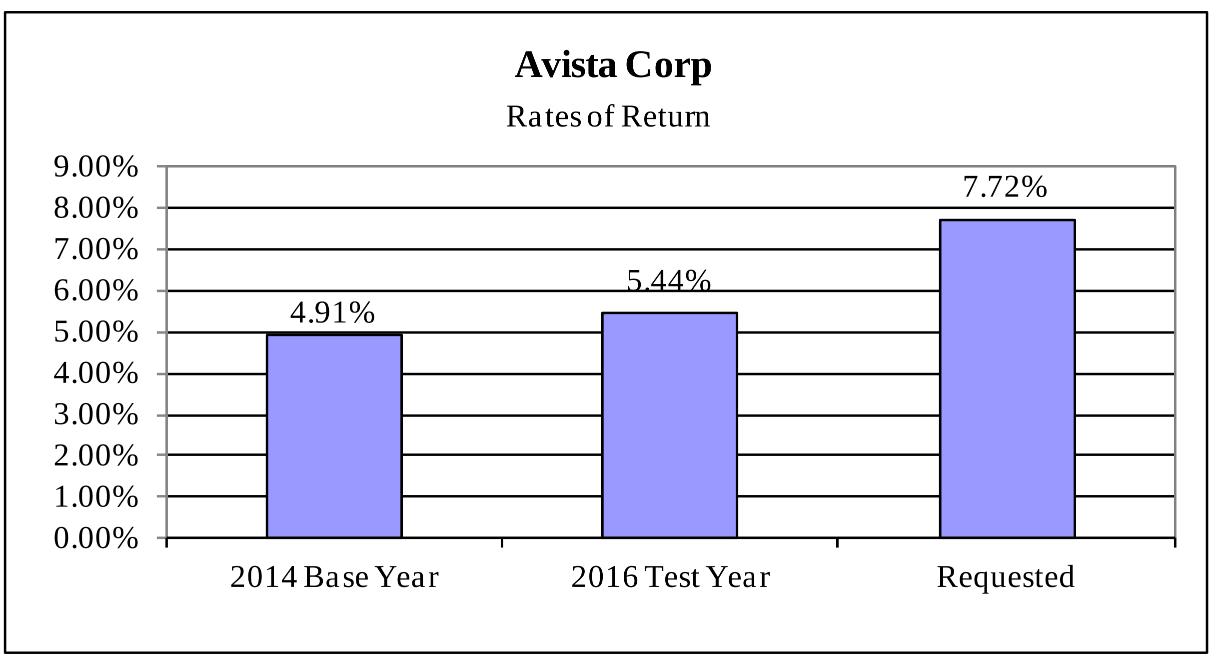
Q. What was the Company's rate of return that was last authorized by this Commission for its natural gas operations in Oregon?

A. The Company's currently authorized rate of return for its Oregon operations is 7.52%, effective April 16, 2015.

Q. By way of summary, could you please explain the different rates of return that you will be presenting in your testimony?

A. Yes. As shown in Illustration No.1 below, there are three different rates of return that will be discussed. The actual ROR earned by the Company during the twelve months ended December 31, 2014, the 2016 test year ROR determined in my Exhibit No. 501, page 1, and the requested ROR.

Illustration No. 1:



Q. What is the test year the Company is utilizing for this general rate request?

A. The test year being used by the Company is the twelve months ended December 31, 2016, presented on a forecasted basis. Currently authorized rates are based upon the 2015 forecasted test year utilized in Docket No. UG-284.

Q. Why did the Company use the year ending December 31, 2016 as the test year?

A. The test year in this case was selected to best reflect the conditions during which time the new rates will be in effect. Rates from this proceeding are expected to be effective in the first half of 2016. Although the use of the 2016 calendar-year rate period will likely understate the costs the Company will incur to serve customers during the full time period new rates will be in effect from this filing, it provides a reasonable basis for the calculation of revenue requirement in this case.

Q. Please explain how the Company developed the revenue requirement for the 2016 test year.

A. Revenue requirement preparation began with the historical accounting information for the twelve months ended December 31, 2014. Each of the revenue requirement components in the historical year was analyzed to determine if a normalizing or correcting adjustment was warranted to reflect normal operating conditions. The restated historical information was then adjusted to recognize known, measurable and anticipated events to determine a 2016 test year. Next, the 2016 test year results were adjusted to include previous Commission–ordered restating adjustments, resulting in restated 2016 test year results.

Q. Why did the Company begin with historical information?

A. The Company began with historical information and made adjustments to arrive at the restated 2016 test year revenue requirement, because starting with historical information provides a solid foundation that is easily auditable.

Q. Please summarize the process used to adjust the historical information to reflect the 2016 test year revenues and costs.

A. Revenues are adjusted for the effect of applying the current Commission-approved tariff rates to the 2016 test year customer usage. Historical operations and maintenance ("O&M") expenses were separated into labor and non-labor components. Except for a few specific cost items, non-labor costs were adjusted using the most current consumer price index (CPI). Historical labor costs were also adjusted for increases through the 2016 test year. Specific adjustments are described in further detail later in my testimony and shown in Exhibit Nos. 501 and 502.

III. NEED FOR ADDITIONAL RATE RELIEF

Q. Why is Avista requesting a revenue increase shortly after the conclusion of its last rate case?

A. As explained by Mr. Morris, the recent revenue increase approved effective April 16, 2015 addressed the under-recovery of utility costs the Company had experienced up to April 16, 2015, and a portion of the increased costs the Company will incur for the future rate period beginning April 16, 2015. For the calendar-year 2014, Avista's earned return on equity was approximately 7.2%, on a normalized basis, which is well below the previously approved authorized return for the Company. In addition, the new revenues effective April

16, 2015 cover the cost associated with new utility plant investment only through March 31, 2015. Therefore, additional revenues from this case are necessary to cover the costs associated with significant new plant investment subsequent to March 31, 2015, as well as increased operating costs for the 2016 rate year at the conclusion of this case.

Q. Please briefly describe the Company's need for additional natural gas rate relief.

A. Over 65% (or approximately $5.6 million) of the Company's need for additional rate relief relates to increases in total rate base, including changes in net plant investment (including return on investment, depreciation and taxes, offset by the tax benefit of interest), representing an increase of approximately $28 million in additional net rate base for the Oregon jurisdiction over the current authorized amount[1]. The remaining 35% (or approximately $3.0 million) of the Company's requested revenue requirement relates to an increase in operating and maintenance (O&M) and administrative and general (A&G) expenditures, and the net change in retail revenues since our last rate case filed in 2014.

Q. What are the major components of the changes to total rate base included in the Company's filing?

A. Oregon "gross" plant increased by approximately $33.3 million, or 10%, as compared to what is currently included in rates. These investments reflect, among other things, replacement and maintenance of Avista's utility system, and to sustain reliability, safety, and service to customers. Major projects included in this total include the East Medford Main Replacement and the Ladd Canyon Gate Station described by Ms. Schuh, as well as other required capital projects that have been or will be put in service through

[1] The authorized amounts for this analysis includes rate base authorized for rates that were effective April 16, 2015.

December 31, 2015, as well as capital investments in utility plant related to new customer hook ups for the 12 month period ended December 31, 2016. After adjusting for accumulated depreciation and amortization, and ADFIT, the net plant rate base increase is $25.4 million. After including return on investment, depreciation and taxes, offset by the tax benefit of interest, this amounts to approximately $5.6 million of the requested revenue requirement.

Also increasing the Company's net rate base, are working capital (excluding investment in materials and supplies that are included in the Company's authorized rate base) and the prepaid pension asset, net of accumulated deferred federal income taxes (ADFIT), of approximately $1 million and $5.7 million, respectively. These adjustments described further below, increased the Company's requested revenue requirement by approximately $124,000 (see Working Capital Adjustment) and $645,000 (see Prepaid Pension Investment Adjustment), respectively.

IV. GENERAL REVENUE REQUIREMENT

Q. Would you please explain what is shown in Exhibit No. 501?

A. Yes. Exhibit No. 501 shows 2014 actual base year results and 2016 test year natural gas operating results and rate base for the Company's Oregon jurisdiction. Column (a) of page 1 of Exhibit No. 501 shows the twelve months ended December 31, 2014 actual operating results and components of rate base; column (b) is the total of all adjustments to net operating income and rate base; and column (c) is the 2016 test year results of operations, all under existing rates. Column (d) shows the revenue increase necessary to allow the Company an opportunity to earn its requested 7.72% rate of return. Column (e) reflects 2016 test year natural gas operating results with the requested general increase of $8,557,000.

Q. Would you please explain page 2 of Exhibit No. 501?

A. Yes. Page 2 shows the calculation of the $8,557,000 revenue requirement using the requested 7.72% rate of return.

Q. Would you now please explain page 3 of Exhibit No. 501?

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, Oregon Commission fees, Oregon Energy Resource Supplier Assessment Fees, Franchise Taxes and Oregon Excise Tax, which is the Oregon state income tax. The Oregon state income tax rate that is used in the conversion factor is described later in my testimony when describing the adjustment for state income tax (SIT). Federal income taxes are reflected at 35%.

Q. Now turning to pages 4 through 11 of your Exhibit No. 501, would you please explain what those pages show?

A. Yes. Page 4 begins with actual operating results and rate base for the twelve months ended December 31, 2014 in column (1.00). Individual Historical 2014 Restating Adjustments start on page 4, column (1.01), and continue through page 5, column (1.06), resulting in the column labeled “Restated Historical 2014 AMA Base Year Total.” Individual 2016 test year Adjustments start on page 6, column (2.00), and continue through page 9, column (2.12), resulting in the column labeled “2016 AMA Test Year.” Finally, individual 2016 Test Year Restating Adjustments, representing previous Commission–ordered and/or standard components of our annual earnings reporting to the Commission, applied to the 2016 test year results, begin at page 10, column (3.00), and continue through page 11, column (3.03). The final column, which is a subtotal of all preceding columns of adjustments, results in the column labeled "Restated 2016 AMA Test Year." Exhibit No. 502 provides similar data as Exhibit No. 501, pages 1, and 4 through 11, at a detail level by FERC account. Descriptions of each adjustment noted above and included on pages 4 through 11 of Exhibit No. 501 are described more fully below, and supporting workpapers for each of these adjustments accompany the Company's filed case.

V. HISTORICAL RESTATING ADJUSTMENTS

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

A. Yes. The first adjustment, column (1.01) on page 4, **Allocation Factor Adjustment,** restates actual 2014 base year Oregon Results of Operations allocated expense accounts using updated allocation factors. During 2014, common costs to be allocated were allocated based on the allocation factors in effect as of January 1, 2014 through December 31, 2014. These factors were based on actual direct 2013 costs. The Company updates its allocation factors annually using the prior year's actual direct costs using the methodology approved by the Commissions. When the factors are updated annually, the factors are reviewed to identify any unusual trends or unexpected shifts in costs. Effective January 1, 2015, and utilized in this filing, are the most current allocations based on 2014 actual direct costs. For further discussion of the Company's allocation processes and methodologies, please see Section VIII. Cost Assignment and Allocation Procedures, below. This adjustment increases Oregon net operating income by $108,000.

Column (1.02), **Miscellaneous Restating,** restates actual 2014 base year results for miscellaneous restating items such as removal of non-utility related items, and reclassification of items to their appropriate service and jurisdiction. This adjustment increases Oregon net operating income by $3,000.

The adjustment in column (1.03), **Eliminate Adder Schedules**, removes both the revenues and expenses associated with all adder schedule rates except current gas costs and schedules 497 and 498[2]. The items eliminated include: Schedule 460 – Excess Franchise Tax, pass through of franchise taxes in excess of 3% charged only to customers in the various municipalities; Schedule 462 – Prior Gas Cost refund and amortization; Schedule 476 – Intervenor Funding surcharge and amortization; Schedule 478 – DSM surcharge and amortization; and Schedule 493 – LIRAP surcharge and amortization. This adjustment also identifies and consolidates all of the 2014 purchased gas cost related accounts into the "Gas Purchases" line item in order to simplify the 2016 test year revenue load adjustment. There is no revenue or expense impact of this portion of the adjustment, however, this process facilitates analysis of cost of service and rate design for base rates. Lastly, this adjustment eliminates the Collins deferral[3] (non-recurring) and the DSM Lost Margin[4] revenue recorded

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[2] The Schedule 497 Capital Project Cost Recovery adder was merged into base rates on 4/16/2015 and the Schedule 498 Klamath Falls Lateral adder was merged into base rates on 2/1/2014; therefore, it is appropriate to leave the associated 2014 revenues in the test year.

[3] In December 2013, Avista filed with the Commission under Schedule 447 a special contract with Collins Forest Products. The special contract provided for annual step rate increases between February 2014 and January 2016 in an effort to move the customer from a negotiated rate to tariffed rates on Schedule 456. The increase in revenue resulting from the contract was negotiated during the pendency of Avista's 2013 general rate case (Docket No. UG-246), but was not included in the final agreed-upon settlement revenue requirement which was later approved by the Commission. Therefore, Avista and Commission Staff agreed that 90% of the net revenue increase from the revised special contract would be deferred and returned to customers through the PGA until such time as Avista's revenues were reset in a later general rate case (completed in Docket No. UG-284).

[4] Deferral of lost margin revenue was originally authorized in Order No. 93-1881 in Docket UM 636 and subsequently reauthorized on June 10, 2014 by Order No. 14-206 in Docket Um 1165(10). The 2014 test year included one month of DSM lost margin revenue before the base was re-set with rates effective 2/1/2014. Pro forma revenue reflects 2016 expected revenues which incorporate the effect of any reduction in usage associated with expected demand side management measures.

in 2014 in order to properly reset the lost margin base with implementation of new rates. The total adjustment decreases net operating income by $10,000.

Starting on page 5, the adjustment in column (1.04), **Weather Normalization Sales/Purchases**, normalizes weather sensitive gas therm sales by eliminating the effect of temperature deviations above or below historical normals. This adjustment restates revenue and gas cost to reflect the change in therm sales if weather had been normal based upon energy rates and the authorized weighted average cost of gas in effect during the year. In compliance with the Settlement agreed to in Docket No. UG-246 (Order No. 14-015) the Company has utilized weather sensitivity factors and other parameters that are consistent with the Company's most recently acknowledged Integrated Resource Plan. Going forward, the Company plans on continuing to use the most recently acknowledged IRP weather parameters for the Commission Basis weather normalization adjustment to maintain consistency in all Oregon regulatory filings as agreed to in the UG-246 settlement. The impact of the weather normalization adjustment is an increase to Oregon net operating income of $2,204,000.

The adjustment in column (1.05), entitled **Restate Debt Interest**, restates debt interest using the Company's 2016 test year weighted average cost of debt, as outlined in the testimony and exhibits of Company witness Mr. Thies. This adjustment restates debt interest on the Results of Operations level of rate base shown in column (1.00) only, resulting in a revised level of tax deductible interest expense on actual 2014 base year rate base. The federal income tax effect of the restated level of interest for the historical base year reduces Oregon net operating income by $60,000.

The Federal income tax effect of the restated level of interest on all other rate base adjustments included in the Company's filing are included and shown as an income impact in each individual rate base adjustment described later in this testimony.

The adjustment in column (1.06), **Materials & Supplies Investment**, adjusts Oregon's share of the Company's 2014 AMA investment in materials and supplies inventory. In Docket No. UG-246, the Parties to the case agreed that this investment should be included in rate base, so Oregon's share of this investment is included in its monthly Results of Operations report. This adjustment restates the balance included in Results of Operations for updated allocation factors in this case. This adjustment decreases Oregon net operating income by $1,000 and decreases rate base by $46,000.

Q. Before describing the final column on page 5 of Exhibit No. 501, are there any other regulatory asset balances included in the Company's restated 2014 base year?

A. Yes. Other regulatory assets included in the Company's 2014 base year, and shown on page 4 of Exhibit No. 501, Column (1.00) titled "Per Results of Operations Report," line 252 titled "Total Gas Inventory," is Oregon's share of the Company's Jackson Prairie Storage natural gas inventory balance of $5.275 million. Company witness Ms. Morehouse describes in more detail Avista's ownership and use of this facility.

Oregon's share of the Jackson Prairie inventory balance is recorded in FERC Account Nos. 117 and 164.[5]/[6]

Q. Please continue with your description of the final column on page 5 of Exhibit No. 501.

A. The final column entitled Restated Historical 2014 AMA Base Year Total,

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[5] Inventory has been excluded from the Company's working capital adjustment calculation described later in my testimony, because separate rate base treatment has been the consistent historical approach approved for the Jackson Prairie inventory balance.

[6] Rate base treatment of natural gas inventory is consistently applied within Avista's Idaho and Washington natural gas jurisdictions, as well as by its peer utilities serving customers in the State of Oregon.

provides a subtotal of the preceding columns (1.00) through column (1.06) and represents actual operating results and rate base, plus the restating adjustments that have been previously discussed.

VI. 2016 TEST YEAR ADJUSTMENTS

Q. Please explain the significance of the twelve columns that begin on page 6 and continue through page 9, in your Exhibit No. 501.

A. The thirteen adjustments, subsequent to the Restated Historical 2014 AMA Base Year Total column, represent adjustments that recognize the jurisdictional impacts of items that will impact the 2016 test year operating results. They encompass revenue and expense items as well as additional capital projects and rate base items. These adjustments bring the 2014 base year operating results and rate base to the appropriate level for the 2016 AMA test year.

Q. Please explain the first adjustment on page 6.

A. Column (2.00), **2016 Test Year Expense Adjustment**, reflects increases in non-labor O&M and A&G expenses through 2016 for various FERC accounts. Workpapers accompanying my testimony and exhibits in this case provide the adjustments by FERC account, provide the Company's analysis of each adjusted FERC account amount and show the use of a CPI of .08% year over year for 2015 and 2016. This adjustment decreases Oregon net operating income by $96,000.

Column (2.01), **2016 Test Year Revenue Load Adjustment**, takes into account normalized usage and customers during 2016. Revenues and purchased gas expense are calculated based on the April 16, 2015 approved rates, which include associated gas costs approved in the Company's most recent Purchased Gas Adjustment effective November 1, 2014. This adjustment was made under the direction of Mr. Ehrbar and is described further in his testimony. The effect of this adjustment is to increase Oregon net operating income by $4,099,000.

Q. Please continue with your explanation of the adjustments on page 7.

A. Column (2.02), **2016 Test Year Labor and Benefits Adjustment**, adjusts the 2014 base year labor and benefits to reflect the 2016 level of expense. This adjustment includes three separate calculations including the following 1) Non-Executive Labor (Union and Non-Union), 2) Executive Labor and 3) Pension and Medical Benefits.

Q. Please describe the Non-Executive Labor calculation included in the 2016 Test Year Labor and Benefits Adjustment.

A. The Non-Executive Labor portion of the adjustment reflects changes to the 2014 base year for union and non-union wages and salaries. For <u>non-union</u> employees, base year wages and salaries are restated to annualize the March 2014 overall actual increase of 3.0%, the March 2015 overall increase of 3.0%, and 10 months of the planned March 2016 increase of 3.0%. An increase for 2016 will be presented to the Compensation Committee of the Board of Directors for approval at the Board's May 2015 meeting. This amount will be updated based on market data in November 2015 to be effective in March 2016. For <u>union</u> employees, adjustments were made to the 2014 base year wages and salaries in accordance with contract terms. The current contract between the Company and Local Union No. 659 is in effect from April 1, 2014 through March 31, 2017. The terms of the contract call for 3% wage and salary increases effective April 1st for 2014, 2015 and 2016. Accordingly, base year wages and salaries are restated to annualize the April 2014 increase, the April 2015 increase and nine months of the 2016 increase. The effect of the Non-Executive Labor portion of this adjustment on Oregon's net operating income is a decrease of $236,000.

Q. Please continue with a description of the Executive Labor calculation included in the 2016 Test Year Labor and Benefits Adjustment.

A. The Executive labor calculation reflects the current 2015 executive officer salaries. However, the Company has included updated utility and non-utility allocation percentages planned for 2016. The net result of these changes increases the executive compensation expense approximately $25,000 from that included in the Company's historical base year. No additional increases in executive labor for 2015 or 2016 have been included in this filing.

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

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

Q. Please describe the third calculation included in the 2016 Test Year Labor and Benefits Adjustment.

A. The third portion of the calculation included in the Labor and Benefits adjustment is the pension and medical expense adjustment. This calculation adjusts the 2014 base year pension and medical expense to include the net changes in the Company's pension and medical insurance expense expected for 2016. These changes reflect an increase in pension costs of approximately $9 million at a system level from the 2014 base year to the 2016 test year, and an increase of approximately $3.7 million at a system level in medical insurance costs for the same year. The decrease to net operating income associated with pension and medical insurance cost changes is approximately $368,000.

Q. Please describe the pension expense included in the pension and medical expense calculation above and Oregon's share of this expense.

A. The Company's pension expense portion of the calculation above is determined in accordance with Accounting Standard Codification 715 (ASC-715), and has increased on a system basis from approximately $19.5 million for the actual base year costs for the twelve months ended December 31, 2014, to $28.7 million for 2016. The increase in pension expense ($437,243 Oregon) is primarily due to updated mortality tables, the discount rate on pension liability and expected return on assets.

The pension cost included in this case is based on an estimate as of September 22, 2014 as determined in accordance with ASC-715 by an independent actuarial firm, Towers Watson. New estimates will be available in May 2015 at which point the Company will update the pension and post-retirement estimates provided in the pro-forma cross check. These calculations and assumptions are reviewed by the Company's outside accounting firm annually for reasonableness and comparability to other companies.

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

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

Q. Please now describe the medical insurance and post-retirement expense portion of the adjustment and Oregon's share of this expense.

A. The Company's medical insurance and post-retirement <u>expense</u> portion of this adjustment ($178,704 Oregon) adjusts for the estimated medical-related costs for 2016 above the 2014 base year. This adjustment includes costs associated with the employee and retiree medical plans and the FAS106 expense, which records the costs associated with post retirement medical. Net medical insurance and post-retirement expense has increased on a system basis from $27.5 million for the 2014 base year to $31.2 million for 2016. The increase in 2016 represents medical trend and utilization expectations, as well as accounting for Health Care Reform mandates.

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

A. In October 2013 the Company revised its health care benefit plan. For non-union employees hired or rehired on or after January 1, 2014. Upon retirement the Company no longer provide a contribution towards his or her medical premiums. The Company will provide access to the retiree medical plan, but the non-union employees hired or rehired on or after January 1, 2014, will pay the full cost of premiums upon retirement. In addition, beginning January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees will be revised. The revision will result in separate health insurance premiums for each group.

Column (2.03), **Prepaid Pension Investment Adjustment,** increases regulatory assets by $5,655,000 related to Oregon's share of the Company's prepaid pension asset, net of Accumulated Deferred Federal Income Tax (ADFIT), computed on an AMA 2014 base year basis.

Q. Has the Company previously requested to include in rate base its prepaid pension asset in its Oregon jurisdiction?

A. Yes. The Company previously requested to include in rate base its prepaid pension asset in Docket No. UG-284, however, that was removed by the settling Parties due, in part, to the timing of that case and the unsettled issues in Docket No. UM 1633, as discussed below. The Company has previously requested recovery of Oregon's share of its pension cost planned during the upcoming rate year, based on its Actuarial derived Financial Accounting Standard (FAS) 87 expense amount. However, in November 2012, the Oregon

Commission opened an investigation into the treatment of pension costs in utility rates. Through this open docket, Docket No. UM 1633, the question of how pension costs should be recovered, whether there should be a return on a prepaid pension asset, and how that prepaid pension asset balance will be valued, is being investigated.

For Avista, a prepaid pension asset exists on its books today, resulting from cumulative contributions in excess of cumulative FAS 87 expense, resulting in additional financing costs to the Company. This condition is expected to reverse in the future, with pension expense exceeding contributions and reducing the prepaid balance eventually to zero. However, until these excess contributions are fully recovered, the Company is incurring and will continue to incur costs to finance its prepaid pension asset. Therefore, the Company believes it is appropriate to include in rate base this asset, and be allowed to earn a return on such asset. To exclude a return on the excess cash contributions in rates excludes a portion of costs attributable to providing services to its customers.

Column (2.04), **2016 Test Year Property Tax Adjustment**, restates the 2014 base year accrued levels of property taxes to the 2016 test year level using the most current information. The 2014 base year accrued levels of property taxes included in the Company's 2014 Oregon operating results reflect property taxes accrued based on plant balances as of December 31, 2013. This adjustment estimates the taxes to be paid on plant balances as of December 31, 2014 during 2016. The adjustment is calculated by using the last known value assessments and levy rates, adding plant additions through December 31, 2014, less depreciation, and then applying a small escalator to the levy rates to reflect their general increasing trend. The effect of this adjustment is to decrease Oregon net operating income by $83,000.

Column (2.05), **2014 EOP Capital Adjustment**, adjusts the 2014 base year rate base (including the associated accumulated depreciation and ADFIT) stated on an AMA basis to an end-of-period (EOP) basis, including the effect of using updated allocation factors for allocated common plant and associated accumulated depreciation and ADFIT. This portion of the adjustment increases rate base by $540,000. Also included in this adjustment is an adjustment to reflect the correction of the ADFIT balance within the general ledger. This portion of the adjustment increases rate base by $6,134,000. This adjustment was made under the direction of Ms. Schuh and is described further in her testimony. The impact on Oregon net operating income for this adjustment is an increase of $74,000, with an increase to rate base of $6,674,000.

Q. Please now turn to page 8 and continue with your explanation of the 2016 test year adjustments.

A. Column (2.06), **2015 EOP Capital Adjustment**, reflects all 2015 capital additions together with the associated accumulated depreciation and ADFIT at a 2015 EOP basis. This adjustment also includes the annual level of associated depreciation expense on the 2015 capital additions. In addition, this adjustment adjusts the plant in service at December 31, 2014 [included in adjustment (2.05)] together with the associated accumulated depreciation and ADFIT to a December 31, 2015 EOP basis. This adjustment also reflects the full year of associated depreciation expense on all plant-in-service at December 31, 2014, using the depreciation rates approved in Oregon Commission Order 13-168, dated May 6, 2013 (Docket No. UM 1626). Those depreciation rates on Oregon direct plant were effective July 1, 2014, as approved in the Company's last general rate case. This adjustment was made under the direction of Ms. Schuh and is described further in her testimony. The impact on

Oregon net operating income for this adjustment is a decrease of $1,505,000, with an increase to rate base of $32,986,000.

Column (2.07), **2016 AMA Capital Adjustment**, reflects 2016 capital additions related to new customer hookups in 2016 together with the associated accumulated depreciation and ADFIT on a December 31, 2016 AMA basis. This adjustment also includes the AMA level of associated depreciation expense on these 2016 capital additions. This adjustment was made under the direction of Ms. Schuh and is described further in her testimony. The impact on Oregon net operating income for this adjustment is a decrease of $9,000, with an increase to rate base of $2,003,000.

Column (2.08), entitled **Working Capital**, increases total rate base for the Company's working capital adjustment. Working capital involves the lag in time between the collection of revenues for services rendered and the necessary outlay of cash by the Company to pay the expenses of providing those services. Working capital represents investor supplied funds that are properly included in the Company's rate base for ratemaking purposes.

While there are various methods used to determine a Company's working capital, the Company has calculated its working capital in this proceeding using the Investor Supplied Working Capital (ISWC) method. The Company believes this is a reasonable approach to computing working capital, representing expended funds to provide reliable service to its customers. The net effect of this adjustment increases Oregon net operating income by $12,000 and increases rate base by $1,090,000.

Column (2.09), entitled **2016 Test Year Insurance**, adjusts 2014 base year insurance expense for general liability, directors and officers ("D&O") liability, and property to reflect the expected 2016 insurance level of expense, resulting in an increase in expense of $37,000

Oregon share. The net effect of this adjustment decreases Oregon net operating income by $22,000.

Q. Please now turn to page 9 and continue with your explanation of the 2016 test year adjustments.

A. Column (2.10), entitled **2016 Test Year IS/IT Expense,** includes the incremental costs associated with Information Services and Information Technology, including software development, application licenses, maintenance fees, and technical support for a range of information services programs. These incremental expenditures are necessary to support Company cyber and general security, emergency operations readiness, natural gas facilities and operations support, customer services and the new CIS system that was implemented in early 2015. The effect of this adjustment decreases net operating income by $157,000.

Column (2.11) **2016 Test Year Atmospheric Testing**, adjusts the historical base year expense for atmospheric corrosion expense. This is an inspection program to detect 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 includes the inspection costs and follow-up remedial actions based on transitioning the Atmospheric Corrosion (AC) inspection cycle from a three-year rotation between the Company's jurisdictions (Washington, Idaho, and Oregon) to an inspection cycle that will be completed one third of each jurisdiction per year.

The atmospheric testing expense included in the twelve-month base year ending December 31, 2014, was approximately $360,000. For 2016, the atmospheric testing inspection program will include costs of approximately $428,000 for the AC inspection cycle and approximately $95,000 for the remediation costs, for a total of $523,000. The net increase to expense is therefore $163,000, decreasing Oregon net operating income by $97,000.

Column (2.12), **Incentive Pay Adjustment**, adjusts actual incentives included in the Company's 2014 base year ending to reflect a six-year average of payout percentages, reducing overall Oregon expense by approximately $0.2 million. For officers, the incentive amount included in the Company's filing is based on the 2015 incentives to be accrued for officers (paid Q-1 of 2016), based on O&M targets.[7] This amount was then multiplied by the six-year average of actual percentage payouts for the years 2009-2014 (or 40.23%). For non-officer incentives, this is calculated by using the 2016 level of labor expense (determined in adjustment 3.03 Restate Labor) multiplied by the payout incentive opportunity per the Company's current incentive plan (or 12% overall) to determine the incentive payout opportunity, multiplied by the six-year average of actual percentage payouts for the years 2009-2014 (or 102.16%). The net effect of this adjustment increases Oregon net operating income by $122,000.

Q. Please briefly describe the Executive STIP.

A. The STIP is designed to align the interests of executives with both customer and shareholder interests in order to achieve overall positive operating and financial performance for the Company. The STIP is a pay-at-risk plan whereby employees are eligible to receive cash incentive pay if the stated targets are achieved.

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

The STIP has four operational components, plus two earnings per share (EPS) components. The total amount associated with utility operational components is 40% and is broken down as follows: 20% O&M Cost-Per-Customer, 8% Customer Satisfaction, 8% Reliability, and 4% Response Time. The EPS components account for 60% of the total opportunity and are broken out into 50% utility EPS and 10% non-utility EPS. Only the operational components (40%) are proposed to be included in retail rates. Customers benefit from these metrics that are designed to drive cost-control, and delivery of safe, reliable service with a high level of customer satisfaction. The remaining 60% related to EPS targets is borne by shareholders.

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

A. Employee compensation is a combination of base pay and pay-at-risk/variable performance based via the Short Term Incentive Plan (STIP). The STIP provides for a portion of compensation to be at risk contingent upon the achievement of specific goals for performance, which are likely to produce long term customer benefits. This tension in plan design helps incent and focus all employees on the stated goals of the Company. In order to achieve this pay-at-risk compensation, employees have to keep focused on cost control, customer satisfaction and reliability within the system. These metrics are designed to be reasonably achievable with strong management performance. Maximum performance levels are designed to be difficult to achieve given historical performance and forecasted results at the time the metrics are approved. The pay-at-risk component of compensation is not designed to pay out the full incentive opportunity every year, nor is it designed to have no payout for an extended period of time. Pay-at-risk plans are designed to help focus employees on stated goals that benefit the Company and its customers, while at the same time functioning as an integrated component of total compensation.

In accordance with the Company's overall compensation design to align elements of incentive plans among all Company employees and executives, the non-executive Employee Incentive Plan (Plan) has essentially the same stated goals as the STIP discussed above. Both plans provide incentives and focus employees on stated goals while recognizing and rewarding employees for their contributions toward achieving those goals. The components of the non-executive employee incentive plan are as follows: 60% O & M Cost-Per-Customer, 15% Customer Satisfaction, 15% Reliability Index and 10% Response Time.

Q. What portion of the Short Term Incentive Plans have been included in this case?

A. The Company has included 100% of the non-executive STIP and 40% of the executive officer STIP (excluding those metrics related to EPS targets) in this case. Because all metrics in the non-officer STIP and 40% of the Officer STIP are customer-focused and benefit ratepayers, it is appropriate to include the customer focused STIP incentives in general rates. The 2014 base year already excludes the portion of officer STIP related to EPS targets. In addition, because incentive loaders follow where base salary labor dollars are charged, a portion of non-officer incentives are also already charged to non-utility accounts for those employees performing work not related to the utility. Therefore, the appropriate portion of incentives related to non-utility is reflected on the Company's general ledger for both executive and non-executive STIPs.

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

A. The Executive Officer Long Term Incentive Plan (LTIP) is comprised of two components, which serve two different purposes[8]. Performance Shares account for 75% of the plan with metrics related to Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). The purpose for this portion of the plan is to provide a direct link to the long-term interests of shareholders by assuring that performance shares will be paid only if the Company attains specified financial performance levels. This portion of the plan was modified in 2014 to include both Cumulative Earnings-Per-Share (CEPS) and Total Shareholder Return (TSR). In previous years, vesting of performance-based equity awards were 100% contingent on the Company's Total Shareholder Return (TSR) relative to our peer group over a three-year period. Under the new design, two-thirds of the awards are contingent on TSR relative to our peers and one-third is measured by our CEPS over a three-year period. The Company has excluded the Performance Share portion of the LTIP from the retail ratemaking because it is tied to shareholder performance.

Restricted Stock Unit (RSU) awards account for 25% of the LTIP and vest based on continued service. The purpose for this portion of the plan is to provide an incentive for employees to remain employed by the Company. The long-term nature of large-scale utility projects spanning multiple years are completed more efficiently with experienced, consistent leadership. In addition, it is the Company's policy to promote from within when possible, preserving the values inherent in our culture that drive customer satisfaction, reliability of service, etc. Employees with a long tenure of employment with the Company are well versed in the Company's culture and will continue to cultivate the values embedded within Avista.

[8] As with all components of the executive officer compensation, the Compensation Committee determines all material aspects of the long-term incentive reward – who receives the award, the amount of the award, the timing of the award, as well as any other aspects of the award that may be deemed material.

The Restricted Stock Unit portion of the plan is included in retail ratemaking because customers benefit from long-term leadership with a vested interest in the efficient operation of the Company and high customer satisfaction[9].

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

A. The LTIP costs included in retail rates in the filing are related to the Restricted Stock Units, in the amount of $93,000 Oregon's share based on 2014 actuals, of $1.0M on a system basis.

The final column entitled **2016 Test Year AMA Total**, provides a subtotal of the preceding columns (1.00) through column (2.12) and represents 2016 Test Year operating results and rate base prior to any required restating adjustments described below.

VII. RESTATING 2016 TEST YEAR ADJUSTMENTS

Q. Please explain the significance of the columns that begin on page 10 and continue on page 11, in your Exhibit No. 501.

A. The four adjustments subsequent to the "2016 AMA Test Year" column represent restating adjustments to adjust the 2016 total results for Commission required adjustments. They encompass restating of expense items for the 2016 test year as well as rate base items. These adjustments bring the 2016 test year operating results and rate base to the 2016 restated test year results.

Starting on page 10, the first adjustment in column (3.00), **Uncollectible Expense Adjustment**, revises the 2014 base year level of accrued expense included within the Company's Results of Operations, to the historical three-year average of actual net write-offs.

[9] Total CEO Long Term Incentive Plan has been excluded because both the restricted stock and performance shares have financial performance-related triggers.

The effect on Oregon net operating income is an increase of $155,000.

Column (3.01), **Memberships and Dues Adjustment**, classifies expenses by category and specific percentages are applied to determine the recoverable amounts. This calculation is consistent with the method utilized in recent general rate cases. The effect of this adjustment on Oregon net operating income is an increase of $22,000.

Q. Please now turn to page 11 and continue with your explanation of the restating 2016 test year adjustments.

A. Column (3.02) **State Income Tax (SIT) Adjustment**, **State Income Tax (SIT) Adjustment**, adjusts Oregon SIT expense applicable to Oregon natural gas utility operations for the 2016 test year. State income tax expense was determined for Oregon natural gas utility operations using the apportionment method, which is consistent with the method used in Avista's most recent filed general rate case in Oregon (Docket No. UG-284). This method determined Oregon's taxable income using an apportionment factor for Oregon that was applied to the total Company taxable income[10]. Oregon's state tax rate was then applied to the computed Oregon's taxable income to derive the state income tax. All of the available tax credits in Oregon, including BETC, were applied to the computed state income tax to determine the level of state income tax that the Company will pay to Oregon in the rate year.

The Company paid no Oregon state income taxes in the 2014 historical base year. In 2014, the Company had two large tax deductions[11] to reduce taxable income to a net taxable

[10] Avista Corporation files a consolidated federal income tax return that includes electric utility operations in Washington and Idaho, natural gas utility operations in Oregon, Washington, and Idaho, and non-utility subsidiary operations.

[11] The deductions include a cumulative method change adjustment related to its capitalized repairs deduction for years prior to 2014 and bonus depreciation for 2014.

loss. These tax deductions are currently not available in 2016. In addition, all of the available Company's tax credits will be used in 2015 which results in no tax credits available in 2016. Therefore, the Oregon SIT expense in 2016 will be significantly greater than the expense in 2014. The adjustment to state income taxes decreases Oregon's net operating income by $731,000.

The Company used the same apportionment method to determine the SIT rate that is used in the derivation of the net operating income to gross revenue conversion factor as shown on page 3 of Exhibit No. 501.

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

A. The Company used 8.0% for the apportionment tax rate in this case. The calculation of this rate is described below.

Oregon's taxable income is determined by applying the apportionment factor of 10.78% to system taxable income. The tax is then computed by applying the Oregon tax rate, which is 7.60% for 2014, to the calculated Oregon taxable income. This amount is the tax that is paid to the State of Oregon. Avista records 75% of total Oregon tax to the Oregon natural gas operations and 25% to the electric operations, for the share of tax that is for an electric generating plant located in Oregon.

The "apportionment tax rate" for computing Oregon state income taxes for its natural gas operations is shown below in Table No. 1.

Table No. 1:

Calculation of Avista's Apportionment Tax Rate						
Oregon's Apportionment Rate	X	Oregon's Tax Rate	X	Natural Gas Portion of Oregon Operations	=	Oregon's Apportionment Tax Rate
10.78%	X	7.60%	X	75%	=	0.614%

By using the three components of the actual tax calculation for the Oregon natural gas operations, an Oregon apportionment tax rate is 0.614%, which is then applied to system taxable income. This rate can only be used if it is applied to Avista Utilities' total system revenues, system expenses and system taxable income. When Avista prepares a general rate case revenue requirement, the starting point is the actual Results of Operations for its Oregon natural gas operations. Use of this rate in a general rate case, which is calculated based on Avista's total utility system in Washington, Idaho and Oregon, would understate SIT. In this filing, the Company used an Oregon apportionment tax rate of 8.0%, which produces the appropriate level of expense when applying it to Oregon's taxable income.

The 8.0% tax rate was determined by "grossing up" the 0.614% apportionment rate for system taxable net income by Oregon's share of system revenues. Oregon's revenues from its natural gas operations represent approximately 7.68% of total revenues. Therefore, 0.614% divided by 7.68% equals 8.0%, which is the Oregon apportionment tax rate used in this filing.

Q. Please now continue with your explanation of the restating 2016 test year adjustments on page 11.

A. Column (3.03), **Restated Salaries and Wages**, adjusts the 2016 labor expense to be consistent with the method agreed to by the parties in the rate proceeding Docket No.

UG-186. This method utilized Staff's approach that adjusts for 1/2 the difference between the 2016 level of payroll costs and the annual percent based on the Consumer Price Index for non-union employees from 2013 to 2016. The Union portion of this adjustment annualizes the effect on union labor expense using the union wage adjustments implemented in April of each year. The Company has applied this approach to its 2016 salary expense. The result of this adjustment on net operating income is an increase of $56,000, and a decrease in rate base of $52,000.

Q. Referring back to page 1, line 47, of Exhibit No. 501, what are natural gas rates of return realized by the Company in Oregon during the 2014 historical test year and the 2016 test year?

A. For the State of Oregon, the actual 2014 historical base year rate of return was 4.91%. The restated 2016 test year rate of return is 5.39% under present rates, which is below the 7.72% rate of return requested by the Company in this case.

Q. How much additional net operating income is required for the State of Oregon gas operations to allow the Company an opportunity to earn its proposed 7.72% rate of return?

A. The net operating income deficiency amounts to $4,959,000, as shown on line 5, page 2 of Exhibit No. 501. The resulting revenue requirement is shown on line 7 and amounts to $8,557,000 or a revenue increase of 16.1% and a bill increase of 8.0%.

VIII. COST ASSIGNMENT AND ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional allocation procedures since the Company's last general natural gas case, Docket No.

UG-284?

A. No. For ratemaking purposes, the Company directly assigns or allocates revenues, expenses and rate base between electric and gas services and between Oregon, Washington, and Idaho jurisdictions where electric and/or gas service is provided. The current methodology is based on a previously-approved methodology that has been in place for several years. The allocation factors used in this case are included in my workpapers.

Q. Do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. When the Company designed the allocation methodology that is being used today, the specific objectives identified were as follows:

a) The method must be acceptable to all regulators to prevent any stranded costs or investment,
b) The number of cost allocation methods should be minimized,
c) The method needs to be simple,
d) The method needs to have a sound, rational basis,
e) Allocations under the method should be automated, and
f) The method needs to produce reasonable results.

These objectives are still relevant today. The Company believes the methodology continues to meet these overall objectives. The method proposed by Avista and approved by the three Commissions (Oregon, Washington, and Idaho) produces a reasonable allocation of common costs.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

JENNIFER S. SMITH
Exhibit No. 501

Revenue Requirement and Allocations

AVISTA UTILITIES
OREGON JURISDICTION
NATURAL GAS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No.	Description	PRESENT RATES Per Results of Operations Report	PRESENT RATES Total Adjustments	PRESENT RATES Restated 2016 AMA Test Year	WITH PROPOSED RATES Proposed Revenues & Related Exp	WITH PROPOSED RATES Proposed Total (AMA)
		a	*b*	*c*	*d*	*e*
1	OPERATING REVENUES					
2	Total General Business	$82,303	($32,639)	$49,664	$8,557	$58,221
3	Total Transportation	3,191	369	3,560	0	3,560
4	Other Revenues	115,595	(115,428)	167	0	167
5	Total Operating Revenues	201,089	(147,698)	53,391	8,557	61,948
6						
7	OPERATING EXPENSES					
8	Gas Purchased	161,753	(161,753)	0	0	0
9	Operation and Maintenance	5,672	6,882	12,554	0	12,554
12	Uncollectible Accounts	732	(432)	300	47	347
11	Administration & General	8,090	535	8,625	0	8,625
10	OPUC Commission Fees	582	(399)	183	29	212
13	Total Operation & Maintenance	176,829	(155,167)	21,662	76	21,738
14						
15	DEPRECIATION, AMORTIZATION, TAXES					
16						
17	Municipal Occupation & License Tax	1,489	(1,489)	0	0	0
17	Franchise Fees - Conversion Factor	1,851	(677)	1,174	188	1,362
18	R&P Property Tax	2,402	139	2,541	0	2,541
19	State Income Tax	0	0	0	0	0
20	Depreciation & Amortization	7,836	3,183	11,019	0	11,019
21	Total Operating Expenses	190,407	(154,011)	36,396	264	36,660
22						
23	OPERATING INCOME BEFORE FIT/SIT	10,682	6,313	16,995	8,293	25,288
24						
25	INCOME TAXES					
26	Current Federal Income Taxes	(8,507)	1,639	(6,868)	2,671	(4,197)
27	Debt Interest	0	(478)	(478)	0	(478)
28	Deferred Federal Income Taxes	11,277	(7)	11,270	0	11,270
29	State Income Taxes	(416)	1,629	1,213	663	1,876
30	Total Income Taxes	2,354	2,784	5,138	3,334	8,471
31						
32	NET OPERATING INCOME	$8,328	$3,529	$11,857	$4,960	$16,817
33						
34						
35	RATE BASE					
36	Utility Plant in Service	$312,767	$55,648	$368,415	$0	$368,415
37	Accumulated Depreciation and Amortization	(102,015)	(8,322)	(110,337)	0	(110,337)
38	Accumulated Deferred FIT	(46,513)	(5,715)	(52,228)	0	(52,228)
39	Net Utility Plant	164,239	41,611	205,850	0	205,850
40						
41	Inventory	3,078	0	3,078	0	3,078
42	Working Capital	2,197	1,044	3,241	0	3,241
43	Prepaid Pension, Net of ADFIT (1)	0	5,655	5,655	0	5,655
44						
45	TOTAL RATE BASE	$169,514	$48,310	$217,824	$0	$217,824
46						
47	RATE OF RETURN	4.91%		5.44%		7.72%

(1) Prepaid Pension Asset of $8.0 million is offset by $2.3 million Accumulated Deferred Federal Income Tax (ADFIT), resulting in a net Prepaid Pension rate base amount of $5.7 million.

AVISTA UTILITIES
OREGON NATURAL GAS
CALCULATION OF REVENUE REQUIREMENT
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No.	Description	(000's of Dollars)
1	Forecasted Rate Base	$217,824
2	Proposed Rate of Return	7.72%
3	Net Operating Income Requirement	$16,816
4	Forecasted Net Operating Income	$11,857
5	Net Operating Income Deficiency	$4,959
6	Conversion Factor	0.57951
7	Revenue Requirement	$8,557
8	Total Distribution Revenues	$53,224
9	Percentage Revenue Increase	16.1%
10	Total Present Billed Revenue	$106,713
11	Percentage Billed Increase	8.0%

AVISTA PROPOSED COST OF CAPITAL

	Capital	Cost	Weighted
Long Term Debt	50.000%	5.53%	2.770%
Common Equity	50.000%	9.90%	4.950%
Total	100.00%		7.72%

AVISTA UTILITIES
OREGON NATURAL GAS
CONVERSION FACTOR EXHIBIT
TWELVE MONTH BASE YEAR ENDED DECEMBER 31, 2014

Line No.	Description		Factor	Amounts
1	Revenues		1.000000	8,557
2	Expenses:			
3	Uncollectibles		0.005496	47
4	Commission Fees		0.002500	21
5	Energy Resource Supplier Assessment		0.000923	8
6	Franchise Fees		0.021987	188
7	Oregon Excise Tax		0.077535	663
8	Total Expense		0.108441	927
9	Net Operating Income Before FIT		0.891559	7,630
10	Federal Income Tax @	35.00%	0.312046	2,671
11	REVENUE CONVERSION FACTOR		0.5795127	4,959

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED HISTORICAL 2014 AMA BASE YEAR
TWELVE MONTH BASE YEAR ENDED DECEMBER 31, 2014

Line No. (1)	Description		Per Results of Operations Report	Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment
	Adjustment Number		1.00	1.01	1.02	1.03
	Workpaper Reference		G-ROO	G-AF	G-MR	G-EAS
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		82,303	0	0	1,337
12	TRANSPORTATION REVENUES		3,191	0	0	(45)
19	OTHER OPERATING REVENUES		115,595	0	0	(115,428)
21	**TOTAL GAS REVENUES**		**201,089**	**0**	**0**	**(114,136)**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		161,753	0	0	(118,681)
37	TOTAL OTHER GAS SUPPLY EXPENSE		(6,933)	(5)	0	7,440
39	**TOTAL PRODUCTION EXPENSES**		**154,820**	**(5)**	**0**	**(111,241)**
40						
45	TOTAL UG STORAGE OPER EXP		134	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		114	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		64	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**312**	**0**	**0**	**0**
56						
79	DISTRIBUTION O&M EXPENSES		7,672	(11)	(1)	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		4,954	0	0	0
88	TOTAL DISTRIBUTION NON-FIT TAXES		5,678	0	0	(1,428)
92	**TOTAL DISTRIBUTION EXPENSES**		**18,304**	**(11)**	**(1)**	**(1,428)**
93						
101	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,475**	**(10)**	**0**	**15**
107	**CUSTOMER SVC & INFO OPERATING EXP**		**2,056**	**0**	**(1)**	**(1,475)**
113	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
114						
129	ADMIN & GENERAL OPERATING EXP		8,672	(143)	(3)	10
132	TOTAL A&G DEPRCIATION EXP		1,575	0	0	0
137	TOTAL A&G AMRT/NON-FIT TAXES		1,194	0	0	0
139	TOTAL A&G DEPR/AMRT/NON-FIT TAXES		2,769	0	0	0
140						
141	**TOTAL ADMIN & GENERAL EXPENSES**		**11,441**	**(143)**	**(3)**	**10**
142						
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**(1)**	**0**	**0**	**0**
150						
151	**TOTAL EXPENSES BEFORE FIT**		**190,407**	**(169)**	**(5)**	**(114,120)**
152						
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**10,682**	**169**	**5**	**(16)**
154						
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	(8,507)	54	2	(5)
156	DEBT INTEREST	2.858%	0	0	0	0
157	DEFERRED INCOME TAX		11,277	(7)	0	0
158	STATE INCOME TAXES	8.00%	(416)	14	0	(1)
159	**GAS NET OPERATING INCOME (LOSS)**		**8,328**	**108**	**3**	**(10)**
160						
161	**RATE BASE**					
162	**PLANT IN SERVICE**					
167	TOTAL INTANGIBLE PLANT		7,234	0	0	0
183	TOTAL UNDERGROUND STORAGE PLANT		5,863	0	0	0
189	TOTAL PRODUCTION PLANT		8	0	0	0
203	TOTAL DISTRIBUTION PLANT		273,959	0	0	0
217	TOTAL GAS GENERAL PLANT		25,703	0	0	0
219	**GROSS PLANT IN SERVICE**		**312,767**	**0**	**0**	**0**
220						
225	TOTAL ACCUMULATED DEPRECIATION		(99,090)	0	0	0
226						
231	TOTAL ACCUMULATED AMORTIZATION		(2,925)	0	0	0
233	**TOTAL ACCUMULATED DEPR/AMORT**		**(102,015)**	**0**	**0**	**0**
234						
235	NET GAS UTILITY PLANT before ADFIT		210,752	0	0	0
236						
237	ACCUMULATED DFIT					
238	ADFIT - Gas Plant in Service		(39,461)	0	0	0
239	ADFIT - Common Plant (282900 from C-DTX)		(6,522)	0	0	0
240	ADFIT - Common Plant (283750 from C-DTX)		(49)	0	0	0
241	ADFIT - Bond Redemptions		(481)	0	0	0
242	**TOTAL ACCUMULATED DFIT**		**(46,513)**	**0**	**0**	**0**
243						
244	**NET GAS UTILITY PLANT**		**164,239**	**0**	**0**	**0**
245						
246	GAS INVENTORY					
247	Gas Stored - Recoverable Base Gas		1,261	0	0	0
248	Gas Inventory - Jackson Prairie		1,632	0	0	0
249	Gas Inventory - Jackson Prairie Expansion		185	0	0	0
250	Gas Inventory - Mist		0	0	0	0
251	Working Capital		2,197	0	0	0
252	**TOTAL GAS INVENTORY**		**5,275**	**0**	**0**	**0**
253						
254	OTHER REGULATORY ASSETS					
255	Prepaid Pension, Net of ADFIT		0	0	0	0
256	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**0**
257						
258	**NET RATE BASE**		**169,514**	**0**	**0**	**0**
259						
260	RATE OF RETURN		**4.91%**			
261						
262	**REVENUE REQUIREMENT**		**8,211**	**(186)**	**(5)**	**17**

263 (1) Lines have been hidden in order to provide summarized information.

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED HISTORICAL 2014 AMA BASE YEAR
TWELVE MONTH BASE YEAR ENDED DECEMBER 31, 2014

Line No. (1)	Description		Weather Normalization Sales/Purch	Restate Debt Adjustment	Materials & Supplies Investment	Restated Historical 2014 AMA Base Year Total
	Adjustment Number		1.04	1.05	1.06	
	Workpaper Reference		G-WN	G-RD	G-MS	
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		9,193	0	0	92,833
12	TRANSPORTATION REVENUES		0	0	0	3,146
19	OTHER OPERATING REVENUES		0	0	0	167
21	**TOTAL GAS REVENUES**		9,193	0	0	96,146
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		5,218	0	0	48,290
37	TOTAL OTHER GAS SUPPLY EXPENSE		5	0	0	507
39	**TOTAL PRODUCTION EXPENSES**		5,223	0	0	48,797
40						
45	TOTAL UG STORAGE OPER EXP		0	0	0	134
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	0	114
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	64
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		0	0	0	312
56						
79	DISTRIBUTION O&M EXPENSES		0	0	0	7,660
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	0	4,954
88	TOTAL DISTRIBUTION NON-FIT TAXES		202	0	0	4,452
92	**TOTAL DISTRIBUTION EXPENSES**		202	0	0	17,066
93						
101	**CUSTOMER ACCOUNTS OPERATING EXP**		51	0	0	3,530
107	**CUSTOMER SVC & INFO OPERATING EXP**		0	0	0	580
113	**SALES OPERATING EXPENSES**		0	0	0	0
114						
129	ADMIN & GENERAL OPERATING EXP		31	0	0	8,567
132	TOTAL A&G DEPRCIATION EXP		0	0	0	1,575
137	TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	1,194
139	TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	0	0	2,769
140						
141	**TOTAL ADMIN & GENERAL EXPENSES**		31	0	0	11,336
142						
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		0	0	0	(1)
150						
151	**TOTAL EXPENSES BEFORE FIT**		5,507	0	0	81,620
152						
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		3,686	0	0	14,526
154						
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	1,187	0	0	(7,269)
156	DEBT INTEREST	2.858%	0	60	1	61
157	DEFERRED INCOME TAX		0	0	0	11,270
158	STATE INCOME TAXES	8.00%	295	0	0	(108)
159	**GAS NET OPERATING INCOME (LOSS)**		2,204	(60)	(1)	10,573
160						
161	**RATE BASE**					
162	**PLANT IN SERVICE**					
167	TOTAL INTANGIBLE PLANT		0	0	0	7,234
183	TOTAL UNDERGROUND STORAGE PLANT		0	0	0	5,863
189	TOTAL PRODUCTION PLANT		0	0	0	8
203	TOTAL DISTRIBUTION PLANT		0	0	0	273,959
217	TOTAL GAS GENERAL PLANT		0	0	0	25,703
219	**GROSS PLANT IN SERVICE**		0	0	0	312,767
220						
225	TOTAL ACCUMULATED DEPRECIATION		0	0	0	(99,090)
226						
231	TOTAL ACCUMULATED AMORTIZATION		0	0	0	(2,925)
233	**TOTAL ACCUMULATED DEPR/AMORT**		0	0	0	(102,015)
234						
235	NET GAS UTILITY PLANT before ADFIT		0	0	0	210,752
236						
237	ACCUMULATED DFIT					
238	ADFIT - Gas Plant in Service		0	0	0	(39,461)
239	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	(6,522)
240	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	(49)
241	ADFIT - Bond Redemptions		0	0	0	(481)
242	**TOTAL ACCUMULATED DFIT**		0	0	0	(46,513)
243						
244	**NET GAS UTILITY PLANT**		0	0	0	164,239
245						
246	GAS INVENTORY					
247	Gas Stored - Recoverable Base Gas		0	0	0	1,261
248	Gas Inventory - Jackson Prairie		0	0	0	1,632
249	Gas Inventory - Jackson Prairie Expansion		0	0	0	185
250	Gas Inventory - Mist		0	0	0	0
251	Working Capital		0	0	(46)	2,151
252	**TOTAL GAS INVENTORY**		0	0	(46)	5,229
253						
254	OTHER REGULATORY ASSETS					
255	Prepaid Pension, Net of ADFIT		0	0	0	0
256	**TOTAL OTHER REGULATORY ASSETS**		0	0	0	0
257						
258	**NET RATE BASE**		0	0	(46)	169,468
259						
260	RATE OF RETURN					6.24%
261						
262	**REVENUE REQUIREMENT**		(3,803)	104	(5)	4,331
263	(1) Lines have been hidden in order to provide summarized information.					

AVISTA UTILITIES
OREGON NATURAL GAS
FORECASTED 2016 AMA RESULTS OF OPERATIONS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No. (1)	Description		Restated Historical 2014 AMA Base Year Total	2016 Test Year Expense Adjustment	2016 Test Year Revenue Load Adjustment
	Adjustment Number			2.00	2.01
	Workpaper Reference			G-FE	G-FR
	REVENUES				
8	SALES TO ULTIMATE CUSTOMERS		92,833	0	(43,169)
12	TRANSPORTATION REVENUES		3,146	0	414
19	OTHER OPERATING REVENUES		167	0	0
21	**TOTAL GAS REVENUES**		**96,146**	**0**	**(42,755)**
22					
23	**EXPENSES**				
28	TOTAL GAS PURCHASES		48,290	0	(48,290)
37	TOTAL OTHER GAS SUPPLY EXPENSE		507	1	1
39	**TOTAL PRODUCTION EXPENSES**		**48,797**	**1**	**(48,289)**
40					
41	UNDERGROUND STORAGE EXPENSES:				
45	TOTAL UG STORAGE OPER EXP		134	2	0
48	TOTAL UG STORAGE DEPRCIATION EXP		114	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		64	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**312**	**2**	**0**
56					
79	DISTRIBUTION O&M EXPENSES		7,660	62	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		4,954	0	0
88	TOTAL DISTRIBUTION NON-FIT TAXES		4,452	0	(940)
92	**TOTAL DISTRIBUTION EXPENSES**		**17,066**	**62**	**(940)**
93					
101	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,530**	**14**	**(235)**
107	**CUSTOMER SVC & INFO OPERATING EXP**		**580**	**5**	**0**
113	**SALES OPERATING EXPENSES**		**0**	**0**	**0**
114					
129	ADMIN & GENERAL OPERATING EXP		8,567	76	(146)
132	TOTAL A&G DEPRCIATION EXP		1,575	0	0
137	TOTAL A&G AMRT/NON-FIT TAXES		1,194	0	0
141	**TOTAL ADMIN & GENERAL EXPENSES**		**11,336**	**76**	**(146)**
142					
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**(1)**	**0**	**0**
150					
151	**TOTAL EXPENSES BEFORE FIT**		**81,620**	**160**	**(49,610)**
152					
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**14,526**	**(160)**	**6,855**
154					
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	(7,269)	(52)	2,207
156	DEBT INTEREST	2.770%	61	0	0
157	DEFERRED INCOME TAX		11,270	0	0
158	STATE INCOME TAXES	8.00%	(108)	(13)	548
159	**GAS NET OPERATING INCOME (LOSS)**		**10,573**	**(96)**	**4,099**
160					
161	**RATE BASE**				
167	TOTAL INTANGIBLE PLANT		7,234	0	0
183	TOTAL UNDERGROUND STORAGE PLANT		5,863	0	0
189	TOTAL PRODUCTION PLANT		8	0	0
203	TOTAL DISTRIBUTION PLANT		273,959	0	0
217	TOTAL GAS GENERAL PLANT		25,703	0	0
218					
219	**GROSS PLANT IN SERVICE**		**312,767**	**0**	**0**
220					
221	ACCUMULATED DEPRECIATION				
222	Underground Storage		(572)	0	0
223	Distribution Plant		(90,660)	0	0
224	General Plant		(7,858)	0	0
225	TOTAL ACCUMULATED DEPRECIATION		(99,090)	0	0
226					
231	TOTAL ACCUMULATED AMORTIZATION		(2,925)	0	0
233	**TOTAL ACCUMULATED DEPR/AMORT**		**(102,015)**	**0**	**0**
234					
235	NET GAS UTILITY PLANT before ADFIT		210,752	0	0
236					
237	ACCUMULATED DFIT				
238	ADFIT - Gas Plant in Service		(39,461)	0	0
239	ADFIT - Common Plant (282900 from C-DTX)		(6,522)	0	0
240	ADFIT - Common Plant (283750 from C-DTX)		(49)	0	0
241	ADFIT - Bond Redemptions		(481)	0	0
242	**TOTAL ACCUMULATED DFIT**		**(46,513)**	**0**	**0**
243					
244	**NET GAS UTILITY PLANT**		**164,239**	**0**	**0**
245					
246	GAS INVENTORY				
247	Gas Stored - Recoverable Base Gas		1,261	0	0
248	Gas Inventory - Jackson Prairie		1,632	0	0
249	Gas Inventory - Jackson Prairie Expansion		185	0	0
250	Gas Inventory - Mist		0	0	0
251	Working Capital		2,151	0	0
252	**TOTAL GAS INVENTORY**		**5,229**	**0**	**0**
253					
254	OTHER REGULATORY ASSETS				
255	Prepaid Pension, Net of ADFIT		0	0	0
256	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**
257					
258	**NET RATE BASE**		**169,468**	**0**	**0**
259					
260	RATE OF RETURN		6.24%		
261					
262	**REVENUE REQUIREMENT**		**4,331**	**165**	**(7,074)**

263 (1) Lines have been hidden in order to provide summarized information.

AVISTA UTILITIES
OREGON NATURAL GAS
FORECASTED 2016 AMA RESULTS OF OPERATIONS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No. (1)	Description		2016 Test Year Labor & Benefits Adjustment	Prepaid Pension Investment	2016 Test Year Property Tax Adjustment	2014 EOP Capital Adjustment
	Adjustment Number		2.02	2.03	2.04	2.05
	Workpaper Reference		G-FLB	G-PPI	G-FPT	G-CAP14
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		0	0	0	0
12	TRANSPORTATION REVENUES		0	0	0	0
19	OTHER OPERATING REVENUES		0	0	0	0
21	**TOTAL GAS REVENUES**		**0**	**0**	**0**	**0**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		0	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		41	0	0	0
39	**TOTAL PRODUCTION EXPENSES**		**41**	**0**	**0**	**0**
40						
41	UNDERGROUND STORAGE EXPENSES:					
45	TOTAL UG STORAGE OPER EXP		0	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**0**	**0**	**0**
56						
79	DISTRIBUTION O&M EXPENSES		418	0	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	0	0
88	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	139	0
92	**TOTAL DISTRIBUTION EXPENSES**		**418**	**0**	**139**	**0**
93						
101	**CUSTOMER ACCOUNTS OPERATING EXP**		**230**	**0**	**0**	**0**
107	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**0**	**0**
113	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
114						
129	ADMIN & GENERAL OPERATING EXP		346	0	0	0
132	TOTAL A&G DEPRCIATION EXP		0	0	0	0
137	TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	0
141	**TOTAL ADMIN & GENERAL EXPENSES**		**346**	**0**	**0**	**0**
142						
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**0**
150						
151	**TOTAL EXPENSES BEFORE FIT**		**1,035**	**0**	**139**	**0**
152						
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**(1,035)**	**0**	**(139)**	**0**
154						
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	(333)	0	(45)	0
156	DEBT INTEREST	2.770%	0	(63)	0	(74)
157	DEFERRED INCOME TAX		0	0	0	0
158	STATE INCOME TAXES	8.00%	(83)	0	(11)	0
159	**GAS NET OPERATING INCOME (LOSS)**		**(619)**	**63**	**(83)**	**74**
160						
161	**RATE BASE**					
167	TOTAL INTANGIBLE PLANT		0	0	0	37
183	TOTAL UNDERGROUND STORAGE PLANT		0	0	0	47
189	TOTAL PRODUCTION PLANT		0	0	0	0
203	TOTAL DISTRIBUTION PLANT		0	0	0	10,627
217	TOTAL GAS GENERAL PLANT		0	0	0	(79)
218						
219	**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**10,632**
220						
221	ACCUMULATED DEPRECIATION					
222	Underground Storage		0	0	0	(57)
223	Distribution Plant		0	0	0	(1,939)
224	General Plant		0	0	0	318
225	TOTAL ACCUMULATED DEPRECIATION		0	0	0	(1,678)
226						
231	TOTAL ACCUMULATED AMORTIZATION		0	0	0	192
233	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**0**	**0**	**(1,486)**
234						
235	NET GAS UTILITY PLANT before ADFIT		0	0	0	9,146
236						
237	ACCUMULATED DFIT					
238	ADFIT - Gas Plant in Service		0	0	0	(3,662)
239	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	1,190
240	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0
241	ADFIT - Bond Redemptions		0	0	0	0
242	**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**(2,472)**
243						
244	**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**6,674**
245						
246	GAS INVENTORY					
247	Gas Stored - Recoverable Base Gas		0	0	0	0
248	Gas Inventory - Jackson Prairie		0	0	0	0
249	Gas Inventory - Jackson Prairie Expansion		0	0	0	0
250	Gas Inventory - Mist		0	0	0	0
251	Working Capital		0	0	0	0
252	**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**
253						
254	OTHER REGULATORY ASSETS					
255	Prepaid Pension, Net of ADFIT		0	5,655	0	0
256	**TOTAL OTHER REGULATORY ASSETS**		**0**	**5,655**	**0**	**0**
257						
258	**NET RATE BASE**		**0**	**5,655**	**0**	**6,674**
259						
260	RATE OF RETURN					
261						
262	**REVENUE REQUIREMENT**		**1,068**	**645**	**143**	**761**

263 (1) Lines have been hidden in order to provide summarized information.

AVISTA UTILITIES
OREGON NATURAL GAS
FORECASTED 2016 AMA RESULTS OF OPERATIONS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No. (1)	Description		2015 EOP Capital Adjustment	2016 AMA Capital Adjustment	Working Capital Adjustment	2016 Test Year Insurance Adjustment
	Adjustment Number		2.06	2.07	2.08	2.09
	Workpaper Reference		G-CAP15	G-CAP16	G-FWC	G-IA
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		0	0	0	0
12	TRANSPORTATION REVENUES		0	0	0	0
19	OTHER OPERATING REVENUES		0	0	0	0
21	**TOTAL GAS REVENUES**		**0**	**0**	**0**	**0**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		0	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	0	0
39	**TOTAL PRODUCTION EXPENSES**		**0**	**0**	**0**	**0**
40						
41	UNDERGROUND STORAGE EXPENSES:					
45	TOTAL UG STORAGE OPER EXP		0	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		1	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		1	**0**	**0**	**0**
56						
79	DISTRIBUTION O&M EXPENSES		0	0	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		1,579	52	0	0
88	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	0	0
92	**TOTAL DISTRIBUTION EXPENSES**		1,579	52	**0**	**0**
93						
101	**CUSTOMER ACCOUNTS OPERATING EXP**		**0**	**0**	**0**	**0**
107	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**0**	**0**
113	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
114						
129	ADMIN & GENERAL OPERATING EXP		0	0	0	37
132	TOTAL A&G DEPRCIATION EXP		305	0	0	0
137	TOTAL A&G AMRT/NON-FIT TAXES		1,246	0	0	0
141	**TOTAL ADMIN & GENERAL EXPENSES**		1,551	**0**	**0**	37
142						
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**0**
150						
151	**TOTAL EXPENSES BEFORE FIT**		3,131	52	**0**	37
152						
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		(3,131)	(52)	**0**	(37)
154						
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	(1,008)	(17)	0	(12)
156	DEBT INTEREST	2.770%	(367)	(22)	(12)	0
157	DEFERRED INCOME TAX		0	0	0	0
158	STATE INCOME TAXES	8.00%	(251)	(4)	0	(3)
159	**GAS NET OPERATING INCOME (LOSS)**		(1,505)	(9)	12	(22)
160						
161	**RATE BASE**					
167	TOTAL INTANGIBLE PLANT		10,829	0	0	0
183	TOTAL UNDERGROUND STORAGE PLANT		130	0	0	0
189	TOTAL PRODUCTION PLANT		0	0	0	0
203	TOTAL DISTRIBUTION PLANT		28,903	2,049	0	0
217	TOTAL GAS GENERAL PLANT		3,157	0	0	0
218						
219	**GROSS PLANT IN SERVICE**		43,019	2,049	**0**	**0**
220						
221	ACCUMULATED DEPRECIATION					
222	Underground Storage		(113)	0	0	0
223	Distribution Plant		(4,880)	(26)	0	0
224	General Plant		(468)	0	0	0
225	TOTAL ACCUMULATED DEPRECIATION		(5,461)	(26)	0	0
226						
231	TOTAL ACCUMULATED AMORTIZATION		(1,349)	0	0	0
233	**TOTAL ACCUMULATED DEPR/AMORT**		(6,810)	(26)	**0**	**0**
234						
235	NET GAS UTILITY PLANT before ADFIT		36,209	2,023	0	0
236						
237	ACCUMULATED DFIT					
238	ADFIT - Gas Plant in Service		(2,236)	(20)	0	0
239	ADFIT - Common Plant (282900 from C-DTX)		(987)	0	0	0
240	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0
241	ADFIT - Bond Redemptions		0	0	0	0
242	**TOTAL ACCUMULATED DFIT**		(3,223)	(20)	**0**	**0**
243						
244	**NET GAS UTILITY PLANT**		32,986	2,003	**0**	**0**
245						
246	GAS INVENTORY					
247	Gas Stored - Recoverable Base Gas		0	0	0	0
248	Gas Inventory - Jackson Prairie		0	0	0	0
249	Gas Inventory - Jackson Prairie Expansion		0	0	0	0
250	Gas Inventory - Mist		0	0	0	0
251	Working Capital		0	0	1,090	0
252	**TOTAL GAS INVENTORY**		**0**	**0**	1,090	**0**
253						
254	OTHER REGULATORY ASSETS					
255	Prepaid Pension, Net of ADFIT		0	0	0	0
256	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**0**
257						
258	**NET RATE BASE**		32,986	2,003	1,090	**0**
259						
260	RATE OF RETURN					
261						
262	**REVENUE REQUIREMENT**		6,991	282	124	38

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AVISTA UTILITIES
OREGON NATURAL GAS
FORECASTED 2016 AMA RESULTS OF OPERATIONS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No. (1)	Description		2016 Test Year IS/IT Adjustment	2016 Test Year Atmospheric Testing Adjustment	Incentive Pay Adjustment	2016 AMA Test Year
	Adjustment Number		2.10	2.11	2.12	
	Workpaper Reference		G-ISIT	G-AT	G-IP	
	REVENUES					
8	SALES TO ULTIMATE CUSTOMERS		0	0	0	49,664
12	TRANSPORTATION REVENUES		0	0	0	3,560
19	OTHER OPERATING REVENUES		0	0	0	167
21	**TOTAL GAS REVENUES**		**0**	**0**	**0**	**53,391**
22						
23	**EXPENSES**					
28	TOTAL GAS PURCHASES		0	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	0	550
39	**TOTAL PRODUCTION EXPENSES**		**0**	**0**	**0**	**550**
40						
41	UNDERGROUND STORAGE EXPENSES:					
45	TOTAL UG STORAGE OPER EXP		0	0	0	136
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	0	115
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	64
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**0**	**0**	**315**
56						
79	DISTRIBUTION O&M EXPENSES		0	163	0	8,303
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	0	6,585
88	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	0	3,651
92	**TOTAL DISTRIBUTION EXPENSES**		**0**	**163**	**0**	**18,539**
93						
101	**CUSTOMER ACCOUNTS OPERATING EXP**		**0**	**0**	**0**	**3,539**
107	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**0**	**585**
113	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**
114						
129	ADMIN & GENERAL OPERATING EXP		263	0	(204)	8,939
132	TOTAL A&G DEPRCIATION EXP		0	0	0	1,880
137	TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	2,440
141	**TOTAL ADMIN & GENERAL EXPENSES**		**263**	**0**	**(204)**	**13,259**
142						
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**(1)**
150						
151	**TOTAL EXPENSES BEFORE FIT**		**263**	**163**	**(204)**	**36,786**
152						
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**(263)**	**(163)**	**204**	**16,605**
154						
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	(85)	(52)	66	(6,600)
156	DEBT INTEREST	2.770%	0	0	0	(478)
157	DEFERRED INCOME TAX		0	0	0	11,270
158	STATE INCOME TAXES	8.00%	(21)	(13)	16	58
159	**GAS NET OPERATING INCOME (LOSS)**		**(157)**	**(97)**	**122**	**12,355**
160						
161	**RATE BASE**					
167	TOTAL INTANGIBLE PLANT		0	0	0	18,100
183	TOTAL UNDERGROUND STORAGE PLANT		0	0	0	6,040
189	TOTAL PRODUCTION PLANT		0	0	0	8
203	TOTAL DISTRIBUTION PLANT		0	0	0	315,538
217	TOTAL GAS GENERAL PLANT		0	0	0	28,781
218						
219	**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**368,467**
220						
221	ACCUMULATED DEPRECIATION					
222	Underground Storage		0	0	0	(742)
223	Distribution Plant		0	0	0	(97,505)
224	General Plant		0	0	0	(8,008)
225	TOTAL ACCUMULATED DEPRECIATION		0	0	0	(106,255)
226						
231	TOTAL ACCUMULATED AMORTIZATION		0	0	0	(4,082)
233	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**0**	**0**	**(110,337)**
234						
235	NET GAS UTILITY PLANT before ADFIT		0	0	0	258,130
236						
237	ACCUMULATED DFIT					
238	ADFIT - Gas Plant in Service		0	0	0	(45,379)
239	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	(6,319)
240	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	(49)
241	ADFIT - Bond Redemptions		0	0	0	(481)
242	**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**(52,228)**
243						
244	**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**205,902**
245						
246	GAS INVENTORY					
247	Gas Stored - Recoverable Base Gas		0	0	0	1,261
248	Gas Inventory - Jackson Prairie		0	0	0	1,632
249	Gas Inventory - Jackson Prairie Expansion		0	0	0	185
250	Gas Inventory - Mist		0	0	0	0
251	Working Capital		0	0	0	3,241
252	**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**6,319**
253						
254	OTHER REGULATORY ASSETS					
255	Prepaid Pension, Net of ADFIT		0	0	0	5,655
256	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**5,655**
257						
258	**NET RATE BASE**		**0**	**0**	**0**	**217,876**
259						
260	RATE OF RETURN					5.67%
261						
262	**REVENUE REQUIREMENT**		**271**	**168**	**(211)**	**7,704**

263 (1) Lines have been hidden in order to provide summarized information.

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED 2016 AMA TEST YEAR
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No. (1)	Description		2016 AMA Test Year	Uncollectible Expense Adjustment	Memberships and Dues Adjustment
	Adjustment Number			3.00	3.01
	Workpaper Reference			G-UE	G-MD
	REVENUES				
8	SALES TO ULTIMATE CUSTOMERS		49,664	0	0
12	TRANSPORTATION REVENUES		3,560	0	0
19	OTHER OPERATING REVENUES		167	0	0
21	**TOTAL GAS REVENUES**		**53,391**	**0**	**0**
22					
23	**EXPENSES**				
28	TOTAL GAS PURCHASES		0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		550	0	0
39	**TOTAL PRODUCTION EXPENSES**		**550**	**0**	**0**
40					
45	TOTAL UG STORAGE OPER EXP		136	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		115	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		64	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**315**	**0**	**0**
56					
79	DISTRIBUTION O&M EXPENSES		8,303	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		6,585	0	0
88	TOTAL DISTRIBUTION NON-FIT TAXES		3,651	0	0
92	**TOTAL DISTRIBUTION EXPENSES**		**18,539**	**0**	**0**
93					
101	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,530**	**(259)**	**0**
107	**CUSTOMER SVC & INFO OPERATING EXP**		**585**	**0**	**0**
113	**SALES OPERATING EXPENSES**		**0**	**0**	**0**
114					
129	ADMIN & GENERAL OPERATING EXP		8,939	0	(36)
132	TOTAL A&G DEPRCIATION EXP		1,880	0	0
137	TOTAL A&G AMRT/NON-FIT TAXES		2,440	0	0
141	**TOTAL ADMIN & GENERAL EXPENSES**		**13,259**	**0**	**(36)**
142					
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**(1)**	**0**	**0**
150					
151	**TOTAL EXPENSES BEFORE FIT**		**36,786**	**(259)**	**(36)**
152					
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		**16,605**	**259**	**36**
154					
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	(6,600)	83	12
156	DEBT INTEREST	2.770%	(478)	0	0
157	DEFERRED INCOME TAX		11,270	0	0
158	STATE INCOME TAXES	7.60%	58	21	3
159	**GAS NET OPERATING INCOME (LOSS)**		**12,355**	**155**	**22**
160					
161	**RATE BASE**				
162	**PLANT IN SERVICE**				
167	TOTAL INTANGIBLE PLANT		18,100	0	0
183	TOTAL UNDERGROUND STORAGE PLANT		6,040	0	0
189	TOTAL PRODUCTION PLANT		8	0	0
203	TOTAL DISTRIBUTION PLANT		315,538	0	0
217	TOTAL GAS GENERAL PLANT		28,781	0	0
219	**GROSS PLANT IN SERVICE**		**368,467**	**0**	**0**
220					
221	ACCUMULATED DEPRECIATION				
222	Underground Storage		(742)	0	0
223	Distribution Plant		(97,505)	0	0
224	General Plant		(8,008)	0	0
225	TOTAL ACCUMULATED DEPRECIATION		(106,255)	0	0
226					
231	TOTAL ACCUMULATED AMORTIZATION		(4,082)	0	0
233	**TOTAL ACCUMULATED DEPR/AMORT**		**(110,337)**	**0**	**0**
234					
235	NET GAS UTILITY PLANT before ADFIT		258,130	0	0
236					
237	ACCUMULATED DFIT				
238	ADFIT - Gas Plant in Service		(45,379)	0	0
239	ADFIT - Common Plant (282900 from C-DTX)		(6,319)	0	0
240	ADFIT - Common Plant (283750 from C-DTX)		(49)	0	0
241	ADFIT - Bond Redemptions		(481)	0	0
242	**TOTAL ACCUMULATED DFIT**		**(52,228)**	**0**	**0**
243					
244	**NET GAS UTILITY PLANT**		**205,902**	**0**	**0**
245					
246	GAS INVENTORY				
247	Gas Stored - Recoverable Base Gas		1,261	0	0
248	Gas Inventory - Jackson Prairie		1,632	0	0
249	Gas Inventory - Jackson Prairie Expansion		185	0	0
250	Gas Inventory - Mist		0	0	0
251	Working Capital		3,241	0	0
252	**TOTAL GAS INVENTORY**		**6,319**	**0**	**0**
253					
254	OTHER REGULATORY ASSETS				
255	Prepaid Pension, net of ADFIT		5,655	0	0
256	**TOTAL OTHER REGULATORY ASSETS**		**5,655**	**0**	**0**
257					
258	**NET RATE BASE**		**217,876**	**0**	**0**
259					
260	RATE OF RETURN		5.67%		
261					
262	**REVENUE REQUIREMENT**		**7,704**	**(267)**	**(37)**

263 (1) Lines have been hidden in order to provide summarized information.

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED 2016 AMA TEST YEAR
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No. (1)	Description		State Income Tax Adjustment	Restated Salaries & Wages Adjustment	Restated 2016 AMA Test Year
	Adjustment Number		3.02	3.03	
	Workpaper Reference		G-SIT	G-SW	
	REVENUES				
8	SALES TO ULTIMATE CUSTOMERS		0	0	49,664
12	TRANSPORTATION REVENUES		0	0	3,560
19	OTHER OPERATING REVENUES		0	0	167
21	**TOTAL GAS REVENUES**		0	0	53,391
22					
23	**EXPENSES**				
28	TOTAL GAS PURCHASES		0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	550
39	**TOTAL PRODUCTION EXPENSES**		0	0	550
40					
45	TOTAL UG STORAGE OPER EXP		0	0	136
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	115
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	64
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		0	0	315
56					
79	DISTRIBUTION O&M EXPENSES		0	0	8,303
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	6,585
88	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	3,651
92	**TOTAL DISTRIBUTION EXPENSES**		0	0	18,539
93					
101	**CUSTOMER ACCOUNTS OPERATING EXP**		0	0	3,280
107	**CUSTOMER SVC & INFO OPERATING EXP**		0	0	585
113	**SALES OPERATING EXPENSES**		0	0	0
114					
129	ADMIN & GENERAL OPERATING EXP		0	(95)	8,808
132	TOTAL A&G DEPRCIATION EXP		0	0	1,880
137	TOTAL A&G AMRT/NON-FIT TAXES		0	0	2,440
141	**TOTAL ADMIN & GENERAL EXPENSES**		0	(95)	13,128
142					
149	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		0	0	(1)
150					
151	**TOTAL EXPENSES BEFORE FIT**		0	(95)	36,396
152					
153	**NET OPERATING INCOME (LOSS) BEFORE FIT/SIT**		0	95	16,995
154					
155	FEDERAL INCOME TAX--Normal Accrual	35.00%	(393)	31	(6,868)
156	DEBT INTEREST	2.770%	0	1	(478)
157	DEFERRED INCOME TAX		0	0	11,270
158	STATE INCOME TAXES	7.60%	1,124	8	1,213
159	**GAS NET OPERATING INCOME (LOSS)**		(731)	56	11,857
160					
161	**RATE BASE**				
162	**PLANT IN SERVICE**				
167	TOTAL INTANGIBLE PLANT		0	0	18,100
183	TOTAL UNDERGROUND STORAGE PLANT		0	0	6,040
189	TOTAL PRODUCTION PLANT		0	0	8
203	TOTAL DISTRIBUTION PLANT		0	0	315,538
217	TOTAL GAS GENERAL PLANT		0	(52)	28,729
219	**GROSS PLANT IN SERVICE**		0	(52)	368,415
220					
221	ACCUMULATED DEPRECIATION				
222	Underground Storage		0	0	(742)
223	Distribution Plant		0	0	(97,505)
224	General Plant		0	0	(8,008)
225	TOTAL ACCUMULATED DEPRECIATION		0	0	(106,255)
226					
231	TOTAL ACCUMULATED AMORTIZATION		0	0	(4,082)
233	**TOTAL ACCUMULATED DEPR/AMORT**		0	0	(110,337)
234					
235	NET GAS UTILITY PLANT before ADFIT		0	(52)	258,078
236					
237	ACCUMULATED DFIT				
238	ADFIT - Gas Plant in Service		0	0	(45,379)
239	ADFIT - Common Plant (282900 from C-DTX)		0	0	(6,319)
240	ADFIT - Common Plant (283750 from C-DTX)		0	0	(49)
241	ADFIT - Bond Redemptions		0	0	(481)
242	**TOTAL ACCUMULATED DFIT**		0	0	(52,228)
243					
244	**NET GAS UTILITY PLANT**		0	(52)	205,850
245					
246	GAS INVENTORY				
247	Gas Stored - Recoverable Base Gas		0	0	1,261
248	Gas Inventory - Jackson Prairie		0	0	1,632
249	Gas Inventory - Jackson Prairie Expansion		0	0	185
250	Gas Inventory - Mist		0	0	0
251	Working Capital		0	0	3,241
252	**TOTAL GAS INVENTORY**		0	0	6,319
253					
254	OTHER REGULATORY ASSETS				
255	Prepaid Pension, net of ADFIT		0	0	5,655
256	**TOTAL OTHER REGULATORY ASSETS**		0	0	5,655
257					
258	**NET RATE BASE**		0	(52)	217,824
259					
260	RATE OF RETURN				5.44%
261					
262	**REVENUE REQUIREMENT**		1,261	(104)	8,557

263 (1) Lines have been hidden in order to provide summarized information.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

JENNIFER S. SMITH
Exhibit No. 502

Revenue Requirement and Allocations

AVISTA UTILITIES
OREGON JURISDICTION
NATURAL GAS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No.		Acct. No.	Description	PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2016 AMA Test Year	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Proposed Total (AMA)
	REVENUES			a	b	c	d	e
1			SALES OF GAS:					
2		480000	Residential	54,586	(18,178)	36,408	8,557	44,965
3		481200	Commercial	28,934	(12,916)	16,018	0	16,018
4		481300	Industrial-Firm	528	(81)	447	0	447
5		481400	Interruptible	529	(1,464)	(935)	0	(935)
6		484000	Interdepartmental Sales	16	0	16	0	16
7		499000	Unbilled Revenue	(2,290)	0	(2,290)	0	(2,290)
8			SALES TO ULTIMATE CUSTOMERS	82,303	(32,639)	49,664	8,557	58,221
9								
10			TRANSPORTATION REVENUES					
11		489300	Transportation - Commercial/Industrial	3,191	369	3,560	0	3,560
12			TRANSPORTATION REVENUES	3,191	369	3,560	0	3,560
13								
14			OTHER OPERATING REVENUES:					
15		483XXX	Sales For Resale	115,400	(115,400)	0	0	0
16		488000	Miscellaneous Service Revenues	166	0	166	0	166
17		493000	Other Gas Revenue - Gas Property Rent	1	0	1	0	1
18		495XXX	Other Gas Revenues	28	(28)	0	0	0
19			OTHER OPERATING REVENUES	115,595	(115,428)	167	0	167
20								
21	**TOTAL GAS REVENUES**			**201,089**	**(147,698)**	**53,391**	**8,557**	**61,948**
22								
23	EXPENSES							
24			PRODUCTION EXPENSES:					
25								
26			GAS PURCHASES					
27	OR-804	804XXX	Gas Purchases	161,753	(161,753)	0	0	0
28			TOTAL GAS PURCHASES	161,753	(161,753)	0	0	0
29								
30			OTHE GAS SUPPLY EXPENSE					
31	OR-805	805XXX	Other Gas Purchases	(5,303)	5,303	0	0	0
32		807000	Purchased Gas Expenses	0	0	0	0	0
33	OR-808	808XXX	Natural Gas Storage Transactions	(1,666)	1,666	0	0	0
34		811000	Gas Used for Products Extraction	(471)	471	0	0	0
35		813000	Other Gas Expenses	466	37	503	0	503
36		813010	Gas Technology Institute (GTI) Expenses	41	6	47	0	47
37			TOTAL OTHER GAS SUPPLY EXPENSE	(6,933)	7,483	550	0	550
38								
39			TOTAL PRODUCTION EXPENSES	154,820	(154,270)	550	0	550
40								
41			UNDERGROUND STORAGE EXPENSES:					
42		814000	Supervision & Engineering	0	0	0	0	0
43		824000	Other Expenses	70	1	71	0	71
44		837000	Other Equipment	64	1	65	0	65
45			TOTAL UG STORAGE OPER EXP	134	2	136	0	136
46								
47	OR-DEPX		Depreciation Expense-Underground Storage	114	1	115	0	115
48			TOTAL UG STORAGE DEPRCIATION EXP	114	1	115	0	115
49								
50	OR-OTX		Taxes Other Than FIT-Underground Storage	64	0	64	0	64
51			TOTAL UG STORAGE NON-FIT TAXES	64	0	64	0	64
52								
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	178	1	179	0	179
54								
55			TOTAL UNDERGROUND STORAGE EXPENSES	312	3	315	0	315
56								

AVISTA UTILITIES
OREGON JURISDICTION
NATURAL GAS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No.		Acct. No.	Description	PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2016 AMA Test Year	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Proposed Total (AMA)
57			DISTRIBUTION EXPENSES:					
58			OPERATION					
59		870000	Supervision & Engineering	692	414	1,106	0	1,106
60		871000	Distribution Load Dispatching	0	0	0	0	0
61		874000	Mains & Services Expenses	1,500	12	1,512	0	1,512
62		875000	Measuring & Reg Sta Exp-General	120	1	121	0	121
63		876000	Measuring & Reg Sta Exp-Industrial	3	0	3	0	3
64		877000	Measuring & Reg Sta Exp-City Gate	6	0	6	0	6
65		878000	Meter & House Regulator Expenses	136	2	138	0	138
66		879000	Customer Installation Expenses	1,016	3	1,019	0	1,019
67		880000	Other Expenses	907	165	1,072	0	1,072
68		881000	Rents	17	0	17	0	17
69								
70			MAINTENANCE					
71		885000	Supervision & Engineering	74	0	74	0	74
72		887000	Mains	1,430	18	1,448	0	1,448
73		889000	Measuring & Reg Sta Exp-General	224	1	225	0	225
74		890000	Measuring & Reg Sta Exp-Industrial	27	0	27	0	27
75		891000	Measuring & Reg Sta Exp-City Gate	20	0	20	0	20
76		892000	Services	729	10	739	0	739
77		893000	Meters & House Regulators	589	4	593	0	593
78		894000	Other Equipment	182	1	183	0	183
79			DISTRIBUTION O&M EXPENSES	7,672	631	8,303	0	8,303
80								
81	OR-DEPX		Depreciation Expense-Distribution	4,954	1,631	6,585	0	6,585
82			TOTAL DISTRIBUTION DEPRCIATION EXP	4,954	1,631	6,585	0	6,585
83								
84	OR-OTX	408120	Municipal Occupation & License Tax	1,489	(1,489)	0	0	0
85	OR-OTX	408120	Franchise Fees - Conversion Factor	1,851	(677)	1,174	188	1,362
86	OR-OTX	408170	R&P Property Tax	2,338	139	2,477	0	2,477
87	OR-OTX	409100	State Income Tax	0	0	0	0	0
88			TOTAL DISTRIBUTION NON-FIT TAXES	5,678	(2,027)	3,651	188	3,839
89								
90			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	10,632	(396)	10,236	188	10,424
91								
92			TOTAL DISTRIBUTION EXPENSES	18,304	235	18,539	188	18,727
93								
94			CUSTOMER ACCOUNTS EXPENSES:					
95		901000	Supervision	86	230	316	0	316
96		902000	Meter Reading Expenses	257	2	259	0	259
97	OR-903	903XXX	Customer Records & Collection Expenses	2,348	5	2,353	0	2,353
98		904000	Uncollectible Accounts	261	(254)	7	0	7
99			Uncollectible Accounts - Conversion Factor	471	(178)	293	47	340
100		905000	Misc Customer Accounts	52	0	52	0	52
101			CUSTOMER ACCOUNTS OPERATING EXP	3,475	(195)	3,280	47	3,327
102								
103			CUSTOMER SERVICE & INFO EXPENSES:					
104	OR-908	908XXX	Customer Assistance Expenses	1,649	(1,474)	175	0	175
105		909000	Advertising	360	3	363	0	363
106		910000	Misc Customer Service & Info Exp	47	0	47	0	47
107			CUSTOMER SVC & INFO OPERATING EXP	2,056	(1,471)	585	0	585
108								
109			SALES EXPENSES:					
110		912000	Demonstrating & Selling Expenses	0	0	0	0	0
111		913000	Advertising	0	0	0	0	0
112		916000	Miscellaneous Sales Expenses	0	0	0	0	0
113			SALES OPERATING EXPENSES	0	0	0	0	0

AVISTA UTILITIES
OREGON JURISDICTION
NATURAL GAS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

Line No.	Acct. No.	Description		PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2016 AMA Test Year	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Proposed Total (AMA)
114								
115		ADMINISTRATIVE & GENERAL EXPENSES:						
116	920000	Salaries		2,886	(6)	2,880	0	2,880
117	921000	Office Supplies & Expenses		581	(2)	579	0	579
118	922000	A&G Expenses Transferred		0	0	0	0	0
119	923000	Outside Services Employed		1,439	(7)	1,432	0	1,432
120	924000	Property Insurance Premium		150	11	161	0	161
121	925XXX	Injuries and Damages		773	24	797	0	797
122	926XXX	Employee Pensions and Benefits		220	(5)	215	0	215
123	928000	Regulatory Commission Expenses		501	9	510	0	510
124	928000	Regulatory Commission Fee Expenses		(29)	294	265	0	265
125		Commission Fees - Conversion Factor		582	(399)	183	29	212
126	930000	Miscellaneous General Expenses		473	(40)	433	0	433
127	931000	Rents		75	1	76	0	76
128	935000	Maintenance of General Plant		1,021	256	1,277	0	1,277
129		ADMIN & GENERAL OPERATING EXP		8,672	136	8,808	29	8,837
130								
131	OR-DEPX	Depreciation Expense-General		1,575	305	1,880	0	1,880
132		TOTAL A&G DEPRCIATION EXP		1,575	305	1,880	0	1,880
133								
134	OR-AMTX	Amortization Expense-General Plant-303000		49	0	49	0	49
135	OR-AMTX	Amortization Expense-Misc IT Intangible Plant-3031XX		1,140	1,246	2,386	0	2,386
136	OR-AMTX	Amortization Expense-General Plant-390200, 396200		5	0	5	0	5
137		TOTAL A&G AMRT/NON-FIT TAXES		1,194	1,246	2,440	0	2,440
138								
139		TOTAL A&G DEPR/AMRT/NON-FIT TAXES		2,769	1,551	4,320	0	4,320
140								
141		TOTAL ADMIN & GENERAL EXPENSES		11,441	1,687	13,128	29	13,157
142								
143		OTHER DEFERRALS AND AMORTIZATIONS:						
144	407330	Senate Bill 408		(1)	0	(1)	0	(1)
145	407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0	0	0
146	407431	Senate Bill 408 Amortization		0	0	0	0	0
147	407321	Reg Amort Roseburg/Medford Deferral		0	0	0	0	0
148	407421	Reg Credit Roseburg/Medford Deferral		0	0	0	0	0
149		TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		(1)	0	(1)	0	(1)
150								
151	**TOTAL EXPENSES BEFORE FIT**			**190,407**	**(154,011)**	**36,396**	**264**	**36,660**
152								
153		NET OPERATING INCOME (LOSS) BEFORE FIT		10,682	6,313	16,995	8,293	25,288
154								
155		FEDERAL INCOME TAX--Normal Accrual	35.00%	(8,507)	1,639	(6,868)	2,671	(4,197)
156		DEBT INTEREST	2.770%	0	(478)	(478)	0	(478)
157		DEFERRED INCOME TAX		11,277	(7)	11,270	0	11,270
158		STATE INCOME TAXES	7.60%	(416)	1,629	1,213	663	1,876
159		GAS NET OPERATING INCOME (LOSS)		8,328	3,529	11,857	4,960	16,817
160								

AVISTA UTILITIES
OREGON JURISDICTION
NATURAL GAS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

			PRESENT RATES			WITH PROPOSED RATES	
Line No.	Acct. No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2016 AMA Test Year	Proposed Revenues & Related Exp	Proposed Total (AMA)
161		RATE BASE					
162		PLANT IN SERVICE					
163		INTANGIBLE PLANT:					
164	303000	Misc Intangible Plant (303000)	1,033	0	1,033	0	1,033
165	3031XX	Misc Intangible IT Plant (3031XX)	6,201	0	6,201	0	6,201
166		Misc Intangible Plant Proforma	0	10,866	10,866	0	10,866
167		TOTAL INTANGIBLE PLANT	7,234	10,866	18,100	0	18,100
168							
169		UNDERGROUND STORAGE PLANT:					
170	350100	Land in Fee	0	0	0	0	0
171	351100	S & I - Wells	0	0	0	0	0
172	351200	S & I - Compress Station	0	0	0	0	0
173	351300	S & I - Meas/Regulating Station	0	0	0	0	0
174	351400	S & I - Office	38	0	38	0	38
175	352000	Wells	2,829	0	2,829	0	2,829
176	352100	Wells - Leases	0	0	0	0	0
177	353000	Lines	62	0	62	0	62
178	354000	Compressor Stn Equipment	2,886	0	2,886	0	2,886
179	355000	Meas & Regulating Equipment	21	0	21	0	21
180	356000	Purification Equipment	0	0	0	0	0
181	357000	Other Equipment	27	0	27	0	27
182		Underground Storage Plant Proforma	0	177	177	0	177
183		TOTAL UNDERGROUND STORAGE PLANT	5,863	177	6,040	0	6,040
184							
185		PRODUCTION PLANT:					
186	304000	Land & Land Rights	8	0	8	0	8
187	311XXX	LPG Equipment	0	0	0	0	0
188		Production Plant Proforma	0	0	0	0	0
189		TOTAL PRODUCTION PLANT	8	0	8	0	8
190							
191		DISTRIBUTION PLANT:					
192	374200	Land & Land Rights	220	0	220	0	220
193	374400	Land Easements	328	0	328	0	328
194	375000	Structures & Improvements	272	0	272	0	272
195	376000	Mains	161,577	0	161,577	0	161,577
196	378000	Measuring & Reg Station Equip-General	4,669	0	4,669	0	4,669
197	379000	Measuring & Reg Station Equip-City Gate	1,387	0	1,387	0	1,387
198	380000	Services	67,990	0	67,990	0	67,990
199	381000	Meters	36,117	0	36,117	0	36,117
200	385000	Industrial Measuring & Reg Sta Equip	1,398	0	1,398	0	1,398
201	387000	Other Equipment	1	0	1	0	1
202		Distribution Plant Proforma	0	41,579	41,579	0	41,579
203		TOTAL DISTRIBUTION PLANT	273,959	41,579	315,538	0	315,538
204							
205		GAS GENERAL PLANT: (From C-GPL)					
206	389XXX	Land & Land Rights	1,087	0	1,087	0	1,087
207	390XXX	Structures & Improvements	10,661	0	10,661	0	10,661
208	391XXX	Office Furniture & Equipment	4,515	0	4,515	0	4,515
209	392XXX	Transportation Equipment	2,915	0	2,915	0	2,915
210	393000	Stores Equipment	57	0	57	0	57
211	394000	Tools, Shop & Garage Equipment	2,306	0	2,306	0	2,306
212	395000	Laboratory Equipment	213	0	213	0	213
213	396XXX	Power Operated Equipment	94	0	94	0	94
214	397XXX	Communications Equipment	3,801	0	3,801	0	3,801
215	398000	Miscellaneous Equipment	54	0	54	0	54
216		General Plant Proforma	0	3,026	3,026	0	3,026
217		TOTAL GAS GENERAL PLANT	25,703	3,026	28,729	0	28,729
218							
219		GROSS PLANT IN SERVICE	312,767	55,648	368,415	0	368,415

AVISTA UTILITIES
OREGON JURISDICTION
NATURAL GAS
TWELVE MONTH TEST YEAR ENDED DECEMBER 31, 2016

			PRESENT RATES			WITH PROPOSED RATES	
Line No.	Acct. No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2016 AMA Test Year	Proposed Revenues & Related Exp	Proposed Total (AMA)
220							
221		ACCUMULATED DEPRECIATION					
222	OR-ADEP	Underground Storage	(572)	(170)	(742)	0	(742)
223	OR-ADEP	Distribution Plant	(90,660)	(6,845)	(97,505)	0	(97,505)
224	OR-ADEP	General Plant	(7,858)	(150)	(8,008)	0	(8,008)
225		TOTAL ACCUMULATED DEPRECIATION	(99,090)	(7,165)	(106,255)	0	(106,255)
226							
227		ACCUMULATED AMORTIZATION					
228	OR-AAMT	General Plant - 303000	(102)	0	(102)	0	(102)
229	OR-AAMT	Misc IT Intangible IT Plant - 3031XX	(2,765)	(1,157)	(3,922)	0	(3,922)
230	OR-AAMT	General Plant - 390200, 396200	(58)	0	(58)	0	(58)
231		TOTAL ACCUMULATED AMORTIZATION	(2,925)	(1,157)	(4,082)	0	(4,082)
232							
233		TOTAL ACCUMULATED DEPR/AMORT	(102,015)	(8,322)	(110,337)	0	(110,337)
234							
235		NET GAS UTILITY PLANT before DFIT	210,752	47,326	258,078	0	258,078
236							
237		ACCUMULATED DFIT					
238	282900	ADFIT - Gas Plant in Service	(39,461)	(5,918)	(45,379)	0	(45,379)
239	282900	ADFIT - Common Plant (282900 from C-DTX)	(6,522)	203	(6,319)	0	(6,319)
240	283750	ADFIT - Common Plant (283750 from C-DTX)	(49)	0	(49)	0	(49)
241	283850	ADFIT - Bond Redemptions	(481)	0	(481)	0	(481)
242		TOTAL ACCUMULATED DFIT	(46,513)	(5,715)	(52,228)	0	(52,228)
243							
244		NET GAS UTILITY PLANT	164,239	41,611	205,850	0	205,850
245							
246		GAS INVENTORY					
247	117100	Gas Stored - Recoverable Base Gas	1,261	0	1,261	0	1,261
248	164100	Gas Inventory - Jackson Prairie	1,632	0	1,632	0	1,632
249	164105	Gas Inventory - Jackson Prairie Expansion	185	0	185	0	185
250	164110	Gas Inventory - Mist	0	0	0	0	0
251		Working Capital	2,197	1,044	3,241	0	3,241
252		TOTAL GAS INVENTORY	5,275	1,044	6,319	0	6,319
253							
254		OTHER REGULATORY ASSETS					
255		Prepaid Pension, Net of ADFIT	0	5,655	5,655	0	5,655
256		TOTAL OTHER REGULATORY ASSETS	0	5,655	5,655	0	5,655
257							
258		NET RATE BASE	169,514	48,310	217,824	0	217,824
259							
260		RATE OF RETURN	4.91%		5.44%		7.72%
261							

AVISTA/600
Schuh

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF KAREN S. SCHUH
REPRESENTING AVISTA CORPORATION

Capital Projects

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Karen K. Schuh. I am employed by Avista Corporation as a Senior Regulatory Analyst in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your educational background and professional experience.

A. I graduated from Eastern Washington University in 1999 with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. After spending six years in the public accounting sector, I joined Avista in January of 2006. Since 2006, I have worked in various positions within the Company in the Finance Department (Plant Accounting and Resource Accounting) and joined the State and Federal Regulation Department as a Regulatory Analyst in 2008. Currently, as a Senior Regulatory Analyst, I am responsible for, among other things, preparing the capital pro forma adjustments in determination of revenue requirements for all jurisdictions.

Q. What is the scope of your testimony?

A. My testimony in this proceeding will cover the Company's capital investments in utility plant through December 31, 2015, as well as capital investments in utility plant related to new customer hookups for calendar-year 2016.

A table of contents for my testimony is as follows:

Description		Page
I.	Introduction	1
II.	Proposed New Capital Investment for Ratemaking	2
III.	Capital Investment Plan and Review	7
IV.	Description of Capital Projects	8
V.	Summary of Adjustments	19

II. PROPOSED NEW CAPITAL INVESTMENT FOR RATEMAKING

Q. What does the Company's request for rate relief include regarding new investment in utility plant to serve customers?

A. In this filing, we are proposing to include in retail rates the costs associated with utility plant through December 31, 2015, as well as the costs associated with utility plant related to revenue growth (new customer hookups) from January 1, 2016 through December 1, 2016. Excluding the costs associated with investment in utility plant during the 12 months ended December 31, 2016, other than new customer hookups, from retail rates will understate the cost of utility plant actually used to serve customers during the period in which new retail rates will be in effect following the conclusion of this case.

Q. Why did the Company include all capital additions through December 31, 2015 on an end of period (EOP) basis, and include only capital additions for new customer hookups in 2016 on an Average of Monthly Averages (AMA) basis from January 1, 2016 through December 31, 2016?

A. The 2016 "test year" should reflect costs and revenues that will fairly represent the period when base rates from this docket will be in effect following a general rate case proceeding. Ratemaking practice in Oregon in the past has generally limited the new plant investment included in retail rates to investment that is transferred to plant in service on or before the new retail rates go into effect. Using an End of Period (EOP) balance as of December 31, 2015, reflects the utility plant in service as of the beginning of the forecasted test year (2016). Additionally, given that the forecasted test year revenues include growth in revenue resulting from customer growth, we believe it is appropriate under the matching principle that the utility plant required to serve these new customers also be included in the test year. Therefore, we have included capital additions for new customer hookups, on an AMA basis from January 1, 2016 through December 31, 2016, in the forecasted test year.

Q. How did you develop rate base for this filing?

A. Avista started with rate base from historical accounting information, which for this case is the AMA balances for the twelve months ended December 31, 2014, and made the following adjustments:

(1) Adjust plant in service, accumulated depreciation, depreciation expense and accumulated deferred federal income taxes (ADFIT) to restate the 2014 AMA

rate base to December 31, 2014 EOP levels[1]. The impacts of retirements in 2014 are included in the base period.

(2) Adjust EOP 2014 net plant to EOP 2015 net plant by extending accumulated depreciation and ADFIT balances on utility plant in service from December 31, 2014 to EOP 2015 balances.

(3) Add additions to plant in service during 2015, including the accumulated depreciation, depreciation expense and ADFIT associated with these additions, on a 2015 EOP basis. This also includes an adjustment for the impact of asset retirements in 2015[2].

(4) Add the capital additions for new customer hookups in calendar year 2016 on an AMA basis. This adjustment includes the depreciation expense, accumulated depreciation and ADFIT associated with these additions.

Company witness Ms. Smith incorporates these adjustments in her revenue requirements computation. The adjustment detail is provided in my workpapers.

Q. What is the net impact of the capital adjustments included in this filing?

A. Net plant rate base (plant cost, net of accumulated depreciation and ADFIT) currently authorized (Docket No. UG-284) is $184,745,000, while the proposed level of rate base for 2016 in this filing is $205,850,000, for a net increase of approximately $21.1 million over rate base included in existing rates.

[1] The Company used new depreciation rates as approved in Order 13-168, Docket UM-1626. The depreciation rates for general plant were changed effective January 1, 2013, as approved in the first phase of the settlement in that docket. The depreciation rates for Oregon direct natural gas plant were implemented July 1, 2014, as approved in Order 14-015, Docket UG-246.

[2] The 2014 test year and the adjustment from AMA 2014 to EOP 2014 capture the impacts of retirements for 2014. The adjustment to capital rate base for 2016 is solely limited to capital related to new customer hookups and, therefore, there are no retirements of equipment in 2016. Thus, 2015 is the only year in which a specific adjustment for retirements is included.

Q. What is driving the investment in utility plant in Oregon?

A. It is necessary for the Company to upgrade and expand its distribution facilities to meet reliability requirements and capacity needs. Other issues driving the need for capital investment include systematic replacement of assets that have reached the end of their useful lives, municipal compliance issues (i.e., street/highway relocations), new customer connections, and the systematic replacement of aged and obsolete technology, to name a few. Additionally, given our commitment to providing our customers with safe and reliable service, the Company is continuing with a 20-year program to systematically remove and replace select portions of the DuPont Aldyl-A pipe found in the Company's natural gas distribution system. A description of these and other capital projects is provided in Section IV.

A significant factor in the growth in net plant investment, or rate base, is the cost of new utility equipment and facilities today, as compared to the cost of the older facilities that are now being replaced. The cost to replace this equipment and facilities today is many times more expensive than when this utility plant was installed decades ago.

Q. What data is available to demonstrate the increase in the cost of utility plant assets that have been added in recent years, as compared to the cost of the facilities being replaced?

A. Using the Handy-Whitman Index Manual[3], the Company analyzed major categories of plant. Illustration No. 1, below, depicts the increases in costs of gas

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[3] "The Handy-Whitman Index of Public Utility Construction Costs", is published by Whitman, Requardt and Associates, Baltimore, Maryland. The most recent index was published in May 2014. The Handy-Whitman Indices of Public Utility Construction Costs show the level of costs for different types of utility construction. Separate indices are maintained for general items of construction, such as reinforced concrete, and specific items of material or equipment, such as pipe or turbo-generators. Handy-Whitman Index numbers are used to trend earlier valuations and original cost at prices prevailing at a certain date.

distribution mains and measurement & regulator station equipment that have been experienced by the utility industry over the past fifty years. This chart shows what these categories of plant have historically cost on a scale relative to current prices (as of 2013, the most recently available index data). For example, as shown in Illustration No. 1, the cost of gas distribution main 50 years ago was approximately 8% of the current replacement cost.

Illustration No. 1:

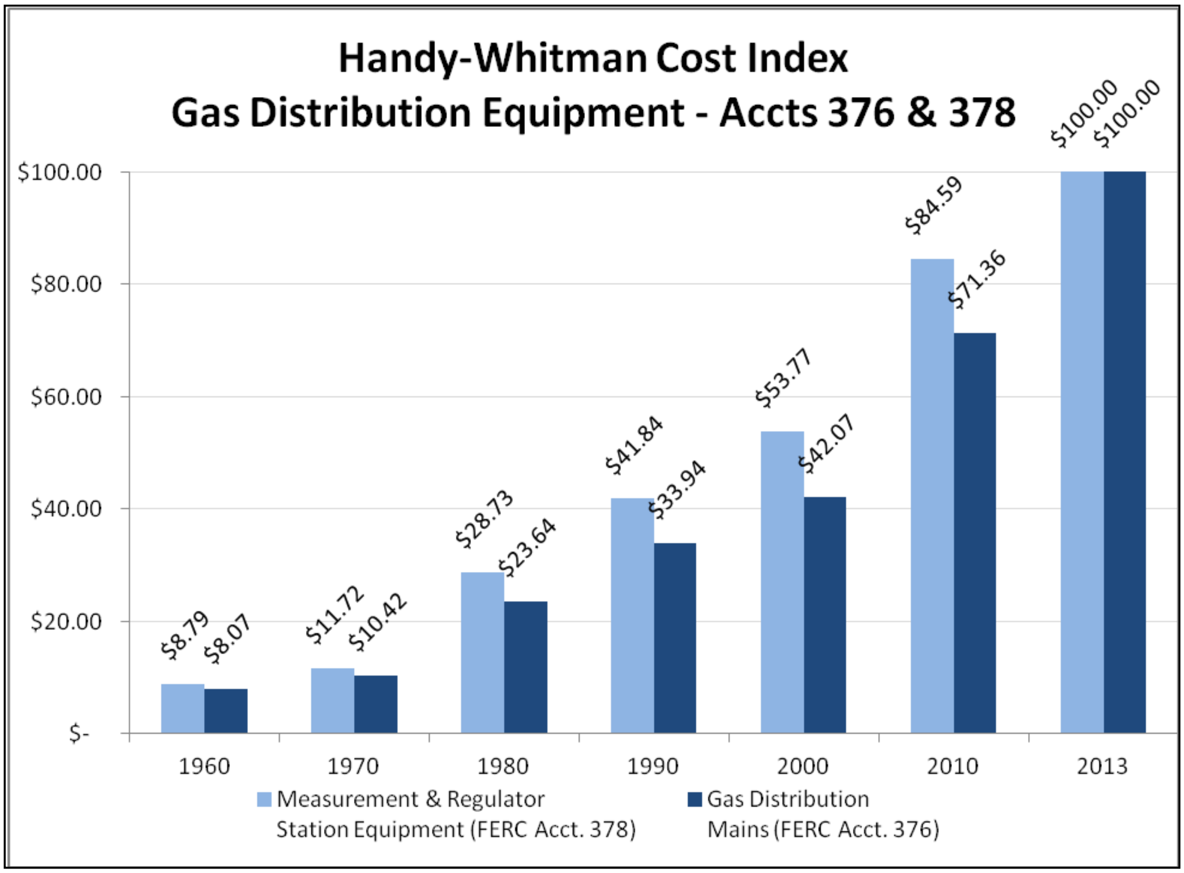


Illustration No. 1, above, shows that the costs of the equipment and facilities added today are many times more expensive than were those same facilities installed in the past. Our retail rates are "cost-based" and reflect the lower cost of the old equipment serving customers (i.e., our rate base comprises a collection of utility assets recorded at their historic costs). When the equipment is replaced, the significantly higher cost of the new equipment is added to rate base, resulting in a larger rate base than was previously present for the asset being replaced, requiring an incremental increase in retail rates.

III. CAPITAL INVESTMENT PLAN AND REVIEW

Q. Please describe Avista's capital budgeting process.

A. Avista's capital budgeting process provides for a detailed review of capital projects, and the progress on those projects, by using "business cases." A business case is a summary document that provides support and analysis for a capital project or program. Components of a business case include the project description, project alternatives, cost summary, business risk, financial assessment, strategic assessment, justification for the project (e.g., mandatory, resource requirements, etc.), milestones, and key performance indicators. The business cases associated with capital additions included in this case have been provided in my workpapers.

The budget process starts with project sponsors submitting new and updated business cases to the Financial Planning and Analysis (FP&A) group for the upcoming five-year period. The business cases are reviewed by FP&A and then included in the list of projects and programs to be considered for funding by the Capital Planning Group (CPG). The CPG is a group of Directors that represent all capital intensive areas of the Company. The CPG meets to review the submitted Business Cases and prioritize funding to conform to the capital budget limits set by senior management. After approval from senior management, the capital budget is sent to the Board of Directors for its approval of the capital budget amount for the five-year period. The CPG meets monthly to review the status of the capital projects and programs, and to approve or decline new business cases as well as monitor the overall capital budget.

Q. Is the Company confident that the level of capital additions that are presented in this case will be completed?

A. Yes. Many of the 2015 projects are already underway, either through actual construction, signed contracts, and/or ordered materials, and in some cases are already completed. Additionally, the capital additions required to serve incremental customers in 2016 are matched with the revenue growth associated with new customers in 2016.

IV. DESCRIPTION OF CAPITAL PROJECTS

Q. What is Avista's capital investment that will transfer to plant in service in 2015 and 2016 in this case?

A. The following Table No. 1 shows Avista's planned system-wide general plant capital transfers to plant of $180.64 million in 2015. Oregon's share of this general plant totals $16.01 million.

Table No. 1
General Plant Capital Projects - 2015 Transfers to Plant

Project	ER	2015 System (000's)	2015 Oregon Allocated (000's)
SCADA Upgrade	2277	$ 1,020	$ 89
Technology Refresh to Sustain Business Process	5005	21,379	1,860
Technology Expansion to Enable Business Process	5006	7,431	647
Enterprise Business Continuity	5010	649	56
Enterprise Security Systems	5014	5,400	470
Next Generation Radio System	5106	4,200	365
Microwave Replacement with Fiber	5121	2,755	240
Customer Information and Asset System Replacement	5138	95,386	8,300
AvistaUtilities.com Redevelopment	5143	7,038	612
Mobility in the Field	5144	420	37
Subtotal - Technology Projects		145,678	12,676
Transportation Equipment	7000	7,834	959
Structures and Improvements	7001	3,400	296
Office Furniture	7003	1,200	104
Stores Equipment	7005	648	56
Tools Lab & Shop Equipment	7006	1,719	167
Battery Storage Strategic Initiative[3]	7060	2,062	179
COF HVAC Improvement	7101	10,979	955
Long Term Campus Re-Structuring Plan	7126	5,000	435
Long Term Campus Re-Structuring Plan - Phase 2	7131	2,000	174
Apprentice Craft Training	7200	121	11
Subtotal - General Plant Projects		34,963	3,336
TOTAL		$ 180,641	$ 16,012

Table No. 2 and Table No. 3, below, show Avista's planned <u>Oregon natural gas distribution</u> capital expenditures of $30.25 million in 2015, and $2.05 million for 2016.

[4] Following the completion of Avista's revenue requirement for this case, it was identified that this project was inadvertently included within the revenue requirement and should have been excluded. We will correct this in our subsequent capital update for this case.

Table No. 2
Oregon Gas Distribution Capital Projects - 2015 Transfers to Plant

Project	ER	2015 System (000's)	2015 Oregon Allocated (000's)
Gas Revenue Growth Projects	1001	$ 13,545	$ 3,846
Gas Meters Growth Projects	1050	1,880	658
Gas Regulators Growth Projects	1051	330	52
Gas ERT Growth Projects	1053	678	237
Gas Reinforce - Minor Blanket	3000	1,481	761
Replace Deteriorating Gas System	3001	1,000	1,000
Regulator Reliable - Blanket	3002	947	387
Gas Replace - Street & Highway	3003	4,827	3,477
Cathodic Protection - Minor Blanket	3004	950	50
	3005		
Gas Distribution Non-Revenue Projects		6,002	3,602
Overbuilt Pipe Replacement Projects	3006	900	828
Isolated Steel	3007	3,450	850
Aldyl-A Pipe Replacement	3008	18,317	6,298
Gas ERT Replacement Program	3054	402	402
Gas Meter Replacement	3055	1,030	296
Gas Telemetry	3117	400	120
East Medford Reinforcement	3203	5,000	5,000
Ladd Canyon Gate Station Upgrade	3303	1,650	1,650
Bonanza Gate Station Move	3307	600	600
Jackson Prairie Storage	7201	1,356	131
TOTAL		$ 64,745	$ 30,245

Table No. 3
Oregon Gas New Customer Hookups- 2016 AMA Transfers to Plant

Project	ER	2016 Oregon (000's)
Gas Revenue Growth Projects	1001	$ 1,720
Gas Meters Growth Projects	1050	154
Gas Regulators Growth Projects	1051	11
Gas ERT Growth Projects	1053	165
TOTAL		$ 2,050

Q. For the capital projects included in this filing that will transfer to plant in service in 2015 and 2016, please provide a description of the projects.

A. A description of each of the capital projects included in Tables No. 1, 2, and 3 above is provided below. Written business cases supporting each of the capital projects are included in the workpapers submitted with this filing.

Technology (Oregon):

ER 2277: SCADA Upgrade – 2015: $89,000
This program replaces and/or upgrades existing electric and gas control center telecommunications and computing systems as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing constraints. This program includes hardware, software, and operating system upgrades, as well as deployment of capabilities to meet new operational standards and requirements. Some system upgrades may be initiated by other requirements, including NERC reliability standards, growth, and external projects (e.g. Smart Grid). Examples of upgrades to be completed under this program are Critical Infrastructure Protection version 5 (NERC requirement), Gas Control Room Management (PHMSA requirement), WECC RC Advanced Applications, and Technology Refresh (network and storage).

ER 5005: Technology Refresh to Sustain Business Process – 2015: $1,860,000
The Company manages an ongoing program to replace, on a systematic basis, aging and obsolete technology under "refresh cycles" that are timed to optimize hardware/software system changes or industry trends. An example of technology managed under this program is the fleet of personal computers and other computing devices used by field operations, power plant operators, call centers, and our general office employees.

ER 5006: Technology Expansion to Enable Business Process – 2015: $647,000
This program facilitates technology growth throughout the Company, including technology expansion for the entire workforce, business process automation and increased technology to support efficient business processes. For example; when the Company adds trucks to the fleet, communication equipment needs to be added to the truck; as the Company hosts more customer data, disk storage needs to be expanded, as customers expand their use of the website, additional computing capacity is needed to support that functionality.

ER 5010: Enterprise Business Continuity – 2015: $56,000
Avista has developed an Enterprise Business Continuity Plan (EBCP) to facilitate emergency response and business continuity activities in fulfillment of our mission to deliver safe and reliable energy to our customers. The program supports the EBCP

objectives by providing an all-hazards framework for emergency response, technology recovery, alternate facilities and business continuity activities. The program provides communications and operational procedures necessary for efficient response to events.

ER 5014: Enterprise Security – 2015: $470,000

There are three primary drivers of the increasing costs for Enterprise Security: cyber security, physical security and regulatory requirements. Each plays a critical role in supporting our delivery of safe and reliable energy to our customers.

Cyber Security

The security of our electric and natural gas infrastructure is a significant priority at a national and state level, and is of critical importance to Avista. Threats from cyber space, including viruses, phishing, and spyware, continue to test our industry's capabilities. While the sources of these malicious intentions are often unknown, it is clear the methods are becoming more advanced and the attacks more persistent. In addition to these threats, the vulnerabilities of hardware and software systems continue to increase, especially with industrial control systems such as those supporting the delivery of energy. For these reasons, Avista must continue to advance its cyber security strategy and invest in security controls to prevent, detect, and respond to these increasingly frequent and sophisticated attacks.

Physical Security

While considerable attention is focused on cyber security, physical security also remains a concern for our industry. Physical security encompasses the aspects of employee safety and the protective security of our facilities. Acts of theft, vandalism, and sabotage of infrastructure not only result in property losses, but can also directly impact our ability to serve customers. Securing remote unmanned or unmonitored critical infrastructure is difficult, especially when traditional tools such as perimeter fencing are not adequate. In response to these challenges, the Company has focused its resources on remote detection and response, which is creating the need for additional expertise and technology.

Regulatory Requirements

Advancing cyber threats continue to drive change in the regulatory landscape faced by the Company. Early in 2013, President Obama issued the Executive Order "Improving Critical Infrastructure Cybersecurity." The Order directed the National Institute of Standards and Technology to work with stakeholders in developing a voluntary framework for reducing cyber risks to critical infrastructure. The Framework consists of standards, guidelines, and best practices to promote the protection of critical infrastructure. The Federal Energy Regulatory Commission also issued Order 791 on November 22, 2013, approving the North American Electric Reliability Corporation Critical Infrastructure Protection Standards, Version 5. Both of these activities will increase our security-related operating costs because they require the Company's security controls and processes to conform to new standards, guidelines, and best practices.

ER 5106: Next Generation Radio – 2015: $365,000

This project refreshes Avista's 20-year-old Land Mobile Radio system. The Company maintains this private system because no public provider is capable of supporting communications throughout our rural service territory. And, since our systems comprise a portion of our nation's critical infrastructure, Avista is required to have a communication system that will operate in the event of a disaster. This project fulfills a mandate from the Federal Communications Commission that all licensees in the Industrial/Business Radio Pool migrate to spectrum efficient narrowband technology.

ER 5121: Microwave Replacement with Fiber – 2015: $240,000

The company manages an ongoing program to systematically-replace aging and obsolete technology under "refresh cycles" that are timed to optimize hardware/software system changes. This project will replace aging microwave communications technology with current technology to provide for high speed data communications. These communication systems support relay and protection schemes of the electrical transmission system. Reducing Avista's risk of failure of these critical communication systems will have a significant impact on Avista's transmission capacity and ability to serve our customers electrical needs.

ER 5138: Customer Information and Work and Asset Management System Replacement – 2015: $8,300,000

The Company's legacy Customer Information and Work and Asset Management System has been in service for twenty years and was replaced in a multi-year effort named "Project Compass." The major applications replaced include the Company's Customer Service System, Work Management System, and the Electric and Gas Meter Application. The primary replacement systems were Oracle's Customer Care & Billing application and International Business Machine's ("IBM") Maximo work and asset management application. A portion of the Maximo system was enabled in the fall of 2013, and the full System was placed in service in February 2015.

ER 5143: AvistaUtilities.com Redevelopment – 2015: $612,000

Like many businesses today, the Company is experiencing continued growth in the use of its customer website, Avistautilities.com. The website was built in 2006-2007, but because the technology landscape has advanced so quickly, the site does not meet current web best practices for customer usability. This project will update and improve the technology, overall web usability, and customer satisfaction. The website is part of the Company's strategy to provide customers a more effective channel to meet their expectations for self-service options, including mobile access, energy efficiency education, and to drive self-service as a means to lower transaction costs.

ER 5144: Mobility in the Field – 2015: $37,000

The Mobility in the Field program is designed to increase the Company's use of field mobile dispatch for service employees equipped with mobile devices. This cost supports the software maintenance agreements that will need to be in place in order to maintain the new system.

Transportation (Oregon):

ER 7000: Transportation Equipment – 2015: $959,000
Expenditures are for the scheduled replacement of trucks, off-road construction equipment and trailers that meet the Company's guidelines for replacement, including age, mileage, hours of use and overall condition. This ER also, includes additions to the fleet for new positions or crews working to support the maintenance and construction of our natural gas operations.

General (Oregon):

ER 7001/7003: Structures and Improvements / Office Furniture - 2015: $296,000/$104,000
This program is for the Capital Maintenance, Improvements, and Furniture budgets at over 50 Avista offices and service centers (over 700,000 square feet in total). Many of the service centers were built in the 1950's and 1960's and are starting to show signs of severe aging. The program includes capital projects in all construction disciplines (roofing, asphalt, electrical, plumbing, HVAC, energy efficiency projects etc.).

ER 7005/7006: Capital Tools & Stores Equipment – 2015: $56,000/$167,000
This program is for equipment utilized in warehouses throughout the service territory. This includes equipment such as forklifts, man-lifts, shelving, cutting/binding machines, etc. Expenditures in this category include all large tools and instruments used throughout the company for natural gas and/or electric construction and maintenance work, distribution, transmission, or generation operations, telecommunications, and some fleet equipment (hoists, winch, etc.) not permanently attached to the vehicle.

ER 7101: HVAC Renovation Project – 2015: $955,000
The HVAC Renovation Project began in 2007. The HVAC Project is a systematic replacement of the original 1956 Heating, Ventilation and Air Conditioning System for the Service Building, Cafeteria/Auditorium and General Office Building. The original HVAC equipment has been operating 24/7 since original construction in 1956. The Project entails a floor by floor evacuation and relocation of employees and a complete demolition of each floor; including a massive Asbestos Abatement component, and removing the original fire proofing on the basic steel structure. The Project requires exhaustive demolition and reconstruction of each floor. Sustainable energy savings and conservation are built into the Project as we apply for LEED certification for each floor. The 5th, 4th, and 3rd floors have obtained LEED-CI Gold status recognizing all of the renewable strategies we employed during the design and construction phases. The goal of this project is to re-purpose and recycle the entire Facility for the next generation of Avista employees. Life cycle costs weighed

heavily on our Construction Specifications and equipment choices during the design phase. The design team chose energy efficient equipment that was designed for 30 to 50 year life cycles.

ER 7126: Central Office Facility (COF) Long Term Campus Restructuring Plan – 2015: $435,000

The central operating facility (COF) campus restructuring plan, phase one, is a two-year, multiple project plan to address material storage, field recovery operations, and office space needs. Over the past few years, our warehouse material inventory has increased and presently the materials are scattered in multiple locations on the COF, due to them outgrowing their allocated space. The campus restructuring will increase and consolidate their storage area, resulting in greater efficiencies for the warehouse and field crews. In addition, two new structures will be built to consolidate transformer recovery (both PCB and non-PCB), hazardous waste & material, and investment recovery (recycling) operations. This will improve the safety and efficiencies for collection of all field recovery materials, as well as provide a one-stop drop location for field crews (instead of the three different locations on the COF right now). Avista is also remodeling two existing areas in our service building that will provide approximately 30 new cubicles, meeting rooms, and offices. This will help accommodate our growth and may allow employees in leased spaces to return to the COF, resulting in a reduction of leased space. In addition, savings are gained as a result of line trucks and employees not having to travel and off-load waste matter that is recyclable or hazardous.

ER 7131: Central Office Facility (COF) Long-Term Restructure Phase 2 – 2015: $174,000

Avista's Central Office Facility (COF) Long Term Restructuring Plan, Phase 2 involves the construction of a new Fleet Vehicle Garage and four story parking structure. By the end of 2015, facilities projects will add approximately 183 new cubicles. Our parking lots will be beyond maximum capacity. The Company currently leases space from Burlington Northern for employee parking. This lease space could be at risk in the future, if Burlington needs the space. The Fleet Garage is over 50 yrs old and is constrained. The new garage will allow for maintenance of Compressed Natural Gas vehicles as the current building does not allow for this. Once Fleet is relocated, there will be a distinct separation between operational/service vehicles and employee vehicles. This separation will increase safety by eliminating intermingling of pedestrians in work areas. The office building & parking garage is projected to allow the Call Center and any leased facilities to come back to Mission campus. The Ross Park conversion to office space will cover any future employee expansion that will occur.

ER 7200: Apprentice Craft Training – 2015: $11,000

This program is for on-going capital improvements to support the essential skills needed for journeyman workers, apprentices and pre-apprentices now and for the future. It is important to provide the types of training scenarios that employees face in the field. Capital expenditures under this program include items such as building new facilities or expanding existing facilities, purchase of equipment needed, or build out of realistic utility field infrastructure used to train employees. Examples include: new or expanded shops, truck canopies, classrooms, backhoes and other equipment, build out of "Safe City" located at the Company's Jack Stewart training facility in Spokane, which could include commercial and residential building replicas, and distribution, transmission, smart grid, metering, gas and substation infrastructure.

Natural Gas Distribution (Oregon):

ER 1001: Gas Revenue Growth Projects – 2015: $3,846,000; 2016: $1,720,000
This annual program addresses costs to serve new loads for natural gas service. This portion of the program includes the cost to construct new gas piping in order to provide service to new customers.

ER 1050: Gas Meters Growth Projects – 2015: $658,000; 2016: $154,000
This annual program addresses costs to serve new loads for natural gas service. This portion of the program includes the cost of new meters and the associated installation of the aforementioned meters in order to provide service to new customers.

ER 1051: Gas Regulators Growth Projects – 2015: $52,000; 2016: $11,000
This annual program addresses costs to serve new loads for natural gas service. This portion of the program includes the cost of new regulators and the associated installation of the aforementioned regulators in order to provide service to new customers.

ER 1053: Gas ERT Growth Projects – 2015: $237,000; 2016: $165,000
This annual program addresses costs to serve new loads for natural gas service. This portion of the program includes the cost of new ERTs and the associated installation of the aforementioned ERTs in order to provide service to new customers.

ER 3000: Gas Reinforcement – Minor Blanket - 2015: $761,000
Avista has an obligation to provide reliable gas service that is of adequate pressure and capacity. Periodic reinforcement of the system is required to serve increased demand reliably at existing service locations and new customers. This annual program will identify and install new sections of gas main to improve the operating reliability and performance of the gas distribution system. Execution of this program on an annual basis will ensure the continuation of reliable gas service that is of adequate pressure and capacity.

ER 3001: Replace Deteriorated Pipe – 2015: $1,000,000
This annual project will replace sections of existing gas piping that are at-risk for failure or have deteriorated within the gas system. This project will address the replacement of sections of gas main that no longer operate reliably and/or safely. Sections of the gas system require replacement due to many factors including material failures, environmental impact, increased leak frequency, or coating

problems. This project will identify and replace sections of main to improve public safety and system reliability.

ER 3002: Regulator Station Reliability Projects – 2015: $387,000

This annual program will replace or upgrade existing regulator stations and meter stations to current Avista standards. This program will address enhancements that will improve system operating performance, enhance safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

ER 3003: Gas Replacement Street and Highways – 2015: $3,477,000

This annual project will replace sections of existing gas piping that require replacement due to relocation or improvement of streets or highways in areas where gas piping is installed. Avista installs many of its facilities in public right-of-way under established franchise agreements. Avista is required under the franchise agreements, in most cases, to relocate its facilities when they are in conflict with road or highway improvements.

ER 3004: Cathodic Protection Projects – 2015: $50,000

This annual project upgrades, replaces, or installs cathodic protection systems required to ensure compliance with PHMSA regulations regarding proper cathodic protection of steel mains. This program will ensure appropriate cathodic protection levels are maintained, reduce corrosion related failures, help prevent leaks within steel pipeline systems, and enhance public safety.

ER 3005: Gas Distribution Non-Revenue Projects – 2015: $3,602,000

This annual project will replace sections of existing gas piping that require replacement to improve the operation of the gas system, but are not directly linked to new revenue. It includes replacement of pipe and facilities that are at the end of their useful life or have failed. It also includes improvement in equipment and/or technology to enhance system operation and/or maintenance, replacement of obsolete facilities, replacement of main to improve cathodic performance, and projects to improve public safety and/or improve system reliability.

ER 3006: Overbuild Pipe Replacement Projects – 2015: $828,000

This annual project will replace sections of existing gas piping that have experienced encroachment or have been overbuilt [customer constructed improvements (i.e., decks, driveways, etc.)], which restricts the Company's access to pipe. It will address the replacement of sections of gas main that are no longer able to be operated safely and will identify and replace sections of main to enhance public safety. All types of overbuilds will be addressed with the primary focus of the project being overbuilds in manufactured home developments.

ER 3007: Isolated Steel Replacement – 2015: $850,000

The Company has implemented a special cathodic protection program for the purpose of finding and addressing isolated steel in its natural gas piping systems.

ER 3008: Aldyl-A Replacement Project – 2015: $6,298,000

The Company is currently undergoing a 20 year program to systematically remove and replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system in the States of Washington, Oregon and Idaho. None of the subject pipe is "high pressure main pipe," but rather, consists of distribution mains at maximum operating pressures of 60 psi and pipe diameters ranging from 1¼ to 4 inches.

ER 3054: Gas ERT Replacement Program – 2015: $402,000

This program covers labor required for the replacement of 19,500 natural gas Encoder Receiver Transmitters (ERTs) annually for a 12-year cycle, beginning in the year 2015. Analyses has identified that a levelized replacement strategy will minimize the effect of unit failures as well as introduce new, levelized populations of ERTs into the system for future predictive maintenance.

ER 3055: Natural Gas Meter Replacement Projects – 2015: $296,000

This annual program provides for replacement of natural gas meters and associated measurement equipment, which are completed in association with the Gas Planned Meter Change-out (PMC) program. Avista is required by commission rules and an approved tariff in WA, ID, and OR to test meters for accuracy and ensure proper metering performance. Execution of this program on an annual basis will ensure the continuation of reliable gas measurement. This program includes the labor and minor materials associated with the PMC program.

ER 3117: Gas Telemetry – 2015: $120,000

The projects will include the installation of six flow computers to replace existing aging infrastructure. Additionally this project includes all new telemetry installations, to include both wireless and hard-wired.

ER 3203: East Medford Reinforcement – 2015: $5,000,000

This project will complete the 12" high-pressure steel pipeline loop across the east side of Medford, Oregon. The length of the remaining segment will be about 3.2 miles. Avista's Gas Integrated Resource Plan requires increased gas deliveries from the TransCanada Pipeline source at Phoenix Road Gate Station in SE Medford. Existing distribution piping exiting the station will be unable to receive the increased gas volumes. A new high-pressure gas line encircling Medford to the east and tying into an existing high pressure line in White City will improve delivery capacity and provide a much needed reinforcement in the East Medford area, which is forecasting higher growth.

ER 3303: Ladd Canyon Gate Station Upgrade – 2015: $1,650,000

The existing gate station has reached its physical capacity due to the growth in the area and needs to be upgraded to support the gas load increases. The new Gate Station will include separate regulation facilities to modify the existing system and maintain service for the Union supply main and the Airport main extension along Pierce Rd. The new facility will require heater, odorizer, regulation, and relief facilities for the Avista site. New telemetry facilities will be installed at this location as well. This project will accommodate the long term benefit of adding capacity to the Elgin area once the 3 miles of HP is extended from Union to the Elgin HP line out of La Grande.

ER 3307: Bonanza Gate Station Move – 2015: $600,000

Gas Transmission Northwest (GTN) has requested that we relocate the metering and odorizing equipment at the Bonanza Meter Station to a nearby location. Working with GTN to move this equipment will allow us to share the costs of this move between parties.

ER 7201: Jackson Prairie Storage Projects – 2015: $131,000

These projects include capital maintenance to the Jackson Prairie Storage facility.

V. SUMMARY OF ADJUSTMENTS

Q. What is the change in natural gas rate base for the capital adjustments included in this testimony?

A. Natural gas net rate base for capital investment increases $39,659,000 from December 31, 2014 AMA results of operations balance of $164,239,000 to a December 31, 2015 EOP balance of $203,898,000. In addition, rate base increases $2,004,000 during 2016, related to new customer hookups, to the 2016 AMA balance of $205,902,000. The total increase in net rate base from the 2014 base year is $41,663,000. Table No. 4 below summarizes the adjustments for capital additions included in this case.

Table No. 4
Summary of Capital Adjustments

In thousands ('000s)	AMA 12.31.14	2.05 2014 Total Adjustment	EOP 12.31.14	2.06 CAP15 2015 Adjustment	EOP BALANCE 12.31.15	2.07 CAP16 2016 Adjustment	AMA BALANCE 12.31.16
Total Plant Cost	312,767	10,633	323,400	43,019	366,419	2,049	368,468
Total Accumulated Depreciation	(102,015)	(1,487)	(103,501)	(6,810)	(110,312)	(26)	(110,337)
Total Accumulated DFIT	(46,513)	(2,472)	(48,985)	(3,224)	(52,209)	(20)	(52,229)
Net Rate Base	164,239	6,674	170,913	32,985	203,898	2,004	205,902

Company witness Ms. Smith includes the following three adjustments in her testimony and exhibits:

<u>2014 EOP Capital Adjustment (**Adjustment 2.05**)</u> – Adjusts the 2014 base year rate base stated on an AMA basis to an EOP basis. The utility plant in service as of December 31, 2014 was adjusted to the EOP basis. Accumulated depreciation and ADFIT were also adjusted to a December 31, 2014 EOP basis.

<u>2015 EOP Capital Adjustment (**Adjustment 2.06**)</u> – First, the plant that was in service at December 31, 2014 was depreciated through December 31, 2015. Additionally, ADFIT was extended to a December 31, 2015 EOP basis. Second, 2015 capital additions were included on a December 31, 2015 EOP basis, including the associated accumulated depreciation and ADFIT. Finally, an adjustment was made to account for retirements of utility plant assets in 2015 on an EOP December 31, 2015 basis. This retirement adjustment serves to reduce depreciation expense for the 2016 forecasted test year.

<u>2016 AMA New Customer Connection Capital Adjustment (**Adjustment 2.07**)</u> – 2016 capital additions from January 1, 2016 through December 31, 2016 directly related to new customer hookups were included on an AMA basis as of December 31, 2016.

Q. What is the impact to <u>expense</u> for the 2016 test year?

A. Depreciation expense increases approximately $977,000, before federal income taxes, as a result of adjusting AMA 2014 depreciation per results of operations to a full year EOP balance for utility property in service at December 31, 2014. Additionally, depreciation expense increases approximately $2,439,000, before federal income taxes, for the capital additions (2015 and 2016) included in this case. Finally, the aforementioned adjustment for asset retirements during 2015 resulted in a decrease of $233,000 to depreciation expense.

These adjustments result in a net increase to depreciation expense of $3,183,000 from the AMA 2014 base year to the 2016 forecasted test year. These increases to depreciation expense are included within adjustments 2.06 and 2.07.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF DR. GRANT D. FORSYTH
REPRESENTING AVISTA CORPORATION

2016 Test Year Load Forecast

I. INTRODUCTION

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

A. My name is Dr. Grant D. Forsyth. I am employed by Avista Corporation as its Chief Economist. My business address is 1411 E. Mission Avenue, Spokane, Washington.

Q. Dr. Forsyth, please provide information pertaining to your educational background and professional experience.

A. I am a graduate of Central Washington University with a Bachelor of Arts Degree in Economics, the University of Oregon with an MBA in Finance, and Washington State University with a Ph.D. in Economics. Before joining Avista in April 2012, I was a tenured faculty member in the Department of Economics at Eastern Washington University ("EWU"). In my 13-year career at EWU, beginning in 1999, I specialized in money and banking, macroeconomics, international finance, and regional economic analysis. The majority of my academic research used applied econometrics. Prior to EWU, I worked in the Czech Republic as an academic economist (1996-1997) and private sector economist (1997-1999) in the Czech financial industry. My financial industry position was the Director of Research for a diversified Czech financial holding company. In this position I oversaw a staff doing both equity and macroeconomic research.

My primary job duties at Avista include (1) generating the customer and load forecasts for electric and natural gas operations;[1] (2) generating the peak load forecast for electric operations; and (3) participating in external policy groups. Current examples of external policy groups include the Washington Governor's Council of Economic Advisors and

[1] My forecasts are used in the Company's revenue model and are frequently used as modeling inputs by the Company's Energy Resources Department.

Washington's Citizen Commission for Performance Measurement of Tax Preferences.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will describe the methodology used to generate the forecasts for customers, use-per-customer, and total load. The results of my forecast are used in the Company's 2016 Test Year Revenue Load Adjustment 2.01 sponsored by Company witness Mr. Ehrbar.

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

A. Yes. I am sponsoring Exhibit No. 701 which was prepared under my direction.

Q. Would you please explain what is contained in Exhibit No. 701?

A. Yes. Exhibit No. 701 contains a more detailed overview of the customer and use-per-customer load forecast, including the variables and equations used to develop those respective forecasts.

Q. Please summarize the main points of your testimony.

A. The main points of my testimony are as follows:

(1) Customer growth for the 2008 – 2014 time period has averaged an annual rate of increase of 0.5 percent. For the 2005 – 2007 time period, the average annual rate of customer growth was 2.5 percent.

(2) Use-per-customer ("UPC") continues to be relatively flat for the Company's residential and commercial customers (which comprise 99.8% of the Company's total customers). Use-per-customer for special contact and transportation customers is forecasted to increase from the base year of 2014 to the test year of 2016, primarily due to the increase in the general business cycle (i.e., increased production).

(3) The combination of low customer growth and flat UPC for the Company's

Schedules 410 and 420 results in a combined 2.2% increase in customer usage from the 2014 base year to the 2016 test year. While the Company's forecast shows a total overall increase in customer usage of 5.4% over the 2014 to 2016 two-year time period, only 33% of the projected load increase is from sales customers (Schedules 410 – 444), with the other 67% coming from transportation and special contract customers (Schedules 447 and 456).

II. OVERVIEW OF THE LOAD FORECAST

Q. Please provide an overview of the Company's natural gas load forecast.

A. Avista's natural gas load forecast is comprised of a number-of-customers forecast and a use-per-customer ("UPC") forecast. These are conducted for each rate schedule, and by customer class (i.e., residential, commercial, and industrial). The customer and UPC forecasts are completed on a monthly basis and extend out five years. For each rate schedule, customer and UPC forecasts are multiplied together in order to produce a monthly (billing month), five-year load forecast. As will be discussed later in my testimony, this load forecast is used in conjunction with the Company's Natural Gas Supply forecast model known as SENDOUT®. SENDOUT® is used by Avista in its natural gas supply purchase decisions.

Q. Where do you provide more granular detail related to the models you use to forecast number of customers and use-per-customer?

A. Provided in Exhibit No. 701 are details and equations related to the weather and non-weather related forecast drivers. Further, this exhibit presents the use-per-customer and customer forecasting models using standard econometric notations.

Q. How is the load forecast used?

A. The load forecast is used (1) in the Company's revenue forecast model; (2) for rate cases and other regulatory purposes; and (3) as the starting point for the long-run forecasts in the Company's Integrated Resource Plans.

Q. How often is the load forecast updated or conducted?

A. The five-year customer and load forecasts are typically updated at least once a year, in the spring.[2] The next forecast is expected to be completed at the end of June 2015. Given current economic conditions, we do not expect a material change in the June 2015 forecast compared to the June 2014 forecast.

III. CUSTOMER FORECAST

Q. What is the methodology behind the customer forecasts and what are the primary forecast drivers?

A. The customer forecasts are based on standard time-series models that rely on the historic customer data to forecast the future. These models range from linear regression models to simple smoothing (averaging) models, depending on the complexity of customer growth over time. The method applied depends on the complexity of past customer growth.

The more complicated linear time-series regression models are applied to Medford, Roseburg, Klamath, and La Grande residential and commercial Schedules 410 and 420. The primary forecast driver is forecasted population growth. Population growth is a direct driver in the Schedule 410 forecast and, as will be discussed, an indirect driver in the Schedule 420 forecast. The emphasis placed on Schedules 410 and 420 reflect their importance in terms of

[2] Depending on how economic conditions evolve, an updated forecast run in the winter is sometimes performed. The decision on whether or not to update the forecast depends on how economic performance has deviated from the forecast's underlying assumptions used in the previous spring.

numbers of customers and load. Table No. 1 below summarizes the total number of customers served on each schedule in 2014, each schedule's percentage of total customers, and each schedule's 2014 calendar usage:

Table No. 1:

Oregon Number of Year-End Customers and 2014 Annual Usage

	Dec. 2014 Customers	Percent of Total Customers	Actual 2014 Usage (therms)
Residential Schedule 410	86,711	88.31%	42,039,996
General Service Schedule 420	11,327	11.54%	23,367,291
Large General Service Schedule 424	81	0.08%	4,085,020
Interruptible Service Schedule 440	33	0.03%	3,699,133
Seasonal Service Schedule 444	2	0.00%	281,182
Special Contract Schedule 447	4	0.00%	7,116,321
Transportation Service Schedule 456	36	0.04%	35,533,020
Overall	**98,194**	**100%**	**116,121,963**

Forecasted population growth is integrated as follows:

(1) For each city area, a base-line customer forecast for Schedule 410 is generated using a time-series regression model;

(2) For each year of the five-year forecast, the annual growth rate of the base-line forecast is compared against the annual forecasted population growth for that city area; and

(3) If there is a large difference between the forecasted population growth rate and forecasted Schedule 410 customer growth, the baseline customer forecast is adjusted up or down to match the population forecast on an annual basis.

This approach is based on the historic norm that Schedule 410 customer growth in each of the Company's service regions is highly correlated with population growth.

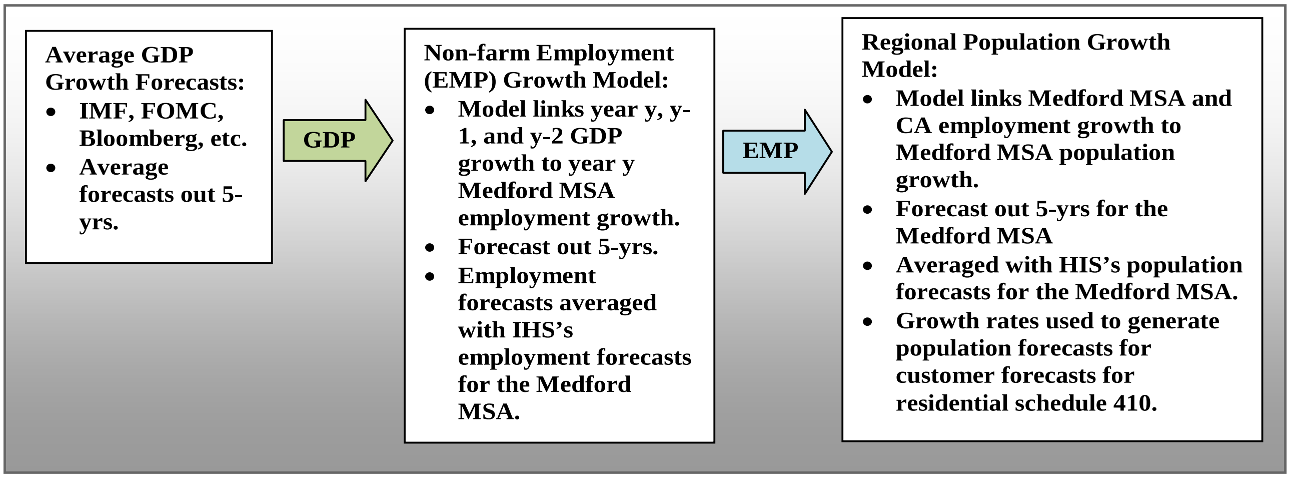
The final Schedule 410 customer forecasts for the Medford, Klamath, and La Grande regions are then used as forecast drivers for the commercial Schedule 420 customer forecasts. This approach is based on the historic norm that residential Schedule 410 and commercial Schedule 420 customer growth in these regions is highly and positively correlated. In the Roseburg region, however, this historic correlation is much weaker. This likely reflects a "leakage" of Roseburg household spending to areas outside the Roseburg area. Therefore, Roseburg's Schedule 410 customer forecast is not used as a driver for the Schedule 420 customer forecast. Given Roseburg's slow growth, a simple time-series econometric model is sufficient for forecasting 410 customers in Roseburg.

Q. What is the methodology behind the population forecast?

A. For the Roseburg, Klamath, and La Grande regions, IHS (formerly Global Insight) forecasts are used. IHS is one of the leading firms providing U.S., state, and county level economic forecasts. IHS is widely used by state governments for forecasting, including the State of Oregon. IHS's forecasts for these three regions change very little year-to-year and adequately capture the slower, less volatile growth of these regions. The forecast for the Medford region averages IHS's forecasts with in-house Company forecasts. As a Metropolitan Statistical Area ("MSA"), the Medford region's economy is more complex and subject to more forecasting uncertainty. Therefore, the Company believes that using two separate forecasts will provide for a better level of forecasting accuracy. By averaging multiple forecasts to generate the final population forecast, the systematic error that can accompany a single source forecast is reduced. Illustration No. 1 below describes the Company's methodology for the Medford region's forecast.

<u>Illustration No. 1:</u>

Forecasting Population Growth in the Medford Region



Avista's forecasting process starts with a forecast of U.S. gross domestic product ("GDP"), averaged from a number of varying forecast sources (the International Monetary Fund ("IMF"), Federal Reserve Open Market Committee ("FOMC"), Bloomberg, etc.). This GDP forecast is then translated via regression analysis in SAS/ETS® into an employment growth forecast for the Medford region, which is then averaged with IHS's employment forecast for the Medford MSA to arrive at a final employment growth forecast. Next, this averaged employment growth forecast is used to generate the Company's forecast for Medford's population growth. Finally, the Company's population growth forecast is averaged with GI's population forecast to arrive at the final, averaged population growth forecast. This averaged population growth forecast is then applied to the base-line Schedule 410 customer forecast discussed previously.

The Medford region population model assumes the primary driver for Medford's population growth is in-migration related to employment opportunities, controlling for the employment growth in California, a large alternative labor market that Medford competes with for migrating individuals. Illustration No. 1 highlights that forecasts for GDP growth and employment growth underlie the population forecast.

Q. Do you anticipate any future changes to the customer forecast methodology as described?

A. Yes. In future forecasts (the current was done in the Spring 2014), population for the Medford region will be integrated directly into the time-series regressions for residential Schedule 410 as an explicit explanatory variable in the regression model. This will be done by interpolating between annual historical population estimates to generate a monthly population series. This new process will streamline the forecasting process and better capture the long-run relationship between Medford's residential customer growth and population growth. The Medford region's annual population forecast will still reflect the average of the in-house and IHS's population growth forecasts as described by Illustration No. 1. As with the historical population data, this annual forecast will be converted into a monthly value that can be directly inputted into the time-series regression. Initial tests of this procedure produced forecasts in line with current forecasts, which have been very close to actuals.

In the case of the other three regions, the 410 customer forecasts will reflect only the baseline forecasts generated by the original regression models. Because the Roseburg, Klamath, and La Grande regions are growing slowly, the current time-series models without a population driver produce forecasts very similar to IHS's population forecasts.

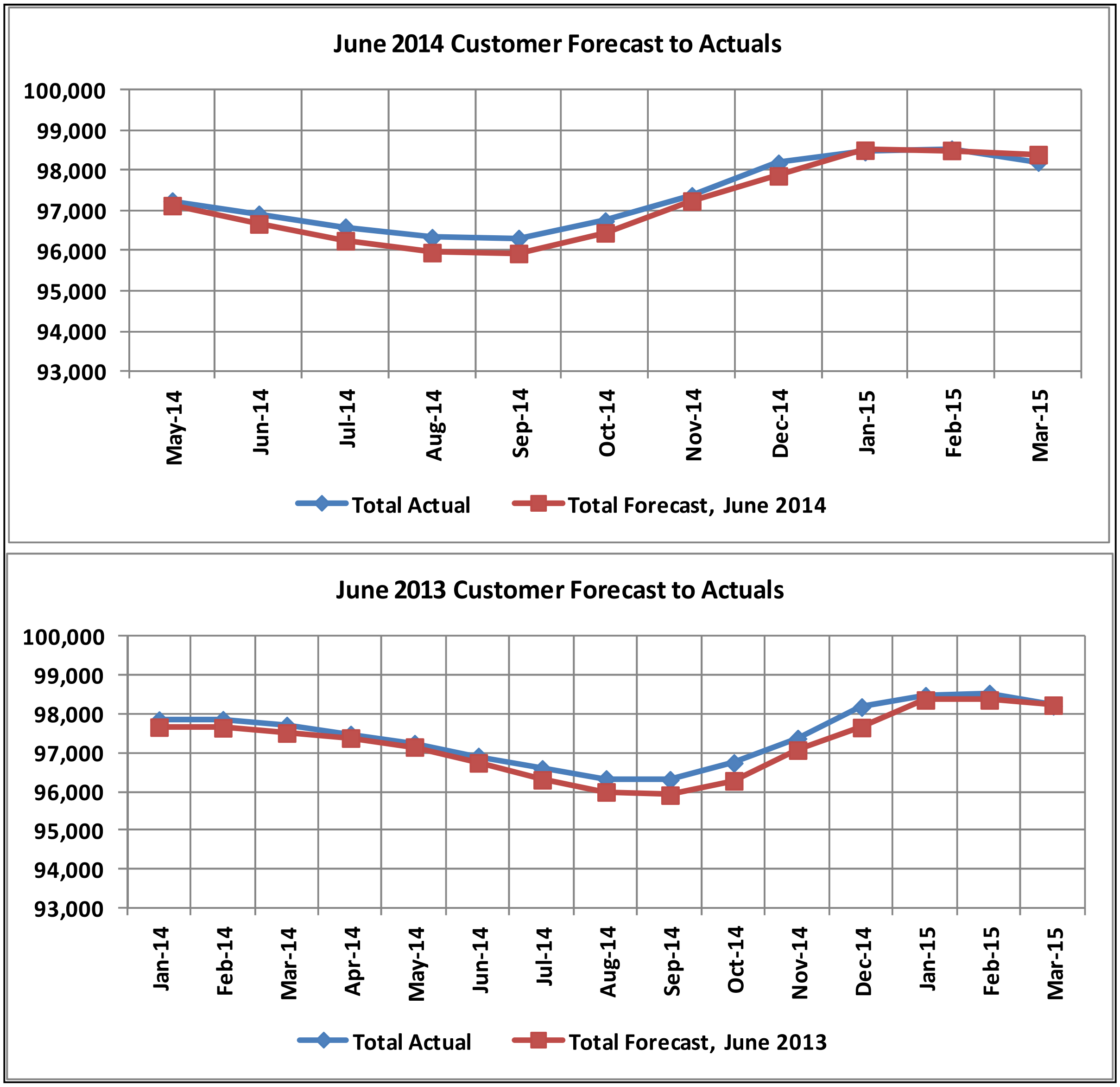
Q. How accurate has Avista's customer forecast been compared to actual customers?

A. The customer forecasts have been very accurate. Illustration No. 2 shows a comparison of actual and forecasted customers since the June 2014 (top graph) and June 2013 (bottom graph) forecasts. The June 2014 forecast is the most recent customer forecast. Customers reflect the sum of schedules 410, 420, 424, 440, 444, 447, and 456. The June 2014 graph starts in May 2014—the the first forecasted month—and ends in March 2015. The monthly percentage error between actual and forecast (i.e., actual/forecast – 1) averaged only 0.19 percent (an average of 180 customers) over 11 months. For the first quarter of 2015, the error averaged only -0.06 percent.[3] As an additional test of forecast accuracy, the bottom graph shows a comparison of actual and forecasted customers using the June 2013 forecast. The graph starts in January 2014 and ends in March 2015. The monthly percentage error between actual and forecast averaged 0.24 percent (an average of 232 customers) over 15 months. For the first quarter of 2015, the average error was only 0.09 percent.

[3] For the most recent month, March 2015, the forecasted number of customers for Schedule 410 was 86,834. The actual number of customers was 86,756 (0.1% below forecast). For Schedule 420, the forecasted level of customers was 11,412. The actual number of Schedule 420 customers was 11,312 (0.9% below forecast).

<u>Illustration No. 2:</u>

Comparison of 2014 and 2013 Customer Forecast to Actuals



<u>IV. USE-PER-CUSTOMER FORECAST</u>

Q. What is the methodology behind the use-per-customer ("UPC") forecast and what are the primary forecast drivers?

A. Similar to the customer forecast, the UPC forecast use standard time-series regression models based on historical UPC data. Following the customer forecasts, the UPC forecasts are generated for each schedule in each class for each of the four regions. The standard UPC forecast horizon is also five-years. The most important forecast driver is weather, as measured by heating degree days (HDD) relative to a 65 degree Fahrenheit base. In addition to HDD, seasonal "dummy variables" are frequently used to capture non-temperature-related seasonality. For the majority of schedules, the use of HDD and seasonal dummy variables accounts for the majority of historical UPC behavior.

For forecasting purposes, the Company assumes "average" or "normal" weather will hold over the forecast period. Starting in 2013, the Company moved to a 20-year moving average for the definition of normal weather. Prior to 2013, NOAA's standard 30-year average was used. This means, each year the definition of normal weather is updated by moving the 20-year average ahead one year. The reason for this changed is discussed below.

In addition to HDD and seasonal dummy variables, real (inflation adjusted) average annual price per therm is used as a forecast driver for the Medford, Roseburg, and Klamath Falls region's residential forecast. This price driver is lagged by one year reflecting that the lagged, and not current price per therm, has a negative impact on UPC. This implies that the price elasticity of demand in the short-run is close to zero. For the La Grande region, price is not used as a driver because the regression relationship between price and UPC is unstable, suggesting very little short- or long-run price elasticity.

Q. Why is a 20-year moving average used?

A. The choice of a 20-year moving average for defining normal weather reflects several factors. First, recent climate research from NASA's Goddard Institute for Space

Studies ("GISS"), in addition to an in-house analysis of weather in Avista's Spokane-Kootenai and Medford services area, shows a shift in temperature starting about 20-years ago. The GISS research shows that summer temperatures in the Northern Hemisphere have increased about 1^{o} F above the 1951-1980 reference period, and the increase started roughly 20 years ago in the 1981-1991 period.[4] The second factor is the volatility of the moving average as a function of the years used to calculate the average. Moving averages of 10 and 15 years showed considerably more year-to-year volatility than the 20 year average. Using a shorter moving average can obscure longer-term trends and lead to overly sharp changes in forecasted loads when the updated definition of normal weather is applied each year. Such volatile changes could cause excessive volatility in the revenue and earnings forecasts.

Q. How are prices forecasted for Medford, Roseburg, and Klamath 410 residential schedules?

A. The process for forecasting prices is a complicated multi-step process that uses a combination of national, state, and Company-level data. The primary internal sources are the Company's Rates and Natural Gas Supply Departments. The primary external data sources are the U.S. Department of Energy (the Energy Information Administration), the Chicago Mercantile Exchange, and Bureau of Labor Statistics. The final price forecast is arrived at through a combination of multiple regressions with adjustments made for the information provided by the Company's Rates and Natural Gas Supply Departments.

Q. How is U.S. Industrial Production forecasted for use in certain industrial schedules?

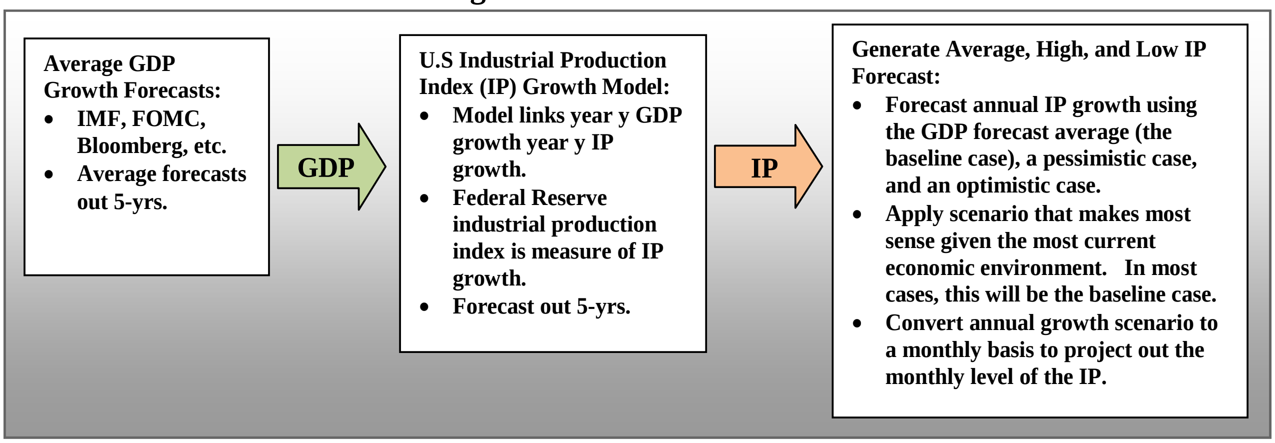
A. The same U.S. GDP forecast that underlies the population forecast (see

[4] See Hansen, J.; M. Sato; and R. Ruedy (2013). *Global Temperature Update Through 2012*, http://www.nasa.gov/topics/earth/features/2012-temps.html

Illustration No. 1) is used to forecast U.S. Industrial Production ("IP"). Illustration No. 3 below outlines this process, which relies on a regression model to convert forecasted U.S. GDP growth to an IP growth forecast. This method is used because of the historically high correlation between these two measures of output.

<u>Illustration No. 3:</u>

Forecasting Industrial Production Growth



Three different cases are estimated: the baseline case, the optimistic case, and the pessimistic case. Generally, the baseline case is used for the final forecast; however, the other cases are included as a cross-check just in case economic conditions warrant something other than the baseline. The optimistic and pessimistic cases are arrived at by using optimistic and pessimistic GDP growth forecasts. Finally, IP growth forecasts are converted to monthly growth rates so that monthly forecasts can be generated.

Q. What statistical measures do you use to judge the appropriateness of a regression model?

A. Regression based time-series models need to meet certain statistical criteria to produce reliable forecasts. These criteria are checked through a series of statistical "fit" tests automatically generated in SAS/ETS®: (1) Root-mean-square error, R-square, and similar tests; (2) error term autocorrelation tests; (3) error term Dickey-Fuller tests for stationarity; (4) tests for error term normality; and (5) graphical confirmation that forecasts are not sequentially out of alignment with recent historical behavior and the current economic environment. This latter test is important because a model can have good statistical fit tests and still produce forecasts that are not plausible given current economic conditions.

Q. Besides the economic drivers discussed above, do you consider any other variables that may influence your forecast?

A. Yes. I closely follow (1) actual and forecasted U.S. GDP growth and inflation; (2) Federal Reserve statements and guidance regarding interest rates; (3) federal and state fiscal policies; (4) county unemployment rates and employment growth by sector; (5) weekly residential building permits using the Construction Monitor service for Southwest Oregon; (6) monthly county residential building permits collected by the U.S. Census; (7) real wage and income growth; (8) regional press reports about economic activity; and (9) discussions with Avista's Oregon employees regarding economic conditions in Avista's Oregon operations area.

Q. Using the results of your modeling, what do you forecast UPC to be in the 2016 rate year?

A. Table No. 2 below provides the 2014 base year and 2016 test year UPC:

Table No. 2: UPC per Month

Year	Schedule 410	Schedule 420	Schedules 424, 440 & 444	Schedules 447 & 456
2014	46.3	194.5	5,911	90,359
2016	46.9	194.3	6,082	103,226
Annualized % Change	**0.6%**	**-0.1%**	**1.4%**	**7.1%**

For Residential Schedule 410, where weather and price are the two primary drivers, the modeling shows a only slight increase in UPC from the 2014 base year to the 2016 test year. For General Natural Gas Service Schedule 420, whose growth is highly dependent upon the growth in the number of Schedule 410 customers, UPC is forecasted to remain flat. Further, Large Sales customers served on Schedules 424, 440, and 444 were also forecasted to have generally flat growth in UPC. However, for the special contract and transportation rate schedules 447 and 456, overall UPC is forecasted to increase substantially over the two year time period. This growth is directly related to the general business cycle, and using the primary driver of US Industrial Production, my forecast shows an increase in UPC due to an overall ramp up of production.

V. LOAD FORECAST

Q. In general terms, what is the basic modeling methodology behind the load forecast?

A. As discussed earlier, Avista's natural gas load forecast is comprised of (1) a number of customer forecast and (2) a use-per-customer ("UPC") forecast. These are conducted for each rate schedule, and by customer class (i.e., residential, commercial, and industrial). The customer and UPC forecasts are completed on a monthly basis and extend out five years. For each rate schedule, customer and UPC forecasts are multiplied together in order to produce a monthly (billing month), five year load forecast.

The Company, however, cannot simply just use the results of multiplying UPC by the forecasted number of customers. The reason is because these values, UPC and number of customers, is on a billing month basis. This assumes that, for example, the load for March

2017 in my forecast is consumed and billed entirely within that month. In reality, some of the usage that is billed in March 2017 is from February 2017, and some of the usage consumed in March 2017 is not billed until April 2017. This is what is commonly referred to as "billed" and "unbilled". For the ultimate revenue forecast we need to incorporate unbilled usage.

To accomplish this, when the customer forecast for firm customers is complete, it is sent to the Natural Gas Supply Department for input into their SENDOUT® model. This model, which uses linear optimization, generates a system-wide forecast for firm load on a monthly calendar basis (reflecting billed and unbilled), as opposed to the billing month used in my load forecast.[5] While SENDOUT® can forecast firm load in the manner in which we need it, it does not forecast it by rate schedule. Therefore, the Company uses my firm system load forecast results to allocate SENDOUT®'s system firm load forecast by schedule.[6] By doing so, the allocated load forecast includes both billed and unbilled usage.

Load forecasts for interruptible and transportation customers come directly from my forecast and are input directly into the Company's revenue model. The revenue model converts the forecasts of firm load and interruptible/transportation load into a revenue forecast. In turn, the revenue forecast is used in the Company's earnings model to generate the earnings forecast.

Q. What are the final results of the overall load forecast?

A. The current customer forecast shows a continued modest growth in customers

[5] Load forecasts for interruptible and transportation customers that come directly from the customer and UPC forecasts are inputted directly into the Company's revenue model, as SENDOUT® does not forecast for those types of customers (non-firm).

[6] This is done by first taking my system firm load forecast for each state and converting the state's forecast to a load share forecast. In the case of Oregon, this is done by taking my monthly firm load forecast by schedule for Oregon and dividing it by my monthly system forecast for Oregon. This generates a five-year monthly share forecast for each Oregon schedule. This forecasted share is then multiplied to SENDOUT®'s Oregon system forecast to generate the forecasted firm load for each Oregon schedule.

in the Medford, Roseburg, Klamath Falls, and La Grande regions over the next five-years. This reflects the assumption that, following the Great Recession, the economic recovery in these regions will also continue at a modest pace. The UPC forecast continues to show a modest decline over the next five-years in UPC due largely to the assumption of gradually rising real residential prices. The combined influence of the customer and UPC forecasts means that total load growth, compared to pre-Great Recession growth, is expected to be modest over the next five-years.

Table No. 3 below provides a comparison of the change in total usage by rate schedule from the 2014 base year to the 2016 test year.

Table No. 3: Comparison of Change in Usage from 2014 to 2016

	Residential Service Schedule 410	General Service Schedule 420	Schedules 424, 440 and 444	Schedules 447 and 456	Total
2014 Normalized Usage	47,711,116	26,335,129	8,174,865	42,649,341	124,870,451
2016 Forecasted Usage	49,018,942	26,621,408	8,821,802	47,119,020	131,581,172
Percentage Change (2 Year)	**2.7%**	**1.1%**	**7.9%**	**10.5%**	**5.4%**

The combination of low customer growth and flat UPC for the Company's Schedules 410 and 420 results in a combined 2.2% increase in customer usage from the 2014 base year to the 2016 test year. While the Company's forecast shows a total overall increase in customer usage of 5.4% over the 2014 to 2016 two-year time period, only approximately 33% of the projected load increase is from sales customers (Schedules 410 – 444), with the other 67% coming from transportation and special contract customers (Schedules 447 and 456).

Q. Does the Company conduct a reasonableness check of its load forecast?

A. Yes, tests for reasonableness are a normal part of finalizing the load forecast. One test includes verifying that total annual load forecasts (my forecast and the SENDOUT®

model) are not materially different. Even though the models are applying a different methodology, both methods produce very similar forecasts on an annual basis. Should the forecasts differ materially, then a review of both methods is conducted to reconcile the differences. Another test is to compare the forecast against the latest regional data on economic growth. This is to verify that the customer and load forecasts are still reasonable given the assumptions used in the forecast and the most current information about the economy.

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

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DR. GRANT D. FORSYTH
Exhibit No. 701

Load Forecast Modeling Overview

1. Introduction

This exhibit covers four main areas. Section 2 provides information on weather forecast drivers, and how they are adjusted for the Company's billing period. Section 3 provides information on non-weather forecast drivers used in conjunction with autoregressive-integrated-moving average (ARIMA) models. Section 4 presents the use per customer and customer forecasting models using standard econometric notation. That section is organized around the four main regions in the Company's service territory: Medford, Roseburg, Klamath Falls, and La Grande. Section 4 also provides an overview of how SENDOUT® is used in conjunction with my forecast.

2. Weather Forecast Drivers

Degree days are based on NOAA data and are divided into heating degree days (HDD), quality heating degree days (QHDD), and cooling degree days (CDD). HDD reflect usage in the colder months; CDD reflects usage in the summer months; and QHDD reflect usage in the coldest winter months of December, January, February, and March. The baseline for calculating HDD and QHDD is 65 degree Fahrenheit.

Because of Avista's (AVA) billing lags, degree day data has to be adjusted as follows:

[2.1] $HDD_t^{AVA} = 0.5(HDD_t^{NOAA}) + 0.5(HDD_{t-1}^{NOAA})\ for\ month\ t = Jan, \ldots, Dec$

[2.2] $CDD_t^{AVA} = 0.5(CDD_t^{NOAA}) + 0.5(CDD_{t-1}^{NOAA})\ for\ month\ t = Jan, \ldots, Dec$

QHDD are calculated as:

[2.3] $QHDD_t^{AVA} = 0.5(HDD_t^{NOAA}) + 0.5(HDD_{t-1}^{NOAA})\ for\ month\ t = Jan\ and\ Feb$

[2.4] $QHDD_t^{AVA} = 0.5(HDD_t^{NOAA})\ for\ month\ t = Dec$

[2.5] $QHDD_t^{AVA} = 0.5(HDD_{t-1}^{NOAA})\ for\ month\ t = Mar\ and\ t - 1 = Feb$

[2.6] $QHDD_t^{AVA} = 0\ for\ t = Apr, \ldots, Nov$

Below, HDD_t^{AVA}, CDD_t^{AVA}, and $QHDD_t^{AVA}$, is referred to as Avista adjusted (AVA) data. Normal weather is defined as a 20-year moving average. All forecasts use the most recent 20-year moving average as normal weather going forward. This calculation is conducted for each of Avista's four Oregon regions: Medford, Roseburg, Klamath Falls, and La Grande. As can be seen in Section 4, degree days are often squared to take into account non-linear relationships between customer usage and weather.

3. Non-Weather Forecast Drivers

Non-weather drivers are energy price (RAP); U.S. Federal Reserve industrial production index (IP), non-weather seasonal dummies (SD); trend functions (T or the natural log, lnT);

and dummies for outliers (OL) and periods of possible structural change (SC). The SC dummies control for periods where there are deviations from long-run behavior trends. This could be due to unique economic shocks and/or the sudden in- or out-migration of customers that temporarily changes the series behavior. Household Income does not appear as an explanatory variable in any of the residential models because it was found not to be statistically significant. In the case of Oregon, RAP occurs only the residential schedules and is lagged one year. This means the model indicates that it takes one year for a price change to impact behavior.

Pure ARIMA and ARIMA "transfer function" models are frequently used. In these cases, the error structure is expressed as $\epsilon_{t,y}$ = ARIMA$\epsilon_{t,y}$(p,d,q)(p_k,d_k,q_k)$_k$. The term p is the autoregressive (AR) order, d is the differencing order, and q is the moving average (MA) order. The term p_k is the order of seasonal AR terms, d_k is the order of seasonal differencing, and q_k is the seasonal order of MA terms. The seasonal values are related to "k," which is the frequency of the data. With the current data set, k = 12 for both use per customer (THM/C, THM = therms) and customers (C) for each schedule.

For the main residential and commercial schedules, the modeling approach needs to take into account that historical customer growth between the main schedules is highly, positively correlated. To ensure this relationship is reflected in the customer and load forecasts, the customer models for the 420 commercial schedules use 410 residential customers as a forecast driver—except for Roseburg. In the case of Roseburg, the correlation between residential and commercial growth is weak. This means, except for Roseburg, the final customer forecast for residential schedule 410 are used as a variable to forecast commercial customers. In turn, the 410 customer forecasts are driven by population forecasts. Population growth is factored in by adjusting the baseline residential 410 customer forecasts (equations [4.53], [4.75], [4.97], and [4.116]) by the forecasted population growth rate for that region. If a region's baseline customer forecast is in line with population forecast, then no adjustment is made.

Note that dates on the some of the dummy variables are followed by "↑," which means "going forward in time." For example, "Jan 2009↑=1" means, "From January 2009 forward the dummy variable equals 1." Also note that t = month and y = year. For example $THM/C_{t,y,MED410.r}$ should be read as, "Therms per customer in month t, of year y, for Medford residential (r) schedule 410. For industrial (i) and commercial (c) similar notation is used.

Not all schedules require an ARIMA based model. In some schedules, simple regression and smoothing methods are used because they offer the best fit for usage that is periodic and/or irregular; is in a long-run, but steady, decline; and/or is seasonal but not weather related.

Total THM for each schedule is arrived at by multiplying customer forecasts by use per customer forecasts. In some cases, these forecasts are adjusted to reflect information that cannot be accounted for a model based on historical data.

4. Use Per Customer and Customer Forecast Models by Region

This section presents the use per customer (UPC) and customer forecast models. The total load for a given schedule is derived by multiplying the UPC forecast by the customer forecast. The system load is then generated by summing across all the forecasts by schedule. A discussion of how SENDOUT® is used concludes this section.

4a. *Medford, OR Forecasting Models*

The forecasting models for the Medford region (Jackson County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, Use Per Customer:

[4.51] $THM/C_{t,y,MED410.r} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \lambda RAP_{t,y-1,OR410} + \gamma_1 lnT + + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{May\ 2011=1} + ARIMA\epsilon_{t,y}\ (12,0,0)(0,0,0)_{12}\ for\ y = 2006 \uparrow$

[4.52] $THM/C_{t,y,MED420.r} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \omega_{OL} D_{Dec\ 2009-Feb\ 2010=1} + \omega_{OL} D_{Jan\ 2011=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}$

Residential Sector, Customers:

[4.53]
$C_{t,y,MED410.r} = \alpha_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{May\ 2013=1} + \omega_{OL} D_{Oct\ 2013=1} + ARIMA\epsilon_{t,y}\ (5,1,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

[4.54] $C_{t,y,MED420.r} = C_{t,y-1} + 1\ (add\ approximately\ one\ customer\ per\ year)$

Commercial Sector, Use Per Customer:

[4.55] $THM/C_{t,y,MED420.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Nov\ 2008\uparrow=1} + \omega_{OL} D_{Mar\ 2010=1} + \omega_{OL} D_{April\ 2010=1} + ARIMA\epsilon_{t,y}\ (11,0,0)(0,0,0)_{12}\ for\ 2007 \uparrow$

[4.56]
$THM/C_{t,y,MED424.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \epsilon_{t,y}\ for\ t,y\ July\ 2010\ forward$

[4.57] $THM/C_{t,y,MED444.c} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}$

[4.58] $THM/C_{t,y,MED440.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = September\ 2009 \uparrow$

[4.59]
$THM/C_{t,y,MED456.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + ARIMA\epsilon_{t,y}\ (4,0,0)(0,0,0)_{12}\ for\ t,y = August\ 2010 \uparrow$

Commercial Sector, Customers:

[4.60] $C_{t,y,MED420.c} = \alpha_0 + \alpha_1 C_{t,y,MED410.r} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (3,1,0)(1,0,0)_{12}\ for\ 2007 \uparrow$

[4.61] $C_{t,y,MED424.c} = C_{t,y-1} + 1\ (add\ approximately\ one\ customer\ per\ year)$

[4.62] $C_{t,y,MED444.c} = \; 1\, if\ (THM/C_{t,y})_{MED,440.c} > 0$

[4.63] $C_{t,y,MED440.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.64] $C_{t,y,MED456.c} = \; C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$

Industrial Sector, Use Per Customer:

[4.65] $THM/C_{t,y,MED420.i} = \; \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 \; + \delta_1 IP_{t,y} + \omega_{OL} D_{March\ 2011\ =1} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[4.66]
$THM/C_{t,y,MED424.i} = \; \alpha_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Aug\ 2012\ =1} + \omega_{OL} D_{Sept\ 2012\ =1} \; + ARIMA\epsilon_{t,y}\ (2,0,0)(0,0,0)_{12}\ \; for \; = 2010 \uparrow$

[4.67] $THM/C_{t,y,MED440.i} = \; \alpha_0 \; + \boldsymbol{\omega_{SD} D_{t,y}} \; + \omega_{SC} D_{May\ 2011\uparrow =1} + ARIMA\epsilon_{t,y}\ (7,1,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[4.68]
$THM/C_{t,y,MED456.i} = \; \alpha_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \; \omega_{OL} D_{Jan\ 2008\ =1} + \; \omega_{OL} D_{Sept\ 2008\ =1} \; + \; ARIMA\epsilon_{t,y}\ (3,0,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

Industrial Sector, Customers:

[4.69] $C_{t,y,MED420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.70] $C_{t,y,MED424.i} = \; C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$

[4.71] $C_{t,y,MED440.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.72] $C_{t,y,MED456.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

4b. Roseburg, OR Forecasting Models

The forecasting models for the Roseburg region (Douglas County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

[4.73] $THM/C_{t,y,ROS410.r} = \; \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 \;\; + \lambda RAP_{t,y-1,OR410} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 2011=1} + \; \omega_{OL} D_{Feb\ 2012=1} + \; \gamma_1 lnT + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}$

[4.74] $THM/C_{t,y,ROS420.r} = \; \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Jan\ 2013=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = March\ 2010 \uparrow$

Residential Sector, Customers:

[4.75] $C_{t,y,ROS410.r} = \;\; \varphi_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 2007\ =1} + \omega_{OL} D_{Dec\ 2007\ =1} + \omega_{OL} D_{Feb\ 2008\ =1} + \omega_{OL} D_{Sept\ 2008\ =1} +$

$\omega_{OL} D_{Nov\ 2009=1} + ARIMA\epsilon_{t,y}\ (4,1,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

[4.76] $C_{t,y,ROS420.r} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

Commercial Sector, Use Per Customer:

[4.77]
$THM/C_{t,y,ROS420.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (8,0,0)(0,0,0)_{12}$

[4.78]
$THM/C_{t,y,ROS424.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (6,0,0)(0,0,0)_{12}\ for\ t,y = August\ 2009 \uparrow$

[4.79] $THM/C_{t,y,ROS440.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \gamma_1 lnT + \omega_{OL} D_{Oct\ 2009=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Nov\ 2010=1} + \omega_{OL} D_{May\ 2013=1} + \omega_{OL} D_{Jun\ 2013=1} + \omega_{OL} D_{Oct\ 2013=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = May\ 2007 \uparrow$

[4.80] $THM/C_{t,y,ROS456.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + ARIMA\epsilon_{t,y}\ (2,0,0)(0,0,0)_{12}\ for\ t,y = March\ 2010 \uparrow$

Commercial Sector, Customers:

[4.81] $C_{t,y,ROS420.c} = \varphi_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_1 T + \omega_{OL} D_{Jan\ 2008=1} + \omega_{OL} D_{Mar\ 2009=1} + ARIMA\epsilon_{t,y}\ (4,1,0)(0,0,0)_{12}$

[4.82] $C_{t,y,ROS424.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.83] $C_{t,y,ROS440.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.84] $C_{t,y,ROS456.c} = C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$

Industrial Sector, Use Per Customer:

[4.85]
$THM/C_{t,y,ROS420.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Aug\ 2010-Dec\ 2011=1} + ARIMA\epsilon_{t,y}\ (3,1,0)(0,0,0)_{12}\ for\ t,y = Jan\ 2010 \uparrow$

[4.86] $THM/C_{t,y,ROS424.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Aug\ 2007=1} + \omega_{SC} D_{Jan\ 2008-Jul\ 2009=1} + ARIMA\epsilon_{t,y}\ (5,0,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

[4.87]
$THM/C_{t,y,ROS440.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2012=1} + \omega_{OL} D_{Aug\ 2012=1} + \omega_{OL} D_{Jan\ 2014=1} + ARIMA\epsilon_{t,y}\ (4,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[4.88] $THM_{t,y,ROS447m.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2008=1} + ARIMA\epsilon_{t,y}\ (4,1,0)(0,0,0)_{12}\ for\ t,y = July\ 2008 \uparrow$

[4.89]
$THM_{t,y,ROS447r.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{OL} D_{Apr\ 2010=1} + \omega_{OL} D_{Feb\ 2013=1} + ARIMA\epsilon_{t,y}\ (5,1,0)(0,0,0)_{12}\ for\ t,y = April\ 2010 \uparrow$

[4.90] $THM/C_{t,y,ROS456.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{July\ 2013=1} + ARIMA\epsilon_{t,y}\ (0,1,0)(1,0,0)_{12}\ for\ y = 2008 \uparrow$

Industrial Sector, Customers:

[4.91] $C_{t,y,ROS420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.92] $C_{t,y,ROS424.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.93] $C_{t,y,ROS440.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.94] $C_{t,y,ROS456.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

4c. Klamath Falls, OR Forecasting Models

The forecasting models for the Klamath Falls region (Klamath County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, Use Per Customer:

[4.95]
$THM/C_{t,y,KLM410.r} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \lambda RAP_{t,y-1,OR410} + \omega_{OL} D_{Apr\ 2007=1}\ \omega_{OL} D_{Dec\ 2008=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Feb\ 2011=1} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (10,0,0)(0,0,0)_{12}$

[4.96] $THM/C_{t,y,KLM420.r} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \epsilon_{t,y}\ \ for\ \ t,y = July\ 2011\ \uparrow$ (potential non-white noise error and non-stationarity due to a short time-series)

Residential Sector, Customers:

[4.97] $C_{t,y,KLM410.r} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (6,1,0)(0,0,0)_{12}\ for\ \ y = 2007 \uparrow$

[4.98] $C_{t,y,KLM420.r} = C_{t,y-2} + 1\ (add\ one\ customer\ every\ 2\ years\ from\ current\ year)$

Commercial Sector, Use Per Customer:

[4.99] $THM/C_{t,y,KLM420.c} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Aug\ 2009-July\ 2012=1} + \omega_{SC} D_{Aug\ 2012\uparrow=1} + ARIMA\epsilon_{t,y}\ (9,0,0)(0,0,0)_{12}\ for\ y = 2009 \uparrow$

[4.100]
$THM/C_{t,y,KLM424.c} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{OL} D_{Jan\ 2011=1} + ARIMA\epsilon_{t,y}\ (10,0,0)(0,0,0)_{12}\ for\ y = 2010 \uparrow$

[4.101] $THM/C_{t,y,KLM440.c} = \frac{1}{N}\sum_{j=1}^{N}(THM/C_{t-j})\ \ for\ t,y = Feburary\ 2007$

Commercial Sector, Customers:

[4.102] $C_{t,y,KLM420.c} = \beta_0 + \beta_1 C_{t,y,KLM410.r} + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_1 lnT + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

[4.103] $C_{t,y,KLM424.c} = C_{t,y-2} + 1\ (add\ one\ customer\ every\ 2\ years\ from\ current\ customer\ level)$

[4.104] $C_{t,y,KLM440.c} = \frac{1}{N}\sum_{j=1}^{N} C_{t-j}\ \ for\ N = total\ available\ months\ of\ data\ history\ since\ 2007$

Industrial Sector, Use Per Customer:

[4.105] $THM/C_{t,y,KLM420.i} = \beta_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Aug\ 2008=1} + \omega_{OL} D_{Jan\ 2010-Feb\ 2010=1} + ARIMA\epsilon_{t,y}\ (12,0,0)(0,0,0)_{12}\ for\ t,y = June\ 2008 \uparrow$

[4.106] $THM/C_{t,y,KLM424.i} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (2,0,0)(0,0,0)_{12}\ for\ t,y = August\ 2009 \uparrow$

[4.107] $THM_{t,y,KLM440.i} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Sep\ 2008=1} + \omega_{OL} D_{Sep\ 2009=1} + \omega_{OL} D_{Oct\ 2010=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{Sept\ 2013=1} + \omega_{OL} D_{Oct\ 2013=1} + \epsilon_{t,y}\ for\ y = 2008 \uparrow$

[4.108] $THM_{t,y,KLM447w.i} = \beta_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{Jul\ 2012=1} + ARIMA\epsilon_{t,y}\ (10,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[4.109] $THM/C_{t,y,KLM456.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{SC} D_{Nov\ 2013\uparrow=1} + \omega_{OL} D_{May\ 2012=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

Industrial Sector, Customers:

[4.110] $C_{t,y,KLM420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.111] $C_{t,y,KLM424.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.112] $C_{t,y,KLM440.i} = 1\ if\ (THM/C_{t,y})_{KLM,440.i} > 0$

[4.113] $C_{t,y,KLM456.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

4d. La Grande, OR Forecasting Models

The forecasting models for the La Grande region (Union County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, Use Per Customer:

[4.114] $THM/C_{t,y,LaG410.r} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \lambda RAP_{t,y-1,OR410} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2007=1} + \omega_{OL} D_{Jun\ 2011=1} + ARIMA\epsilon_{t,y}\ (11,0,0)(0,0,0)_{12}$

[4.115] $THM/C_{t,y,LaG420.r} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2012=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = June\ 2010\ \uparrow$

Residential Sector, Customers:

[4.116] $C_{t,y,LaG410.r} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (6,1,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

[4.117] $C_{t,y,LaG420.r} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

Commercial Sector, Use Per Customer:

[4.118] $THM/C_{t,y,LaG420.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \omega_{SC} D_{Aug\ 2012\uparrow=1} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (3,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[4.119] $THM/C_{t,y,LaG424.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2008-Nov\ 2008=1} + \omega_{OL} D_{Jan\ 2008=1} + \omega_{OL} D_{Sept\ 2010=1} + \omega_{OL} D_{Jan\ 2011=1} + ARIMA\epsilon_{t,y}\ (3,0,0)(0,0,0)_{12}\ for\ 2008 \uparrow$

[4.120] $THM/C_{t,y,LaG444.c} = \frac{1}{N}\sum_{j=1}^{N}(THM/C_{t,y-j})\ for\ t = September\ or\ October\ for\ y = 2011 \uparrow$

[4.121] $THM/C_{t,y,LaG440.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Sept\ 2013=1} + ARIMA\epsilon_{t,y}\ (3,0,0)(0,0,0)_{12}\ for\ t,y = Sept\ 2009 \uparrow$

[4.122] $THM/C_{t,y,LaG456.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

Commercial Sector, Customers:

[4.123] $C_{t,y,LaG420.c} = \theta_0 + \theta_1 C_{t,y,LaG410.r} + \omega_{OL} D_{Dec\ 2008=1} + \omega_{OL} D_{Mar\ 2011=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[4.124] $C_{t,y,LaG424.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.125] $C_{t,y,LaG444.c} = 1\ if\ (THM/C_{t,y})_{Lag,444.c} > 0$

[4.126] $C_{t,y,LaG440.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[4.127] $C_{t,y,LaG456.c} = C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$

Industrial Sector, Use Per Customer:

[4.128] $THM/C_{t,y,LaG440.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Oct\ 2008=1} + \omega_{OL} D_{Jan\ 2010=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{Feb\ 2013=1} + \omega_{OL} D_{Nov\ 2013=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}$

[4.129]
$$THM/C_{t,y,LaG444.i} = \theta_0 + \boldsymbol{\omega_{SD}} \boldsymbol{D_{t,y}} + \omega_{OL} D_{Oct\ 2007\ =1} + \omega_{OL} D_{Sept\ 2008\ =1} + \omega_{OL} D_{Nov\ 2010\ =1} + \omega_{OL} D_{Jan\ 2011\ =1} + + \omega_{OL} D_{July\ 2012\ =1} + \omega_{OL} D_{Sept\ 2012\ =1} + \omega_{OL} D_{April\ 2013\ =1} + ARIMA \epsilon_{t,y} (2,0,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$$

[4.130] $$THM/C_{t,y,LaG456.i} = \theta_0 + \boldsymbol{\omega_{SD}} \boldsymbol{D}_{t,y} + \omega_{SC} D_{Jan\ 2014\uparrow =1} + ARIMA \epsilon_{t,y} (1,1,0)(0,0,0)_{12}\ for\ t,y = July\ 2008 \uparrow$$

Industrial Sector, Customers:

[4.131] $$C_{t,y,LaG440.i} = \theta_0 + \boldsymbol{\omega_{SD}} \boldsymbol{D}_{t,y} + \omega_{OL} D_{Jan\ 2010\ =1} + \epsilon_{t,y}\ for\ y = 2007 \uparrow$$

[4.132] $$C_{t,y,LaG444.i} = \theta_0 + \boldsymbol{\omega_{SD}} \boldsymbol{D_{t,y}} + \omega_{OL} D_{Jan\ 2010\ =1} + \omega_{OL} D_{Aug\ 2011\ =1} + ARIMA \epsilon_{t,y} (3,0,0)(0,0,0)_{12}$$

[4.133] $$C_{t,y,LaG456.i} = \frac{1}{12} \Sigma_{j=1}^{12} C_{t-j}$$

4e. The Integration of SENDOUT®

As will be discussed below, my forecast is used in conjunction with the Company's Gas Supply forecast model known as SENDOUT®. SENDOUT® is used to aid the Company's gas purchase decisions. When my forecast is complete, the firm customer forecasts are sent to the Gas Supply Department (GSD) where they are used in the SENDOUT® model to generate a system wide forecast for firm load. SENDOUT® models load using linear optimization and generates forecasts on a monthly calendar basis, as opposed to the billing month used in my forecast. SENDOUT®'s forecast is used so that firm unbilled usage can be incorporated into the revenue forecast.

My firm load forecast is used to allocate the SENDOUT® forecast by schedule. This is done because SENDOUT®, which includes unbilled usage, cannot generate load forecasts by schedule, which is also required for the Company's revenue model. Here, unbilled usage is defined as usage registered on a meter but not yet billed to the customer. This occurs because billed usage is not on a calendar month. However, to appropriately book revenue, unbilled usage must also be estimated. Load forecasts for transport customers come directly from my model and are inputted directly into the Company's revenue model. The revenue model converts the forecasts of firm load (the combined forecasts of my model and SENDOUT®) and transport load (my forecasts only) into a revenue forecast. In turn, the revenue forecast is used in the Company's earnings model to generate the earnings forecast.

Tests for reasonableness are a normal part of finalizing the load forecast. One test includes verifying that total annual load forecasts from my model and SENDOUT® are not materially different. Even though the models are applying a different methodology, <u>both methods produce very similar forecasts an annual basis.</u> Should the forecasts differ materially, than a review of both methods is conducted to reconcile the differences.

The allocation of SENDOUT®'s forecast is based on the following for WA-ID:

[4.134] $$L_{t,y,k,s}^{F} = \left[L_{GS,t,y}^{F} \cdot \alpha_{GF,t,y,k}^{F}\right] \cdot \theta_{GF,t,y,j,s}^{F}\ \ for\ k = WA\ or\ ID$$

Here $L^F_{t,y,k,s}$ is the final forecast (F) in month t in year y for firm schedule s in state k (k = WA or ID) that goes into the revenue model; $L^F_{GS,t,y}$ is the system-wide forecast for WA-ID-OR generated from Gas Supply's (GS) SENDOUT® model in month t in year y ; $\alpha^F_{GF,t,y,k}$ is the share of my forecast (GF) forecast contributed in month t in year y for state k; and $\theta^F_{GF,t,y,k,s}$ is the share of my forecast contributed in month t in year y for state k for firm schedule s. From [4.134], the expression in brackets, $\left[L^F_{GS,t,y} \cdot \alpha^F_{GF,t,y,k}\right]$, is the firm load forecast for state k. Therefore, multiplying by $\theta^F_{GF,t,y,k,s}$ generates the forecast for schedule s in state j for the corresponding month and year.

More formally, my allocation values α and θ are defined as follows:

[4.135] $\alpha^F_{GF,t,y,k} \equiv \frac{L^F_{GF,t,y,k}}{L^F_{GF,t,y}}\ for\ k = WA\ or\ ID$

[4.136] $\theta^F_{GF,t,y,s} \equiv \frac{L^F_{GF,t,y,k,s}}{L^F_{GF,t,y,k}}\ for\ k = WA\ or\ ID$

For [7.135], $L^F_{GF,t,y,j}$ is my firm forecast for state j and $L^F_{GF,t,y}$ is my system-wide firm forecast for WA-ID. For [7.136], $L^F_{GF,t,y,k,s}$ is FP&A's firm forecast for schedule s and $L^F_{GF,t,y,k}$ is FP&A's firm forecast for state j.

For OR, the process similar, but no state allocation is required because SENDOUT® can generate stand-alone system forecast for OR only:

[4.137] $L^F_{t,y,OR,s} = L^F_{GS,t,y,OR} \cdot \theta^F_{GF,t,y,OR,s}$

[4.138] $\theta^F_{GF,t,y,s} \equiv \frac{L^F_{GF,t,y,OR,s}}{L^F_{GF,t,y,OR}}$

In [4.138] the interpretation of θ is the same as [7.136]. The method shown in [4.134] and [4.137] ensures that unbilled usage is included in the revenue forecast.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF JOSEPH D. MILLER
REPRESENTING AVISTA CORPORATION

Long-Run Incremental Cost of Service Study

I. INTRODUCTION

Q. Would you please state your name, business address and present position with Avista Corporation?

A. My name is Joseph D. Miller. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your responsibilities?

A. I am responsible for preparing data for and maintaining the regulatory natural gas cost of service models for the Company. I also provide support in the preparation of revenue analysis, rate spread and rate design, and miscellaneous other duties as required.

Q. Would you please describe your educational background and professional experience?

A. I am a 1999 graduate of Portland State University with a Bachelors degree in Business Administration, majoring in Accounting. In 2005, I graduated from Gonzaga University with a Masters degree in Business Administration. I joined the Company in March 2008, after spending eight years in both the public and private accounting sector. I started with Avista as a Natural Gas Accounting Analyst in the Company's Resource Accounting department. In January 2009, I joined the State and Federal Regulation Department as a Regulatory Analyst. My primary responsibility was coordinating discovery for the Company's general rate case filings. In my current role as a Senior Regulatory Analyst, I am responsible for the Company's natural gas cost of service studies in all jurisdictions, among other things.

Q. Would you please briefly summarize your testimony?

A. My testimony presents the natural gas cost of service study prepared for this filing. The results of the long-run incremental cost study indicate that at current rates, on a relative margin-to-cost basis, both residential customers and small commercial customers are paying less than their relative cost of service, while interruptible, large general, seasonal, and transportation customer groups exceed their relative cost of service to varying degrees. Company witness Mr. Ehrbar uses the results of the study as a guide to spread the proposed increase by service schedule.

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

A. Yes. I am sponsoring Exhibit No. 801, which is the Company's long-run incremental cost "LRIC" of service study, and Exhibit No. 802, which shows the functional component classification of the Company's proposed revenue requirement in this case.

Q. Were these exhibits prepared by you?

A. Yes.

II. LONG-RUN INCREMENTAL COST OF SERVICE STUDY

Q. What is a long-run incremental cost of service study and what is its purpose?

A. A long-run incremental cost of service study is an engineering-economic study which estimates the incremental annual cost of providing natural gas service to customers segregated into groups by rate schedule. When applied to current results of operations, the study indicates the adequacy of current rates compared to costs. The study results are used as one of the guidelines in determining the appropriate rate spread among rate schedules.

Q. Has the Company made any changes in LRIC methodology from its

prior base case methodology as proposed in Docket No. UG-284?

A. Yes. The Company agreed to make three changes to the LRIC study per the Settlement Agreement approved by the Commission in Docket No. UG-284. The agreed-upon changes per the Settlement Agreement, which were incorporated into this LRIC study, are as follows:

- Gas Planning will be allocated on a volumetric basis rather than on a customer-count basis.
- Core main costs, estimated on a LRIC/as-new basis, will be defined as total main costs minus main extension costs.
- Storage investment will be allocated on the basis of January sales rather than annual sales.

In addition, gas commodity costs, previously shown as an equal and offsetting amount in both revenue and expenses, have been removed from the study.

Q. What are the elements of the LRIC study?

A. The elements of the LRIC study include both incremental plant investment, and incremental operating and maintenance expenses. All of the information is accumulated in terms of cost-per-customer for an average or typical customer on each rate schedule and then summarized to represent the long-run incremental cost of the 2016 total pro forma customers and therms.

<u>Incremental Plant Investment Costs</u>

Q. What is included in incremental plant investment?

A. Incremental plant investment is segregated into three separate categories which are summarized below and discussed in further detail later in my testimony.

<u>New-Customer-Related Plant Investment:</u>

- Natural gas main extension to reach the customer;
- Service line to connect the customer to the main;
- Metering equipment at the customer's premises;

<u>System-Main-Related Plant Investment:</u>

- Long-run incremental <u>capacity</u> and <u>commodity</u> system main replacement investment;

<u>Underground Storage Plant Investment</u>

- Oregon's share of the Company's investment in underground storage facilities.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit No. 801 page 2 shows the calculation of the 2016 cost-per-customer of the various investment costs included in this study. System core main investments have been categorized into capacity or commodity unit costs.

Q. How are new customer related plant investments quantified in this study?

A. Typical natural gas main extensions are quantified in terms of the size and length of pipe recently provided for customers, multiplied by recent costs for each pipe size. A summary of recent Oregon project work orders was used to identify the average length and typical size of pipe to serve different residential and small commercial customers. Interruptible, special contract and transportation customers that have not had recent installations were individually examined to determine average current cost of pipe that is dedicated to them. For large general service customers on Schedule 424, a random sample comprising approximately 30% of the population was selected. Using the Company's facilities mapping system and the in-service date of the mains, the length and size of apparent line extensions associated with the randomly selected customers were identified and current costs applied to determine the sample line extension cost per customer for this group. The resulting values were also used for the seasonal customers on Schedule 444.

Service lines were quantified by the size of pipe typically needed for the type of customer. For large general service, interruptible, special contract, and transportation customers, the sample analysis and identified dedicated pipe were used to determine average current cost, similar to the main extension cost assignment.

Metering equipment was quantified by a weighted average current meter cost per customer. The weighted average captures the actual equipment types in service on each rate schedule priced at the 2014 average installed cost.

Q. You stated that system main related plant investment costs were simplified into capacity-related and commodity-related investments. Would you please explain what is included in these categories?

A. Yes. Long-run replacement cost was estimated by computing the current cost of all Oregon mains in service at December 31, 2014 by size and type. The current cost already accounted for by customer main extensions were deducted to determine remaining system replacement investment. The remaining value was segregated into capacity versus commodity by the 2014 peak and average ratio. The peak and average ratio reflects a balance between the way the system is designed (to meet peak demand) and the way it is utilized on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions). The capacity portion was then divided by estimated Oregon total design day usage and the commodity portion was divided by annual therms.

Q. How was the 2016 incremental capacity-related investment per customer quantified?

A. The Investment-per-Design-Day therm for the capacity-related portion of system replacement was divided by days in the year to arrive at a 100% load factor cost per therm shown on line 13 of page 2 of Exhibit No. 801. This cost per therm has been adjusted for each rate schedule, based on the average estimated design day load factor for customers served under the schedule. Customers' design day load characteristics are the primary criteria associated with system capacity planning. The rate schedule cost per therm is then applied to average annual consumption per customer to get capacity main investment per customer for each schedule.

Q. How was the 2016 incremental commodity-related main investment per customer quantified?

A. The investment-per-therm for the commodity-related portion of system replacement is multiplied by the average annual consumption per customer to get the commodity-related main investment per customer for each schedule.

Q. How was underground storage plant investment assigned?

A. The Oregon jurisdictional underground storage plant balance at December 31, 2014 was used to represent investment in underground storage facilities. The assignment of costs associated with Oregon's share of the Jackson Prairie Storage facility recognizes that storage provides benefits to customers both through the mitigation of natural gas commodity costs and pipeline balancing. The assignment related to the Jackson Prairie Storage facility was split based on an 87% sales commodity and 13% throughput (balancing) basis. This relationship has been utilized in this cost study by determining the cost-per-therm based on total throughput of 13% of the investment, and the cost-per-therm based on January sales volumes of the remaining 87% of the investment. These unit costs are then multiplied by the average-use-per customer to determine the investment-per-customer for each schedule.

Q. Exhibit No. 801 page 2 shows a "levelized plant cost factor" for each investment. What is the purpose of this factor?

A. The levelized plant cost factor is an annual carrying charge applied to plant investments. There is a different factor for services, meters, mains and underground storage based on different estimated lives.

Q. How are the levelized plant cost factors determined?

A. A "revenue requirement model" is used to determine the levelized revenue requirement (annual cost) associated with incremental plant over the estimated life of the asset. The model accounts for all costs and expenses associated with owning and maintaining the asset.

<u>Operating Expenses</u>

Q. What is included in gas supply and customer service related incremental operating and maintenance expenses?

A. This category captures the current costs associated with the gas supply department, meter reading, and billing customers.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit No. 801 page 3 itemizes the various operating and maintenance expenses included in this study.

Q. Please explain the responsibilities of the Gas Supply Department.

A. The Gas Supply Department is responsible for acquiring all natural gas supplies in order to serve the company's natural gas requirements. This includes the development of natural gas purchasing plans, scheduling, Integrated Resource plans, asset optimization strategies, and the management of gas costs, and the management of shared projects (such as Jackson Prairie). For purposes of this LRIC study, the Gas Supply Department has been segregated between the employees who are responsible for the natural gas scheduling function and all other employees (non-scheduling).

Q. Please explain the items shown on Exhibit No. 801 page 3.

A. The Gas Supply Department schedulers schedule and track all the natural gas being delivered at all delivery points on the system, including the natural gas owned by transportation customers. The majority of their time is spent for the benefit of core customers, however, transportation customers require individual attention. A proportion of their time devoted to providing services for transportation versus core customers was applied to the scheduler's hours charged to FERC Account 813 "Other Gas Expenses" during 2014, resulting in an estimate of the annual hours necessary for these services. The annual hours were then divided by the number of therms used to arrive at the hours per therm shown on page 3, line 1.

The majority of time for the remaining Gas Supply Department employees (non-scheduling), is also spent for the benefit of core customers, however, a small portion of their time is dedicated to the needs of transportation customers. The proportion of time devoted to providing services for transportation versus core customers was applied to the Gas Supply Department (non-scheduling) hours charged to FERC Account 813 "Other Gas Expenses" during 2014. The long-run cost of the Gas Supply Department (non-scheduling) was estimated by dividing the hours charged to FERC Account 813 "Other Gas Expenses" during the test year by the number of therms to arrive at the annual hours per therm shown on page 3, line 4.

The total hours charged to meter reading in 2014 were divided by the number of customers to determine the annual hours per customer spent on meter reading.

All of these labor hour estimates are then priced at the average direct labor charges per hour during 2014 to estimate the incremental cost per customer.

Finally, billing cost per customer has been estimated from the average annual cost per customer the Company has experienced in the Oregon service territory over the last five years.

<u>Cost of Gas Commodity</u>

Q. Are natural gas commodity costs included in the LRIC study?

A. No. All revenue and expenses associated with the cost of gas, Schedule 461, have been removed from the Company's filing.

<u>Results Analysis</u>

Q. What is shown on Exhibit No. 801, Page 1 entitled "Result Summary"?

A. The first three lines present the pro forma rate year usage and customer statistics relevant to the study. The next section, beginning on line 5 and ending on line 16, shows the pro forma rate year incremental costs for each component in the study. All items include revenue related expenses either through an after the fact gross up or embedded in the carrying charge on investment costs. The Long Run Incremental Distribution Cost on Line 17 is the sum of all the components included in the study. Beginning on line 18 the study brings in the Company revenue requirement segregated into components comparable with the LRIC components shown above. Each component cost is then assigned to the rate schedules based on the LRIC results for the equivalent component. Once all of the components have been assigned, the results for each schedule are summed to produce the LRIC Based Target Margin on line 25. Following this are the resulting Current-Margin-to-Target-Margin ratios stated both in the absolute (Line 26) and on a relative basis (Line 27). LRIC Based Target Margin results in an Oregon Total margin-to-cost ratio (shown on line 26) of 0.86. The Component LRIC Target Increase by Schedule, on line 28, represents the distribution margin revenue (including the proposed increase) required from each schedule that would be perfectly aligned with the cost study. Mr. Ehrbar uses the Relative Margin to Cost at Present Rates, on line 27, as a guide to spread the proposed increase by service schedule.

Q. Where did the revenue requirement components come from?

A. Exhibit No. 802 shows how the pro forma results of operations, including the requested revenue increase from Company witness Ms. Smith's Exhibit No. 501, have been assigned to the functional component classifications used in the cost of service.

Q. What are the results of the Company's LRIC study?

A. Table No. 1 below shows the relative margin-to-cost ratio at present rates for each rate schedule.

Table No. 1: Long Run Incremental Cost Study

Customer Class	LRIC Summary Component Allocation Relative Margin-to-Cost Present Rates
Residential Service Schedule 410	0.98
General Service Schedule 420	0.92
Large General Service Schedule 424	1.78
Interruptible Sales Service Schedule 440	1.47
Seasonal Sales Service 444	1.77
Transportation Service Schedule 456	1.66
Total Oregon Gas	1.00

The present relative margin-to-cost ratios indicate that general service (primarily commercial) customers on Schedule 420 are paying less than their relative cost of service, while large general (Schedule 424), interruptible (Schedule 440), seasonal (Schedule 444), and transportation (Schedule 456) service customers are paying more than their relative cost of service. Residential service customers on Schedule 410 are slightly below parity (1.00) on a relative margin-to-cost basis. The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. Please summarize your testimony regarding the LRIC study.

A. I have provided a long-run incremental cost study by service schedule for the Company's Oregon jurisdiction. The study incorporates the essential elements of providing service to customers over the long term. As a guideline for the proposed rate spread, the study indicates that it would be reasonable for residential customers on Schedule 410 and small general service customers on Schedule 420 to receive a larger percentage margin increase than other customer groups, and large general service, interruptible, seasonal, and transportation customers on Schedules 424, 440, 444 and 456 to receive either a rate decrease, or no rate change at all. This is reflected in Mr. Ehrbar's proposed rate spread.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

JOSEPH D. MILLER
Exhibit No. 801

Long-Run Incremental Cost of Service Study

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

RESULT SUMMARY *(Component Allocation)*

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS								
1	2016 ANNUAL THERM DELIVERIES	131,581,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
2	2016 CUSTOMERS	98,647	87,065	11,416	83	35	9	3	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4	Gas Commodity Costs	$ -	-	-	-	-	-	-	-
5	Gas Supply Department (Scheduling) 1.03189	$ 56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)	$ 142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading	$ 116,123	102,489	13,439	98	41	11	4	42
8	Billing	$ 2,437,937	2,151,696	282,139	2,051	865	222	74	890
	Customer Installation Investment Cost								
9	Meters	$ 4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
10	Services	$ 41,791,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	260,891
11	Main Extensions	$ 107,857,825	63,792,293	42,572,013	331,741	229,674	35,972	18,573	877,559
12	Total Customer Installation Investment Cost	$ 154,509,966	103,163,613	49,134,017	530,280	385,846	58,309	47,507	1,190,394
	System Core Main Cost								
13	Capacity	$ 12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14	Commodity	$ 12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost	$ 24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost	$ 1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost	$ 183,135,015	116,711,603	55,237,265	1,249,150	1,018,121	84,421	981,338	7,853,118
18	**Distribution Margin Revenue at Present Rates**	**$ 53,224,000**	**34,864,000**	**13,605,000**	**687,000**	**463,000**	**44,000**	**231,000**	**3,330,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
19	Cost of Gas Commodity	$ -	-	-	-	-	-	-	-
20	Gas Supply Department Costs	$ 568,000	303,900	165,043	28,446	24,644	1,603	6,899	37,466
21	Meter Reading, Billing, Etc. Costs	$ 3,686,000	3,253,222	426,575	3,101	1,308	336	112	1,345
22	Meters & Services Costs	$ 18,599,000	15,696,325	2,616,101	79,152	62,262	8,905	11,535	124,719
23	System Core Main Costs	$ 37,367,000	20,945,150	13,517,845	282,414	231,271	17,072	265,373	2,107,874
24	Underground Storage Costs	$ 1,561,000	906,149	480,161	53,680	46,934	1,002	11,364	61,709
25	**LRIC Based Target Margin**	**$ 61,781,000**	**41,104,746**	**17,205,725**	**446,794**	**366,419**	**28,919**	**295,284**	**2,333,113**
26	Current Distribution Margin Revenue to Proposed Cost	**0.86**	**0.85**	**0.79**	**1.54**	**1.26**	**1.52**	**0.78**	**1.43**
27	**Relative Margin to Cost at Present Rates**	**1.00**	**0.98**	**0.92**	**1.78**	**1.47**	**1.77**	**0.91**	**1.66**
28	Component LRIC Target Increase by Schedule	$ 8,557,000	$ 6,240,746	$ 3,600,725	$ (240,206)	$ (96,581)	$ (15,081)	$ 64,284	$ (996,887)
29	Target Increase as a Percent of Present Distribution Margin Revenue	16.08%	17.90%	26.47%	-34.96%	-20.86%	-34.28%	27.83%	-29.94%
30	Avg Cost Per Month for Meter Reading, Billing, Meters & Services		$ 18.14	$ 22.21	$ 82.58				$ 291.82

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

INCREMENTAL INVESTMENT COSTS

Line No.			Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	SERVICE INSTALLATIONS	48 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	3/4"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	3/4" - 2"	1/2" - 2"
2	AVERAGE SERVICE COST		$ 2,342.11	$ 2,633.95	$ 10,227.33	$ 19,629.92	$ 10,227.33	$ 29,981.42	$ 41,129.20
3	LEVELIZED PLANT COST FACTOR		0.1762	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
4	ANNUAL REVENUE REQUIREMENT		$ 412.68	$ 464.10	$ 1,802.06	$ 3,458.79	$ 1,802.06	$ 5,282.73	$ 7,246.97
	METERS & REGULATORS	36 yr life							
5	METERS & REGULATORS		$ 216.00	$ 604.88	$ 3,223.91	$ 5,482.40	$ 3,714.67	$ 23,836.64	$ 7,884.75
6	LEVELIZED PLANT COST FACTOR		0.1830	0.1830	0.1830	0.1830	0.1830	0.1830	0.1830
7	ANNUAL REVENUE REQUIREMENT		$ 39.53	$ 110.69	$ 589.98	$ 1,003.28	$ 679.78	$ 4,362.11	$ 1,442.91
	MAIN INVESTMENT	58 yr life							
8	AVERAGE MAIN EXTENSION PER CUSTOMER		112	568	382	498	382	792	1,165
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	sample	dedicated plt	same as 424	dedicated plt	dedicated plt
10	AVERAGE COST PER FOOT		$ 37.23	37.23	59.3	$ 74.81	59.3	$ 44.36	$ 118.66
11	MAIN EXTENSION INVESTMENT		$ 4,155.98	$ 21,151.85	$ 22,670.93	$ 37,221.25	$ 22,670.93	$ 35,115.41	$ 138,267.92
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	22.35%	24.81%	52.95%	50.42%	0.00%	87.79%	38.13%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.152883	$ 0.684040	$ 0.616215	$ 0.288731	$ 0.303219	$ -	$ 0.174146	$ 0.400952
14	2016 AVERAGE THERMS PER CUSTOMER	.	563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
15	CAPACITY MAIN INVESTMENT		$ 385.11	$ 1,437.01	$ 15,961.04	$ 34,437.18	$ -	$ 425,351.54	$ 443,180.27
16	INCR COMMODITY MAIN INVESTMENT PER THERM		0.540957	$ 0.540957	$ 0.540957	$ 0.540957	$ 0.540957	$ 0.540957	$ 0.540957
17	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
18	COMMODITY MAIN INVESTMENT		$ 304.56	$ 1,261.51	$ 29,904.11	$ 61,437.58	$ 15,537.37	$ 1,321,285.66	$ 597,930.75
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 4,845.66	$ 23,850.38	$ 68,536.08	$ 133,096.02	$ 38,208.30	$ 1,781,752.61	$1,179,378.94
20	LEVELIZED PLANT COST FACTOR	58 yr life	0.1763	0.1763	0.1763	0.1763	0.1763	0.1763	0.1763
21	ANNUAL REVENUE REQUIREMENT		$ 854.29	$ 4,204.82	$ 12,082.91	$ 23,464.83	$ 6,736.12	$ 314,122.98	$ 207,924.51
	UNDERGROUND STORAGE INVESTMENT								
22	BALANCING INVESTMENT PER TOTAL THROUGHPUT THERM		$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839
23	STORAGE INVESTMENT PER JANUARY SALES THERM		$ 0.381926	$ 0.381926	$ 0.381926	$ 0.381926	$ 0.381926		
24	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
25	2016 AVERAGE JANUARY SALES THERMS PER CUSTOMER		94	379	5,531	11,484	659		
26	UNDERGROUND STORAGE INVESTMENT		$ 39.19	$ 158.37	$ 2,435.23	$ 5,049.22	$ 419.41	$ 14,262.51	$ 6,454.32
27	LEVELIZED PLANT COST FACTOR	48 yr life	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
28	ANNUAL REVENUE REQUIREMENT		$ 6.91	$ 27.90	$ 429.09	$ 889.67	$ 73.90	$ 2,513.05	$ 1,137.25
29	**TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER**		**$ 1,313.40**	**$ 4,807.52**	**$ 14,904.03**	**$ 28,816.57**	**$ 9,291.86**	**$ 326,280.87**	**$ 217,751.63**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

INCREMENTAL OPERATING AND MAINTENANCE COSTS

Line No.		Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	GAS SUPPLY DEPARTMENT (SCHEDULING)							
1	ANNUAL HOURS (PER THERM)	0.0000131	0.0000131	0.0000131	0.0000131	0.0000131	0.0000065	0.0000065
2	AVERAGE RATE PER HOUR	$ 38.70	$ 38.70	$ 38.70	$ 38.70	$ 38.70	$ 38.70	$ 38.70
3	LABOR COST PER THERM	$ 0.00051	$ 0.00051	$ 0.00051	$ 0.00051	$ 0.00051	$ 0.00025	$ 0.00025
	GAS SUPPLY DEPARTMENT (NON-SCHEDULING)							
4	ANNUAL HOURS (PER THERM)	0.0000258	0.0000258	0.0000258	0.0000258	0.0000258	0.0000011	0.0000011
5	AVERAGE RATE PER HOUR	$ 62.07	$ 62.07	$ 62.07	$ 62.07	$ 62.07	$ 62.07	$ 62.07
6	LABOR COST PER THERM	$ 0.00160	$ 0.00160	$ 0.00160	$ 0.00160	$ 0.00160	$ 0.00007	$ 0.00007
7	**TOTAL GAS SUPPLY DEPARTMENT O&M PER CUSTOMER**	**$ 1.19**	**$ 4.91**	**$ 116.37**	**$ 239.07**	**$ 60.46**	**$ 780.85**	**$ 353.36**
	METER READING							
8	ANNUAL HOURS	0.04348	0.04348	0.04348	0.04348	0.04348	0.04348	0.04348
9	AVERAGE RATE PER HOUR	$ 26.24	$ 26.24	$ 26.24	$ 26.24	$ 26.24	$ 26.24	$ 26.24
10	LABOR COST PER CUSTOMER	$ 1.14078	$ 1.14078	$ 1.14078	$ 1.14078	$ 1.14078	$ 1.14078	$ 1.14078
	BILLING							
11	ANNUAL POSTAGE PER CUST	$ 2.96	$ 2.96	$ 2.96	$ 2.96	$ 2.96	$ 2.96	$ 2.96
12	5 YR AVERAGE PER CUST	$ 20.99	$ 20.99	$ 20.99	$ 20.99	$ 20.99	$ 20.99	$ 20.99
13	BILLING COST PER CUSTOMER	$ 23.95	$ 23.95	$ 23.95	$ 23.95	$ 23.95	$ 23.95	$ 23.95
14	**TOTAL CUSTOMER O&M**	**$ 25.09**	**$ 25.09**	**$ 25.09**	**$ 25.09**	**$ 25.09**	**$ 25.09**	**$ 25.09**

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

JOSEPH D. MILLER
Exhibit No. 802

Long-Run Incremental Cost of Service Study

Compute Functional Revenue Requirement

FUNCTIONAL CLASSIFICATION

Line No.	DESCRIPTION		Forecasted Total	Cost of Gas Commodity & Amortizations	Scheduling and Planning Costs	Meter Reading Billing, Etc Costs	Meters & Services Costs	System Core Main Costs	Underground Storage Costs
	a		-						
	REVENUES								
1	Revenue From Rates		$53,224	0	568	3,686	18,599	37,367	1,561
2	Proposed Increase		8,557						
3	Other Revenues		167				167		
4	Total Gas Revenues		61,948	0	568	3,686	18,766	37,367	1,561
	EXPENSES								
5	Exploration and Development		0						
	Production								
6	City Gate Purchases		0	0					
7	Purchased Gas Expense		0						
8	Other Gas Expenses		550		550				
9	Depreciation		0						0
10	Taxes		0						0
11	Total Production		550	0	550	0	0	0	0
	Underground Storage								
12	Operating Expenses		136						136
13	Depreciation		115						115
14	Taxes		64						64
15	Total Underground Storage		315	0	0	0	0	0	315
	Distribution								
16	Operating Expenses		8,303				2,776	5,527	
17	Depreciation		6,585				2,202	4,383	
18	Taxes		2,480				829	1,651	
19	Total Distribution		17,368	0	0	0	5,807	11,561	0
20	Customer Accounting		2,987			2,987			
21	Customer Service & Information		585			585			
22	Sales Expenses		0			0			
	Administrative & General								
23	Operating Expenses		8,625				2,830	5,634	162
24	Depreciation & Amortization		1,880				617	1,228	35
25	Taxes		2,440				801	1,594	46
26	Total Admin. & General		12,945	0	0	0	4,248	8,456	243
	Revenue Related Expenses								
27	Uncollectibles	0.005496	340	-	3	20	102	205	8
28	Commission Fees	0.002500	154	-	1	9	46	93	4
29	ERSA	0.000923	57	-	1	3	17	34	1
30	Franchise Fees	0.021987	1,359	-	12	81	409	822	34
31	Total Gas Expense	0.030906	36,661	0	568	3,686	10,630	21,171	605
32	OPERATING INCOME BEFORE FIT		25,287	0	0	0	8,136	16,195	956
	FEDERAL INCOME TAX								
33	Current and Deferred FIT		4,402	-	-	-	1,416	2,820	166
34	Debt Interest		(478)				(154)	(306)	(18)
35	FIT on Revenue Increase	0.312046	2,670	-	-	-	859	1,710	101
36	State Income Tax		1,213	-	-	-	390	777	46
37	SIT on Revenue Increase	0.077535	663	-	-	-	213	425	25
38	NET OPERATING INCOME		$16,816	$0	$0	$0	$5,410	$10,770	$636
39	Interest Expense	2.77%	6,034	0	0	0	1,941	3,865	228
	RATE BASE: PLANT IN SERVICE								
40	Production Plant		8						8
41	Underground Storage Plant		6,040						6,040
42	Transmission Plant		0						
43	Distribution Plant		315,538				105,505	210,033	
44	General Plant		46,829				15,364	30,584	881
45	Total Plant in Service		368,415	0	0	0	120,869	240,617	6,929
	ACCUMULATED DEPRECIATION								
46	Production Plant		0						0
47	Underground Storage Plant		(742)						(742)
48	Transmission Plant		0						
49	Distribution Plant		(97,505)				(32,602)	(64,903)	
50	General Plant		(12,090)				(3,966)	(7,896)	(227)
51	Total Accum. Depreciation		(110,337)	0	0	0	(36,568)	(72,799)	(969)
52	DEFERRED FIT		(52,228)				(17,135)	(34,111)	(982)
53	GAS INVENTORY		3,078						3,078
54	PREPAID PENSION		5,655				1,855	3,693	106
55	WORKING CAPITAL		3,241				1,063	2,117	61
56	TOTAL RATE BASE		$217,824	$0	$0	$0	$70,084	$139,517	$8,223
57	RATE OF RETURN		7.72%	#DIV/0!	#DIV/0!	#DIV/0!	7.72%	7.72%	7.72%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF PATRICK D. EHRBAR
REPRESENTING AVISTA CORPORATION

2016 Test Year Revenue Load Adjustment, Rate Spread, Rate Design, and Decoupling

I. INTRODUCTION

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

A. My name is Patrick D. Ehrbar and my business address is 1411 East Mission Avenue, Spokane, Washington. My present position is Manager of Rates and Tariffs.

Q. Would you briefly describe your duties?

A. Yes. My primary areas of responsibility include electric and natural gas rate design, customer usage and revenue analysis, and tariff administration.

Q. Please briefly describe your educational background and professional experiences.

A. I am a 1995 graduate of Gonzaga University with a Bachelors degree in Business Administration. In 1997 I graduated from Gonzaga University with a Masters degree in Business Administration. I started with Avista in April 1997 as a Resource Management Analyst in the Company's DSM department. Later, I became a Program Manager, responsible for energy efficiency program offerings for the Company's educational and governmental customers. In 2000, I was selected to be one of the Company's key Account Executives. In this role I was responsible for, among other things, being the primary point of contact for numerous commercial and industrial customers, including delivery of the Company's site-specific energy efficiency programs.

I joined the State and Federal Regulation Department as a Senior Regulatory Analyst in 2007. Responsibilities in this role included being the discovery coordinator for the Company's rate cases, line extension policy tariffs, as well as miscellaneous regulatory issues. In November 2009, I was promoted to my current role.

Q. What is the scope of your testimony in this proceeding?

A. In addition to discussing the Company's 2016 Test Year Revenue Load Adjustment, my testimony in this proceeding will cover the spread of the proposed annual margin/revenue increase among the Company's natural gas service schedules as well as the application of the increase to the rates within each of the schedules. The results of the Long-run Incremental Cost study ("LRIC") sponsored by Company witness Mr. Miller were used as a guide to spread the proposed margin/revenue increase by service schedule. Finally I will provide the details of the Company's proposed Natural Gas Decoupling Mechanism.

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

A. Yes. I am sponsoring Exhibit Nos. 901, 902, 903, and 904 which were prepared under my direction.

Q. Would you please explain what is contained in Exhibit No. 901 and 902?

A. Yes. Exhibit No. 901 contains the present natural gas rates and schedules which are on file with the Commission as a part of our present tariff, PUC OR. No. 5. Exhibit No. 902 contains the proposed natural gas rates and schedules which reflect the proposed annual revenue increase of $8,557,000.

Q. What is contained in Exhibit No. 903?

A. Exhibit No. 903 contains information regarding the proposed rate spread and rate design of the proposed annual revenue increase of $8,557,000. Page 1 shows customer usage information by service schedule for 2013, 2014, and forecasted for 2015 and 2016. Page 2 shows the application of the overall margin/revenue increase by service schedule and the LRIC results before and after application of the proposed increase. Page 3 shows the proposed revenue and percentage increase by service schedule. Page 4 shows the present base rates under each of the schedules, the proposed changes to those rates, and the rates after application of the proposed changes. The information contained in these pages will be referred to and discussed later in my testimony.

Q. What is contained in Exhibit No. 904?

A. Exhibit No. 904 contains the information related to the Company's Natural Gas Decoupling Mechanism, the components of which are described later in my testimony.

II. REVENUE ADJUSTMENT AND CUSTOMER USAGE

Q. Would you please describe the 2016 Test Year Revenue Load Adjustment?

A. Yes. The 2016 Test Year Revenue Load Adjustment, included in this filing as Adjustment 2.01 in Company witness Ms. Smith's Exhibit No. 501, represents the difference between the Company's restated historical test year revenue during 2014 and forecasted revenue for 2016. Actual revenue for 2014 was restated for adjustments 1.01 through 1.06 as discussed by Ms. Smith. These adjustments include test year weather normalization and the elimination of adder schedules. Revenue for 2016 is based on customer usage and number of customers from the Company's most recent load forecast applied to the present natural gas rates in effect as of April 16, 2015.[1]

Q. You mentioned that customer usage for 2016 was taken from the Company's most recent load forecast. Could you please explain?

A. Yes. The most recent natural gas load forecast of the number of customers and

[1] Effective April 16, 2015, the Commission approved a base rate increase of $5.0 million in Docket UG-284, the Company's last general rate case.

total therm usage for future periods was completed in July 2014. The information from that load forecast was used in the 2016 Test Year Revenue Load Adjustment. Company witness Dr. Forsyth provides further details in his testimony related to the customer and load forecast used in this case.

Q. In Docket No. UG-246, what was agreed to as it relates to the forecast used for the ratemaking purposes?

A. The Company agreed that it would use the most recent forecast of customer counts and natural gas usage that is used for financial reporting purposes in its future general rate cases, Integrated Resource Plans, and PGA proceedings. The Company used in this case the most recent forecast of customer counts and natural gas usage that is used for financial reporting, for all customer classes/schedules.

Q. How does 2016 customer usage compare to weather-normalized usage for prior periods?

A. Page 1 of Exhibit No. 903 shows actual and weather-normalized usage by rate schedule for 2013 and 2014, the forecasted usage for 2015, and the test year usage for 2016 used in this filing. As shown on lines 36 and 38, total throughput (sales and transportation volumes) is projected to increase by approximately 5.4% over the two-year period. However, only approximately 33% of the projected load increase is from higher margin sales customers, with the other 67% coming from lower margin transportation customers.

Q. How does the 2016 usage for residential customers compare to 2014?

A. As shown in Exhibit No. 903, page 1 lines 2 and 4, total 2016 usage for residential customers is 2.7% higher than total weather-normalized residential usage in 2014. In evaluating residential monthly use-per-customer, 2016 use-per-customer is 1.3% higher than monthly use-per-customer (weather-normalized) in 2014.

Q. How does 2016 usage for commercial customers compare to 2014 usage for that customer classes?

A. As shown in Exhibit No. 903, page 1 lines 8 and 10, total 2016 usage for commercial customers is 1.1% higher than weather-normalized commercial usage in 2014.

Q. What is the impact on the Company's net operating income and revenue requirement resulting from the 2016 increase in natural gas loads?

A. As Ms. Smith describes in her direct testimony (Exhibit No. 500), the effect of the April 2015 general rate increase of $5 million, and the increase in loads in 2016 as compared to 2014, results in an increase to net operating income of approximately $4.1 million and a reduction to revenue requirement of approximately $7.1 million. The 2016 Test Year Revenue Load Adjustment is Adjustment 2.01 in Exhibit No. 501.

Q. Is the Company proposing any changes to the present allocation of natural gas costs by rate schedule used in its PGA filings?

A. No, it is not.

III. PROPOSED RATE DESIGN AND RATE SPREAD

Q. Would you please provide an explanation of margin revenue and total revenue that you will discuss in your testimony?

A. Yes. Throughout my testimony I will refer to "margin revenue" and "total revenue". Margin revenue refers to the base revenue associated with the Company's ownership and operation of its natural gas distribution operations. It is the revenue related to delivering natural gas to customers, and does not include the cost of natural gas, upstream third-party owned transportation, or the effect of other tariffs.

Total revenue, on the other hand, consists of margin revenue as well as the cost of natural gas, transportation, demand side management, low income rate assistance, intervenor funding, and other items. Total revenue, and the percentage increase for the schedules, is the metric that reflects the proposed bill increase for customers on all service schedules.

Q. Would you please describe the Company's present rate schedules and the types of natural gas service offered under each?

A. Yes. Table No. 1 below shows the type of customer and the number of customers served as of December 31, 2014, under each of the Company's Oregon natural gas schedules:

Table No. 1:

Natural Gas Customers by Schedule

Rate Schedule	No. of Customers
Residential Schedule 410	86,711
General Service Schedule 420	11,327
Large General Service Schedule 424	81
Interruptible Service Schedule 440	33
Seasonal Service Schedule 444	2
Special Contract Schedule 447	4
Transportation Service Schedule 456	36

Q. How does the Company propose to spread the proposed base margin revenue increase of $8,557,000 among its various service schedules?

A. The Company utilized the results of the LRIC sponsored by Company witness Mr. Miller as a guide to spread the proposed margin/revenue increase by service schedule. The Company spread the proposed increase for all schedules in a manner that results in the margin-to-cost ratios for the various service schedules moving approximately 50% closer to 1.00 (unity). Table No. 2 below shows the margin-to-cost ratio under present revenues.

Table No. 2: Present Margin to Cost

	Margin to Cost at Present Rates
Residential Schedule 410	0.98
General Service Schedule 420	0.92
Large General Service Schedule 424	1.78
Interruptible Service Schedule 440	1.47
Seasonal Service Schedule 444	1.77
Transportation Service Schedule 456	1.66
Overall	**1.00**

The current margin-to-cost ratio for Schedules 410 and 420 are below unity. This means the margin revenues provided by customers served under these schedules are below the full cost of serving these customers. They are, in essence, being subsidized by the other non-residential customer schedules. In contrast, the margin revenues for Schedules 424, 440, 444 and 456 are above the cost of service.

Q. Using the Company's proposed rate spread, what is the proposed percentage increase in margin revenue and total revenue for each schedule, and what is the effect on the margin-to-cost ratios?

A. Table No. 3 below shows the proposed percentage increase in margin and total revenue (including natural gas and other costs) for each service schedule:

Table No. 3:

Proposed % Natural Gas Increase by Schedule

Rate Schedule	Increase in Margin Revenue	Increase in Total Revenue
Residential Schedule 410	17.0%	8.9%
General Service Schedule 420	21.4%	9.5%
Large General Service Schedule 424	-7.0%	-1.3%
Interruptible Service Schedule 440	0.0%	0.0%
Seasonal Service Schedule 444	-7.0%	-1.5%
Transportation Service Schedule 456	-7.0%	-6.9%
Overall	**16.1%**	**8.0%**

Table No. 4 below shows the effect on the margin-to-cost ratios from the proposed rate spread. Requesting no rate change for Schedule 440 provides meaningful movement (approximately 50%) towards unity for this schedule. For Schedules 424, 444 and 456, an approximate 50% movement towards unity provides for a margin rate reduction which the Company believes is reasonable given the results of the LRIC. If approved as filed, these schedules would still have a margin-to-cost ratio in excess of 1.0, and therefore, in the Company's view, the proposed rate spread is not only reasonable, but needed. This information is also shown in more detail on page 2 of Exhibit No. 903.

Table No. 4:

Present and Proposed Margin to Cost

	Margin to Cost at Present Rates	Margin to Cost at Proposed Rates
Residential Schedule 410	0.98	0.99
General Service Schedule 420	0.92	0.96
Large General Service Schedule 424	1.78	1.43
Interruptible Service Schedule 440	1.47	1.26
Seasonal Service Schedule 444	1.77	1.41
Transportation Service Schedule 456	1.66	1.33
Overall	**1.00**	**1.00**

More detailed information related to the revenue increase by schedule is shown on Page 3 of Exhibit No. 903.

Q. Turning now to the proposed changes to the rates within the various service schedules, could you please describe what is shown on Page 4 of Exhibit No. 903?

A. Yes. Page 4 of Exhibit No. 903 shows the present rates for each of the various schedules, the proposed changes to those rates, and the resulting proposed rates.

Q. Please describe the proposed changes in the rates for Residential Schedule 410 that result in the overall margin revenue increase of 17.0% for that Schedule.

A. As shown on Page 4 of Exhibit No. 903, the Company is proposing an increase in the present monthly customer charge of $2.00 per month, from $8.00 to $10.00. The present charge per therm would be increased by $0.07824 per therm, from $0.54073 to $0.61897 per therm. These changes result in an overall proposed increase of 17.0% in margin revenue for the Schedule (8.9% on a total revenue basis).

Q. Why is the Company proposing to increase the basic charge for Schedule 410?

A. A significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. As shown in Company witness Mr. Miller's Exhibit No. 801, the costs associated with billing, meter reading, meters and services are $18.14 per month for Schedule 410.[2] The Company believes that it is appropriate to recover a more reasonable level of these fixed customer costs through the basic charge.

[2] See Exhibit 801, Page 1 line 30.

Q. Does a decoupling mechanism remove the need for a meaningful increase in the monthly basic charge?

A. No, it does not. While a decoupling mechanism would provide Avista with the opportunity to recover its fixed costs, the fact is that those costs are still being paid on a volumetric basis. Therefore, higher use customers pay more fixed costs and subsidized lower use customers pay less. Increasing the basic charge will reduce this intra-schedule cross subsidization.

Q. What is the change in the average bill for a residential customer as a result of these proposed changes?

A. Based on an average usage level of 47 therms per month, the average bill for a residential customer, which includes both base and adder schedules, would increase $5.68 per month, or 8.9%, from $63.65 to $69.33.

Q. Could you please describe the changes you propose to the rates of General Service Schedule 420?

A. Yes. As shown on Page 4 of Exhibit No. 903, the present rates for service under Schedule 420 consist of a $14.00 per month customer charge and a base volumetric rate of $0.43901 per therm. The Company is proposing an increase in the customer charge of $6.00 per month, from $14.00 to $20.00, and an increase of $0.07869 per therm in the usage charge. These changes result in an overall proposed increase of 21.4% in margin revenue for the Schedule (9.5% on a total revenue basis).

Q. Please describe the service provided and the proposed rate changes under Large General Service Schedule 424 and Seasonal Service 444?

A. Yes. Large General Service Schedule 424 provides service to customers whose usage is at least 75% for uses other than space-heating and who have a relatively high load-factor compared to other firm service customers. The Company is proposing a decrease of $0.01045 per therm to the present volumetric rate under the Schedule and no change in the present monthly customer charge of $50.00 per month. The resulting decrease in margin revenue is 7.0%, or 1.3% on a total revenue basis.

Seasonal Service Schedule 444 is for customers who use no natural gas during December, January and February. Depending on the season, as many as nine customers are served under the Schedule, most of whom are mint farmers. Customers served under this Schedule are not assessed a monthly customer charge. The Company is proposing a decrease in the per therm charge under the Schedule of $0.01201 per therm, resulting in an overall decrease of 7.0% in margin revenue under the Schedule, or 1.5% on a total revenue basis.

Q. Please describe the service provided and the proposed rate changes under Interruptible Schedule 440.

A. Interruptible Service Schedule 440 serves customers that are able to curtail their natural gas usage or switch to an alternate fuel upon relatively short notice by the Company. These customers are not assigned firm pipeline transportation costs through their rates, as they do not create peak service requirements. The Company is proposing that, in order to achieve an approximately 50% movement towards unity, the schedule should not have a rate adjustment.

Q. Please describe the proposed changes to the present rates for Transportation Service Schedule 456.

A. Transportation Schedule 456 provides Company distribution service for large customers who use over 225,000 therms per year. These customers purchase natural gas and pipeline transportation from a third party. As shown on Page 4 of Exhibit No. 903, the present rates under the Schedule consist of a monthly customer charge of $275.00 and a five-block rate structure with declining rates for higher usage. Given the proposed 7.0% margin revenue decrease for the schedule, the Company is proposing to leave the monthly customer charge unchanged, and that the decrease be applied on a uniform percentage basis of 7.3% to all rate blocks under the Schedule.[3]

IV. NATURAL GAS DECOUPLING MECHANISM

Q. Is the Company requesting a natural gas decoupling mechanism in this general rate case?

A. Yes, the Company is requesting a Natural Gas Decoupling Mechanism ("Decoupling Mechanism"). The Company believes, for reasons stated below, that the mechanism would provide benefits to both customers and the Company, and therefore is in the public interest and should be approved.[4]

Q. Do you believe that the Decoupling Mechanism proposed by the Company is in line with principles the Commission has stated in the past?

[3] For Schedule 456, including an estimate of 45.0 cents per therm for the cost of natural gas and pipeline transportation, the proposed decrease to Schedule 456 rates represents an average decrease of 1.1% in those customers' total natural gas bill.

[4] The Company is proposing that the Decoupling Mechanism go into effect on the first day of the calendar month that is equal to, or subsequent to, the effective date of new retail rates from this case.

A. Yes. The proposed mechanism is in keeping with the Commission's previously-stated views on decoupling. In Order 13-459 in Docket UE-262 (Portland General Electric), at p. 11, the Commission stated:

> "Commission Resolution. The stipulation relating to the decoupling mechanism is adopted. In Order No. 09-020, docket UE 197, the Commission approved a decoupling mechanism designed to achieve a number of goals, including, among others, removing the relationship between sales and profits, mitigating PGE's disincentives to promote energy efficiency, and improving PGE's ability to recover its fixed costs."

The mechanism requested in this case removes the relationship between sales and profits, mitigates the disincentive to promote energy efficiency, and improves fixed cost recovery.

Q. Before describing the mechanism, would you please provide further details on how the mechanism benefits the Company and its customers?

A. Yes. To the extent use-per-customer declines between general rate cases, the decoupling mechanism would provide recovery of the fixed costs of providing service to its customers. These are the same fixed costs, on a revenue-per-customer basis, that the Commission approves for recovery in a general rate case. The mechanism would also ensure that, to the extent there is customer growth in the rate year and beyond, the revenues from those new customers would be available to offset the growth in utility costs following the test year.

Customers benefit from the proposed mechanism. By decoupling sales from revenue, the disincentive to promote conservation would be removed, as would any incentive for the utility to increase throughput. Customers benefit if the overall actual sales revenue collected by the Company on a per-customer basis is greater than that approved by the Commission. For example, if a winter is colder than normal, leading to loads that are higher than normal, the Company would rebate to customers all of the revenue collected above the allowed level. And on the other hand, should sales be lower due to warmer than normal winter weather, those lost revenues would be deferred for later surcharge to customers. With approval of the Decoupling Mechanism by the Commission, the tracking of lost margin through Schedule 478, DSM Cost Recovery, that results from the Company's energy efficiency programs, would be eliminated.

In summary, the Company's proposed decoupling mechanism would ensure that it would be able to recover the fixed costs of providing service to customers, on a revenue-per-customer basis. In a colder than normal winter, if the Company collects revenues that are greater than the amount authorized, those revenues would be returned to customers.

Q. Is weather normalized as a part of the proposed mechanism?

A. No, the proposed decoupling mechanism does not have a weather normalization adjustment. The Company has a certain level of fixed costs that are recovered in its variable energy rates. If weather were to be normalized as part of the mechanism, the mechanism would not provide the same level of fixed cost recovery as determined in the last general rate case. With the Company's proposed mechanism, should sales be higher due to colder than normal winter weather, those additional revenues would be deferred and returned to customers. And on the other hand, should sales be lower due to warmer than normal winter weather, those lost revenues would be deferred for later surcharge to customers.

Q. What is the Company's view on proposals to reduce the allowed return on equity (ROE) in the event the Commission were to adopt decoupling?

A. The Company believes that an adjustment to the Company's cost of equity is not warranted. As stated by Company witness Mr. McKenzie:[5]

> Because the utilities in my proxy groups operate under a wide variety of regulatory mechanisms, including decoupling, the mitigation in risks associated with Avista's requested decoupling mechanism is already reflected in the results of my analyses, and no separate adjustment to the Company's ROE is necessary or warranted.

The Washington Utilities and Transportation Commission, in their approval of a similar mechanism for Puget Sound Energy, stated:[6]

> In terms of the arguments that implementing decoupling reduces the Company's cost of equity there again is no empirical evidence to show this is so. Indeed, the record does not even fully support the proposition that equity markets recognize and respond to the forms of risk reduction that accompany the implementation of decoupling mechanisms. While this cannot be said to disprove the theory that decoupling reduces risk and, therefore, cost of capital, the more important point from the Commission's perspective is that <u>absent evidence actually demonstrating the theory's effect in practice</u> on either the debt or equity markets <u>there is no evidentiary basis</u> upon which the Commission can order a reduction in the Company's cost of capital. (emphasis added)

The revenue provided to Avista through a decoupling mechanism would <u>not</u> represent additional revenue to the Company over and above what is needed to recover its costs; it represents <u>restoration</u> of revenues that the Commission has already determined should be provided to the utility from the last rate case. Furthermore, customers can expect to see rebates as well as surcharges over time with the decoupling mechanisms.

Q. Does the Company propose that the Decoupling Mechanism be subject to an earnings test?

A. No, it does not. Avista believes, consistent with Northwest Natural's decoupling mechanism, the proposed mechanism is an automatic adjustment clause under ORS 757.210, and therefore should not be subject to a separate earnings review.

[5] Exhibit No. 300, p. 7, ll. 10-14.
[6] Order No. 07, Puget Sound Energy, Dockets UE-121697 et. al., ¶ 104

ELEMENTS OF THE NATURAL GAS DECOUPLING MECHANISM

Q. Would you please provide a summary of how the proposed decoupling mechanism would function?

A. Yes. First, it is important to note that Avista generally is using the same methodology as its approved natural gas decoupling mechanism in Washington. As I will explain in more detail below, the Company is proposing a Revenue-Per-Customer decoupling mechanism for its Oregon natural gas operations. The proposed decoupling mechanism compares the actual, non-weather adjusted revenues to the allowed revenue determined on a per-customer basis, with any differences deferred for later rebate or surcharge. In addition, the Company is proposing to group customers into two Rate Groups – Residential and Non-Residential. More discussion on the two Rate Groups will follow later in my testimony.

Q. For the Decoupling Mechanism, would you please describe how the Decoupled Revenue is determined?

A. Yes. Provided on Page 1 of Exhibit No. 904 is information that calculates the Decoupled Revenue. This is the revenue associated with the delivery of natural gas that the Company collects in its variable energy rates to cover the fixed costs of providing service to customers. It excludes revenues associated with natural gas and other non-delivery related tariffs (Intervenor Funding, DSM, etc.), and excludes revenues that are collected in fixed basic charges. The steps to calculate Decoupled Revenue are explained below:

- Step 1 – Determine Total Delivery Revenue - Lines 1 through 3 on Page 1 of Exhibit No. 904 shows the Total Normalized 2016 Revenue from the test year ($53.0 million) and adds to that total the Proposed Revenue Increase ($8.6 million). The resulting calculation is the Proposed Total Revenue that the Company has requested in this case ($61.6 million).[7]

- Step 2 – <u>Remove Basic Charge Revenue</u> – Included in the Delivery Revenue on Line 3 are revenues that are recovered from customers in fixed monthly Basic Charges. Because the proposed decoupling mechanism only tracks revenue that varies with customer usage, the revenue from Basic Charges must be removed. Line 4 shows the number of Customer Bills in the test year, and Line 5 shows the Proposed Basic Charges in this case. Line 6 is the total Basic Charge Revenue which is calculated by taking the number of customer bills and multiplying those by the associated Fixed Charges, by rate schedule.
- Step 3 – <u>Determine Decoupled Revenue</u> – The final step to calculate the <u>allowed</u> Decoupled Revenue, as shown on Line 7, is to subtract the Basic Charge Revenue (Line 6) from the Delivery Revenue (Line 3).

Q. Would you please describe how the Allowed Decoupled Revenue <u>per Customer</u> is determined?

A. Yes. Provided on Page 2 of Exhibit No. 904 are the inputs and calculations to determine the Allowed Decoupled Revenue per Customer. Line 1 on Page 2 of Exhibit No. 904 shows the Decoupled Revenue, by Rate Group, that was calculated earlier. Note that the information on Page 2 now shows the revenues by Rate Group rather than by individual rate schedule. More discussion related to the Rate Groups will follow later in my testimony. Line 2 shows the 2016 Test Year Number of Customers, by Rate Group. Finally, Line 3 divides

[7] If the Commission approves basic charges that are different than what the Company proposed, the basic charges included in Exhibit 904, p. 1, ln. 5 would need to be updated.

the Decoupled Revenue by the Test Year Number of Customers to determine the annual Decoupled Revenue per Customer.

Page 3 of Exhibit No. 904 calculates the monthly Decoupled Revenue per Customer. To determine the monthly Decoupled Revenue per Customer, the annual Decoupled Revenue per Customer is shaped based on the monthly therm usage from the test year as shown on Page 3 of Exhibit No. 904. For example, the Residential Group is forecast to use 16.85% of its annual usage in January 2016 (8,259,327 therms / 49,018,942 annual therms). The Company used the resulting monthly percentage of usage by month and multiplied that value by the annual Allowed Decoupled Revenue per Customer to determine the 12 monthly values shown by Rate Group on lines 14 and 18. As described below, those monthly values will then be multiplied by the actual number of customers in the appropriate month to determine the allowed decoupled revenue.

Q. Please describe how deferrals for the Decoupling Mechanism would be calculated.

A. In the rate year, the Company would track the Actual Decoupled Revenue it receives and defer any difference between that amount and the Allowed Decoupled Revenue. Deferrals would be tracked separately for each Rate Group. A sample calculation, provided for illustrative purposes, is included on Page 4 of Exhibit No. 904. Detailed below are the steps outlined on Page 4 to calculate the deferral.

For purposes of describing the deferral calculation, I will only refer to the calculation of the deferral for the Residential Group; there is no difference in the calculations for the Non-Residential Group.

- Step 1 – Determine Allowed Decoupled Revenue – The first step is to pull from the Company's billing system the actual number of customers each month. Line 1 on Page 4 of Exhibit No. 904 shows, for illustrative purposes, the Residential Group actual level of customers for the Rate Year of 2016. Line 2 shows the Monthly Allowed Decoupled Revenue per Customer for that group. Multiplying those values together results in an Allowed Decoupled Revenue for each month, shown on Line 3. The calculated values on Line 3 show, by month, the total amount of revenue that the Company would be allowed.
- Step 2 – Determine Actual Decoupled Revenue – The next step is to pull from the Company's billing system the Actual Monthly Delivery Revenue excluding natural gas costs (Line 4 on Page 4 of Exhibit No. 904), and Actual Fixed Charge Revenue (Line 5). These "actuals" would not be weather normalized. Line 6 on Page 4 of Exhibit No. 904 shows the calculation of the Actual Decoupled Revenue. This calculation subtracts from Actual Monthly Delivery Revenue on Line 4 the Actual Fixed Charge Revenue (Line 5). The calculated values on Line 6 show, by month, the Actual Decoupled Revenue (e.g., the actual fixed costs recovered in volumetric rates).
- Step 3 – Deferral Calculation – In order to determine if the Company over- or under-recovered its fixed costs, Actual Decoupled Revenue (Line 6 on Page 4 of Exhibit No. 904) is subtracted from Allowed Decoupled Revenue (Line 3). Line 7 shows the calculation. If the number is positive (surcharge direction), then the Company under-recovered its allowed revenue. If the number is negative, then the Company over-recovered its allowed revenue. On line 8 the "Interest on Deferral" would accrue at

the Company's authorized rate of return, similar to other Company deferrals. Finally, Line 9 shows the Cumulative Deferral[8].

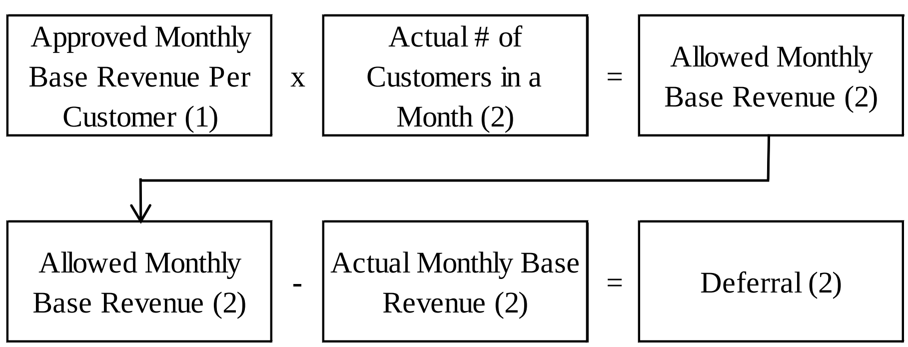
In summary, the calculations shown on Page 4 of Exhibit No. 904 provide an example of how the Natural Gas Decoupling Mechanism would work. It shows the use of the Monthly Allowed Decoupled Revenue per Customer and how that value is applied to the actual level of customers to determine the Allowed Decoupled Revenue opportunity. Further the example shows how actual revenue from Fixed Charges are removed from actual delivery revenue to determine the Actual Decoupled Revenue. Finally, the example shows the monthly and cumulative deferral calculations, including the effect of interest.

Q. Please provide a high-level summary of the mechanics of the Decoupling Mechanism deferral calculation.

A. Illustration No. 1 below provides a high-level overview of the deferral calculation mechanics:

<u>Illustration No. 1:</u>

<u>Overview of Natural Gas Decoupling Mechanism Mechanics</u>



(1) See Exhibit No. 904, p. 3 for the calcuation
(2) See Exhibit No. 904, p. 4 for an illustrative example

[8] Note that the deferral calculations would be completed at the revenue level. The actual deferral would have an additional calculation to remove revenue related expenses. The final deferred balance which the Company would file for later rebate or recovery from customers would then be grossed up for revenue related expenses.

Q. Earlier in your testimony you mentioned that customers will be combined into Rate Groups. Please explain.

A. Avista has combined customers into two Rate Groups:

1. Residential – Schedule 410
2. Commercial – Schedules 420, 424, 440, and 444

Schedules 447 (Special contracts) and 456 (Transportation Service) were not included in the design of the Natural Gas Decoupling Mechanism. Two of the items that ultimately impact the Company's fixed cost recovery relate to weather and participation in the Company's energy efficiency programs. Transportation customers served on Schedules 447 and 456 do not participate in the Company's energy efficiency programs, and their usage is not weather-dependent. As such, the Company believes that the fixed costs recovered in these customer's variable rates tend to be more stable, and therefore do not need to be included in the mechanism.

Q. Please provide information related to when the Company would file for a rate adjustment under the proposed Decoupling Mechanism.

A. On or before August 1, the Company would file a proposed rate adjustment (surcharge or rebate) based on the amount of deferred revenue recorded for the prior January through December time period. The rate adjustment would be calculated separately for each Rate Group. The results of the "3% Rate Increase Limitation" test, discussed later in my testimony, would also be included with the filing and used to determine the amount of the rate adjustment.

The proposed tariff included with that filing would include a rate adjustment that recovers/rebates the appropriate deferred revenue amount over a twelve-month period effective on November 1, coincident with the annual PGA rate adjustment. The deferred revenue approved for recovery or rebate would be transferred to a balancing account and the revenue surcharged or rebated during the period would reduce the deferred revenue in the balancing account. Any deferred revenue remaining in the balancing account would be added to the new revenue deferrals to determine the amount of the proposed surcharge/rebate for the following year.

After determining the amount of deferred revenue that can be recovered through a surcharge (or refunded through a rebate) by Rate Group, the proposed rates under the Schedule would be determined by dividing the deferred revenue to be recovered by Rate Group by the estimated therm sales for each Rate Group during the twelve-month recovery period. Interest would accrue on deferrals at the Company's authorized rate of return, similar to other Company deferrals. Once a deferral balance is approved for amortization, interest will accrue at the Modified Blended Treasury Rate, similar to other Company amortizations.

Q. Would you describe the accounting for the proposed Natural Gas Decoupling Mechanism?

A. Yes. The Company would record the deferral in Account 186 – Miscellaneous Deferred Debits. The amount approved for recovery or rebate would then be transferred into a Regulatory Asset or Regulatory Liability account for amortization. On the income statement, the Company would record both the deferred revenue and the amortization of the deferred revenue through Account 495 – Other Gas Revenues, in separate sub-accounts. The Company would file quarterly reports with the Commission showing pertinent information regarding the status of the current deferral. This report would include a spreadsheet showing the monthly revenue deferral calculation for each month of the deferral period (January - December), as well as the current and historical monthly balance in the deferral account.

Q. Should there be a limit on any decoupling-related annual rate increases?

A. Yes, Avista proposes that there would a 3% Rate Increase Limitation test related to decoupling, and that there would be no limit on any annual decoupling rate reductions.

Q. Please describe the 3% Rate Increase Limitation Test.

A. The amount of the rate increase resulting from the decoupling adjustment would be subject to an annual <u>incremental</u> limit of 3%, <u>i.e.</u>, the annual increase in the surcharge cannot exceed a 3% rate increase each year, with unrecovered balances carried forward to future years for recovery. The incremental surcharge (percentage) increase is determined by subtracting the annual revenue amount recovered by the <u>present</u> surcharge rate from deferred revenue to be recovered through the proposed surcharge rate, and dividing that net amount by the total "normalized" revenue by Rate Group for the most recent January through December period. The normalized revenue is determined by multiplying the weather-corrected usage for the period by the present billing rates in effect.[9] If the incremental surcharge exceeds a 3% rate increase, only a 3% increase is implemented and any additional deferred revenue would remain in the deferred revenue account, and could be recovered the following year, subject to the 3% limitation. Again, the 3% limitation is not applicable if the Company is in a rebate position.

Q. Has the Company prepared natural gas tariffs that would administer the decoupling mechanism?

A. Yes, included in Exhibit No. 902 is a new tariff Schedule 475. This tariff outlines the mechanics of the decoupling mechanism and will serve as the rate adjustment

[9] Inclusive of booked billed revenue, booked unbilled revenue and the weather adjustment.

tariff.

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

A. Yes it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

PATRICK D. EHRBAR
Exhibit No. 901

Present Natural Gas Service Tariffs

SCHEDULE 410

GENERAL RESIDENTIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:
Applicable to residential natural gas service for all purposes.

TERRITORY:
This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:
The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	**$8.00**
Commodity Charge Per Therm:	
Base Rate	$0.54073
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)
Schedule 476 – Intervenor Funding	$0.00150
Schedule 478 – DSM Cost Recovery	$0.01789
Schedule 493 – Low Income Rate Assistance Program	$0.00451
Schedule 497 – Capital Cost Reovery	$0.00000
Total Billing Rate *	**$1.18405**

Minimum Charge:
The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	**$14.00**
Commodity Charge Per Therm:	
Base Rate	$0.43901
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)
Schedule 478 – DSM Cost Recovery	$0.01789
Schedule 497 – Capital Cost Recovery	$0.00000
Total Billing Rate *	**$1.07632**

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month
Customer Charge:	**$50.00**
Commodity Charge Per Therm:	
Base Rate	$0.13887
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)
Schedule 478 – DSM Cost Recovery	$0.01789
Schedule 497 – Capital Cost Recovery	$0.00000
Total Billing Rate *	**$0.77618**

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Commodity Charge Per Therm:	
Base Rate	$0.11652
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.41155
Schedule 462 – Gas Cost Rate Adjustment	$0.05099
Schedule 476 – Intervenor Funding	$0.00135
Schedule 497 – Capital Cost Recovery	$0.00000
Total Billing Rate *	**$0.58041**

Annual Minimum Charge:

Each Customer shall be subject to an Annual Minimum Charge if their gas usage during the prior year does not equal or exceed 50,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 11.652 cents per therm.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Commodity Charge Per Therm:	
Base Rate	$0.17155
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)
Schedule 478 – DSM Cost Recovery	$0.01789
Schedule 497 – Capital Cost Recovery	$0.00000
Total Billing Rate *	**$0.80886**

Minimum Charge:
$5,810.92 per season.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	**$275.00**

Volumetric Charge Per Therm:

	Base Rate	Schedule 476	Schedule 497	Billing Rate*
First 10,000	$0.14978	$0.00135	$0.00000	**$0.15113**
Next 20,000	$0.09014	$0.00135	$0.00000	**$0.09149**
Next 20,000	$0.07409	$0.00135	$0.00000	**$0.07544**
Next 200,000	$0.05799	$0.00135	$0.00000	**$0.05934**
All Additional	$0.02942	$0.00135	$0.00000	**$0.03077**

Minimum Charge:

The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

* The rates shown in this Rate Schedule may not always reflect actual billing rates. See the corresponding rate schedules for the actual rates.

(continued)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

PATRICK D. EHRBAR
Exhibit No. 902

Proposed Natural Gas Service Tariffs

SCHEDULE 410

GENERAL RESIDENTIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to residential natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	**$10.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.61897	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069	
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)	
Schedule 476 – Intervenor Funding	$0.00150	
Schedule 478 – DSM Cost Recovery	$0.01789	
Schedule 493 – Low Income Rate Assistance Program	$0.00451	
Schedule 497 – Capital Cost Recovery	$0.00000	
Total Billing Rate *	**$1.26229**	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	**$20.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.51770	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069	
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)	
Schedule 478 – DSM Cost Recovery	$0.01789	
Schedule 497 – Capital Cost Recovery	$0.00000	
Total Billing Rate *	**$1.15501**	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	**$50.00**	
Commodity Charge Per Therm:		
Base Rate	$0.12842	(R)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069	
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)	
Schedule 478 – DSM Cost Recovery	$0.01789	
Schedule 497 – Capital Cost Recovery	$0.00000	
Total Billing Rate *	**$0.76573**	(R)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Commodity Charge Per Therm:	
Base Rate	$0.11652
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.41155
Schedule 462 – Gas Cost Rate Adjustment	$0.05099
Schedule 476 – Intervenor Funding	$0.00135
Schedule 497 – Capital Cost Recovery	$0.00000
Total Billing Rate *	**$0.58041**

Annual Minimum Charge:

Each Customer shall be subject to an Annual Minimum Charge if their gas usage during the prior year does not equal or exceed 50,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 11.652 cents per therm.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

Kelly Norwood

AVISTA CORPORATION
Dba Avista Utilities

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:		
Base Rate	$0.15954	(R)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.62069	
Schedule 462 – Gas Cost Rate Adjustment	($0.00127)	
Schedule 478 – DSM Cost Recovery	$0.01789	
Schedule 497 – Capital Cost Recovery	$0.00000	
Total Billing Rate *	**$0.79685**	(R)

Minimum Charge:
$5,810.92 per season.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	**$275.00**

Volumetric Charge Per Therm:

	Base Rate	Schedule 476	Schedule 497	Billing Rate*
First 10,000	$0.13889(R)	$0.00135	$0.00000	**$0.14024(R)**
Next 20,000	$0.08359(R)	$0.00135	$0.00000	**$0.08494(R)**
Next 20,000	$0.06870(R)	$0.00135	$0.00000	**$0.07005(R)**
Next 200,000	$0.05377(R)	$0.00135	$0.00000	**$0.05512(R)**
All Additional	$0.02728(R)	$0.00135	$0.00000	**$0.02863(R)**

Minimum Charge:

The minimum monthly charge shall be $1,567.31 per month, accumulative annually. (I)

* The rates shown in this Rate Schedule may not always reflect actual billing rates. See the corresponding rate schedules for the actual rates.

(continued)

SCHEDULE 475
DECOUPLING MECHANISM – NATURAL GAS

(N)

PURPOSE:

This Schedule establishes balancing accounts and implements an annual rate adjustment mechanism that decouples or separates the recovery of the Company's Commission authorized revenues from the therm sales to customers served under the applicable natural gas service schedules.

APPLICABLE:

To Customers in the State of Oregon where the Company has natural gas service available. This schedule shall be applicable to all retail customers taking service under Schedules 410, 420, 424, 440, and 444. This Schedule does not apply to Schedule 447 (Special Contract Natural Gas Service) or Schedule 456 (Interruptible Transportation Service For Customer-Owned Gas). Applicable Customers will be segregated into two (2) distinct Rate Groups:

Group 1 – Schedule 410
Group 2 – Schedules 420, 424, 440 and 444

MONTHLY RATE:

Group 1 – $0.00000 per therm
Group 2 – $0.00000 per therm

DESCRIPTION OF THE NATURAL GAS DECOUPLING MECHANISM:

Calculation of Monthly Allowed Delivery Revenue Per Customer:

Step 1 – Determine the Total Delivery Revenue - The Total Normalized Revenue is equal to the final approved base rate revenue approved in the Company's last general rate case, individually for each Rate Schedule.

(N)

(N)

SCHEDULE 475A
DECOUPLING MECHANISM – NATURAL GAS

Step 2 – Remove Basic Charge Revenue – included in Total Delivery Revenue is revenue recovered from customers in Basic and Minimum charges ("Basic Charges"). Because the decoupling mechanism only tracks revenue that varies with customer energy usage, the revenue from Basic Charges is removed. The number of Customer Bills in the test period, multiplied by the applicable Fixed Charges determines the total Basic Charge revenue by rate schedule.

Step 3 – Determine Allowed Decoupled Revenue – Allowed Decoupled Revenue is equal to the Delivery Revenue (Step 1) minus the Basic Charge Revenue (Step 2).

Step 4 – Determine the Allowed Decoupled Revenue per Customer – To determine the annual per customer Allowed Decoupled Revenue, divide the Allowed Decoupled Revenue (by Rate Group) by the Rate Year number of Customers (by Rate Group) to determine the annual Allowed Decoupled Revenue per Customer (by Rate Group).

Step 5 – Determine the Monthly Allowed Decoupled Revenue per Customer - to determine the monthly Allowed Decoupled Revenue per Customer, the annual Allowed Decoupled Revenue per Customer is shaped based on the monthly therm usage from the rate year. The mechanism uses the resulting monthly percentage of usage by month and multiplied that by the annual Allowed Decoupled Revenue per Customer to determine the 12 monthly values.

Calculation of Monthly Decoupling Deferral:

Step 1 – Determine the actual number of customers each month.

Step 2 – Multiply the actual number of customers by the applicable monthly Allowed Decoupled Revenue per Customer. The result of this calculation is the total Allowed Decoupled Revenue for the applicable month.

Step 3 – Determine the actual revenue collected in the applicable month.

Step 4 – Calculate the amount of fixed charge revenues included in total actual monthly revenues.

(N)

(N)

SCHEDULE 475B
DECOUPLING MECHANISM – NATURAL GAS

Step 5 – Subtract the basic charge revenue (Step 4) from the total actual monthly revenue (Step 3). The result is the Actual Decoupled Revenue.

Step 6 – The difference between the Actual Decoupled Revenue (Step 5) and the Allowed Decoupled Revenue (Step 2) is calculated, and the resulting balance is deferred by the Company Interest would accrue on deferrals at the Company's authorized rate of return.

ANNUAL NATURAL GAS DECOUPLING RATE ADJUSTMENT:

On or before August 1st each year, the Company will file a request with the Commission to surcharge or rebate, by Rate Group, the amount accumulated in the deferred revenue accounts for the prior January through December time period. The proposed tariff revisions included with that filing would include a rate adjustment that recovers/rebates the appropriate deferred revenue amount over a twelve-month period effective on November 1st.

The deferred revenue amount approved for recovery or rebate would be transferred to a balancing account and the revenue surcharged or rebated during the period would reduce the deferred revenue in the balancing account. Any deferred revenue remaining in the balancing account at the end of the calendar year would be added to the new revenue deferrals to determine the amount of the proposed surcharge/rebate for the following year.

After determining the amount of deferred revenue that can be recovered through a surcharge (or refunded through a rebate) by Rate Group, the proposed rates under this Schedule will be determined by dividing the deferred revenue to be recovered by Rate Group by the estimated therm sales for each Rate Group during the twelve month recovery period. The deferred revenue amount to be recovered will be transferred to a Decoupling Balancing Account and the actual revenue received under this Schedule will be applied to the Account to reduce (amortize) the balance. Interest would accrue on deferrals at the Company's authorized rate of return, similar to other Company deferrals. Once a deferral balance is approved for amortization, interest will accrue at the Modified Blended Treasury Rate, similar to other Company amortizations.

(N)

(N)

SCHEDULE 475C
DECOUPLING MECHANISM – NATURAL GAS

3% ANNUAL DECOUPLING RATE INCREASE LIMITATION:

The amount of the incremental proposed rate adjustment under this Schedule cannot reflect more than a 3% rate increase. This will be determined by dividing the incremental annual revenue to be collected (proposed surcharge revenue less present surcharge revenue) under this Schedule by the total "normalized" revenue for the two Rate Groups for the most recent January through December time period. Normalized revenue is determined by multiplying the weather-corrected usage for the period by the present billing rates in effect. If the incremental amount of the proposed surcharge exceeds 3%, only a 3% incremental rate increase will be proposed and any remaining deferred revenue will be carried over to the following year. There is no limit to the level of the decoupling rebate.

(N)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

PATRICK D. EHRBAR
Exhibit No. 903

Rate Spread & Rate Design

Avista Utilities
State of Oregon
Comparison of Natural Gas Usage
2013-2014 Weather-Normalized Actuals, and 2015-2016 Forecast

Line No.		Actual Calendar Usage	Weather Adj.	Normalized Usage	Avg. Customers	Annual Use/ Customer	Monthly Use/ Customer
	Residential Sch 410						
1	2013	51,201,567	(2,945,968)	48,255,599	85,137	566.8	47.2
2	2014	42,039,996	5,671,120	47,711,116	85,789	556.1	46.3
3	2015	49,097,140		49,097,140	86,298	568.9	47.4
4	2016	49,018,942		49,018,942	87,065	563.0	46.9
5							
6	**Commercial Sch 420**						
7	2013	27,592,098	(1,710,546)	25,881,552	11,190	2,313	193
8	2014	23,367,291	2,967,838	26,335,129	11,281	2,334	195
9	2015	26,450,079		26,450,079	11,333	2,334	194
10	2016	26,621,408		26,621,408	11,416	2,332	194
11							
12							
13	**Large Sales Schs. 424, 440 & 444**						
14	2013	8,026,949	(73,300)	7,953,649	117	67,980	5,665
15	2014	8,065,335	109,530	8,174,865	115	70,932	5,911
16	2015	8,637,435		8,637,435	119	72,670	6,056
17	2016	8,821,802		8,821,802	121	72,983	6,082
18							
19							
20	**Total Sales Volumes**						
21	2013			82,090,800	96,444		
22	2014			82,221,110	97,186		
23	2015			84,184,654	97,750		
24	2016			84,462,152	98,602		
25							
26							
27	**Transport Schs. 447 & 456**						
28	2013	38,821,540		38,821,540	39	989,084	82,424
29	2014	42,649,341		42,649,341	39	1,084,305	90,359
30	2015	44,606,372		44,606,372	38	1,172,642	97,720
31	2016	47,119,020		47,119,020	38	1,238,715	103,226
32							
33							
34	**Total Throughput**						
35	2013			120,912,340			
36	2014			124,870,451			
37	2015			128,791,025			
38	2016			131,581,173			

Avista Utilities
Oregon - Natural Gas
Pro Forma 12 Months Ended December 31, 2016

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
1	CURRENT REVENUE	$ 53,224,000	34,864,000	13,605,000	687,000	463,000	44,000	231,000	3,330,000
2	COST OF GAS	$ -	-	-	-	-	-	$ -	$ -
3	CURRENT DISTRIBUTION MARGIN	$ 53,224,000	$ 34,864,000	$ 13,605,000	$ 687,000	$ 463,000	$ 44,000	$ 231,000	$ 3,330,000
4	% of Current Margin excl Sch 447	100.00%	65.79%	25.67%	1.30%	0.87%	0.08%		6.28%
5	Total Revenue Requirement	$ 8,557,000							
6	Revenue Requirement as a Percent of Margin Revenue	16.08%							
7	Percentage Applied to Overall Margin Increase		105.69%	133.36%	-43.54%	0.00%	-43.54%		-43.54%
8	Increase as a Percent of Total Current Margin		16.99%	21.44%	-7.00%	0.00%	-7.00%		-7.00%
9	**PROPOSED MARGIN REVENUE INCREASE**	**$ 8,557,000**	**$ 5,924,357**	**$ 2,916,913**	**$ (48,090)**	**$ -**	**$ (3,080)**		**$ (233,100)**
10	**Percentage Distribution Revenue Increase**	**16.08%**	**16.99%**	**21.44%**	**-7.00%**	**0.00%**	**-7.00%**		**-7.00%**
	Cost of Service								
11	Proposed Margin	$ 61,781,000	$ 40,788,357	$ 16,521,913	$ 638,910	$ 463,000	$ 40,920	$ 231,000	$ 3,096,900
12	LRIC Based Target Margin (Line 25 of Miller Exhibit 801 Page 1 of 3)	**$ 61,781,000**	**41,104,746**	**17,205,725**	**446,794**	**366,419**	**28,919**	**295,284**	**2,333,113**
13	**Relative Margin to Cost at Present Rates (Line 27 of Miller Exhibit 801 Page 1 of 3)**	**1.00**	**0.98**	**0.92**	**1.78**	**1.47**	**1.77**	**0.91**	**1.66**
14	**Relative Margin to Cost at Proposed Rates**	**1.00**	**0.99**	**0.96**	**1.43**	**1.26**	**1.41**		**1.33**
15	Movement Towards Unity		50%	52%	45%	44%	46%		50%
16	Billed Revenue	$ 106,712,588	$ 66,399,086	$ 30,571,084	$ 3,611,032	$ 2,307,143	$ 209,089	$ 231,000	$ 3,384,154
17	Percentage Billed Revenue Increase	**8.0%**	**8.9%**	**9.5%**	**-1.3%**	**0.0%**	**-1.5%**	**0.0%**	**-6.9%**

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2016
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Distribution Revenue Under Present Rates	Proposed GRC Increase	Distribution Revenue Under Proposed Rates	Therms (000s)	**Distribution Revenue Percentage Increase**	Billed Revenue Under Present Rates	Proposed GRC Increase	Billed Revenue Under Proposed Rates	**Billed Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential	410	$34,864	$5,924	$40,788	49,019	**17.0%**	$66,399	$5,924	$72,323	**8.9%**
2	General Service	420	13,605	2,917	16,522	26,621	**21.4%**	30,571	$2,917	$33,488	**9.5%**
3	Large General Service	424	687	(48)	639	4,588	**-7.0%**	3,611	($48)	$3,563	**-1.3%**
4	Interruptible Service	440	463	0	463	3,975	**0.0%**	2,307	$0	$2,307	**0.0%**
5	Seasonal Service	444	44	(3)	41	258	**-7.0%**	209	($3)	$206	**-1.5%**
6	Transportation Service	456	3,330	(233)	3,097	39,792	**-7.0%**	3,384	($233)	$3,151	**-6.9%**
7	Special Contract	447	231	0	231	7,327	**0.0%**	231	$0	$231	**0.0%**
8	Total		$53,224	$8,557	$61,781	131,581	**16.1%**	$106,712	$8,557	$115,269	**8.0%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Base Rates	Change	Proposed Base Rates
Residential Service Schedule 410		
$8.00 Customer Charge	$2.00/month	$10.00 Customer Charge
All Therms - $0.54073/Therm	$0.07824/therm	All Therms - $0.61897/Therm
General Service Schedule 420		
$14.00 Customer Charge	$6.00/month	$20.00 Customer Charge
All Therms - $0.43901/Therm	$0.07869/therm	All Therms - $0.51770/Therm
Large General Service Schedule 424		
$50.00 Customer Charge	$0.00/month	$50.00 Customer Charge
All Therms - $0.13887/Therm	-$0.01045/therm	All Therms - $0.12842/Therm
Interruptible Service Schedule 440		
All Therms - $0.11652/Therm	$0.00000/therm	All Therms - $0.11652/Therm
Seasonal Service Schedule 444		
All Therms - $0.17155/Therm	-$0.01201/therm	All Therms - $0.15954/Therm
Transportation Service Schedule 456		
$275.00 Customer Charge	$0.00/month	$275.00 Customer Charge
1st 10,000 Therms - $0.14978/Therm	-$0.01089/therm	1st 10,000 Therms - $0.13889/Therm
Next 20,000 Therms - $0.09014/Therm	-$0.00655/therm	Next 20,000 Therms - $0.08359/Therm
Next 20,000 Therms - $0.07409/Therm	-$0.00539/therm	Next 20,000 Therms - $0.06870/Therm
Next 200,000 Therms - $0.05799/Therm	-$0.00422/therm	Next 200,000 Therms - $0.05377/Therm
Over 250,000 Therms - $0.02942/Therm	-$0.00214/therm	Over 250,000 Therms - $0.02728/Therm
		Schedule 456 Monthly Minimum Charge 18,750 @ $0.08359 = $1,567.31

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

PATRICK D. EHRBAR
Exhibit No. 904

Natural Gas Decoupling Mechanism

Avista Utilities
Natural Gas Decoupling Mechanism (Oregon)
Development of Decoupled Revenue by Rate Schedule - Natural Gas

	TOTAL	RESIDENTIAL SCHEDULE 410	SM COMMERCIAL & INDUSTRIAL SCH. 420	LG COMMERCIAL & INDUSTRIAL SCH. 424	INTERRUPTIBLE SCH 440	INTERRUPTIBLE SCH 444	TRANSPORTATION SCH 456
1 Total Normalized 2016 Margin Revenue	$ 52,993,000	$ 34,864,000	$ 13,605,000	$ 687,000	$ 463,000	$ 44,000	$ 3,330,000
2 Proposed Margin Revenue Increase	$ 8,557,000	$ 5,924,000	$ 2,917,000	$ (48,000)	$ -	$ (3,000)	$ (233,000)
3 Total Delivery Revenue (2016 Test Year) (Ln 1 + Ln 2)	$ 61,550,000	$ 40,788,000	$ 16,522,000	$ 639,000	$ 463,000	$ 41,000	$ 3,097,000
4 Customer Bills (2016 Test Year)	1,183,654	1,044,776	136,995	994	416	41	432
5 Proposed Basic Charges		$10.00	$20.00	$50.00	$0.00	$0.00	$275.00
6 Basic Charge Revenue (Ln 4 * Ln 5)	$ 13,356,143	$ 10,447,765	$ 2,739,902	$ 49,677	$ -	$ -	$ 118,800
7 Decoupled Revenue (Ln 6 - Ln 3)	$ 48,193,857	$ 30,340,235	$ 13,782,098	$ 589,323	$ 463,000	$ 41,000	$ 2,978,200
8 Normalized Therms (2016 Test Year)	124,253,684	49,018,942	26,621,408	4,588,281	3,975,023	258,498	39,791,532
		Residential	Non-Residential Group				Exempt from
9 Average Number of Customers (Line 8 / 12 mos.)		87,065	11,537				Decoupling
10 Annual Therms		49,018,942	35,443,210				Mechanism
11 Basic Charge Revenues		$ 10,447,765	$ 2,789,579				
12 Customer Bills		1,044,776	138,446				
13 Average Basic Charge		$10.00	$20.15				

Avista Utilities
Natural Gas Decoupling Mechanism (Oregon)
Development of Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Residential	Non-Residential Schedules*
	(a)	(b)	(c)	(d)
1	Decoupled Revenue	Page 1	$ 30,340,235	$ 14,875,421
2	Test Year Number of Customers 2016	Revenue Data	87,065	11,537
3	Decoupled Revenue Per Customer	(1) / (2)	$ 348.48	$ 1,289.35

*Schedules 420, 424, 440, and 444

Avista Utilities
Natural Gas Decoupling Mechanism (Oregon)
Development of Monthly Decoupled Revenue Per Customer - Natural Gas

Line No.		Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1															
2	**Natural Gas Delivery Volume**														
3	*Residential*														
4	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	8,259,327	6,606,405	5,747,901	4,165,040	2,410,745	1,523,490	1,258,638	1,142,055	1,096,063	2,692,488	5,533,111	8,583,678	49,018,942
5	- % of Annual Total	% of Total	16.85%	13.48%	11.73%	8.50%	4.92%	3.11%	2.57%	2.33%	2.24%	5.49%	11.29%	17.51%	100.00%
6															
7	*Non-Residential Sales**														
8	- Weather-Normalized Therm Delivery Volume	Monthly Rate Year	8,696,182	7,540,793	7,072,682	5,963,662	4,825,382	4,321,605	4,241,771	4,462,578	4,728,941	6,008,025	7,254,849	8,787,005	73,903,474
9	- % of Annual Total	% of Total	11.77%	10.20%	9.57%	8.07%	6.53%	5.85%	5.74%	6.04%	6.40%	8.13%	9.82%	11.89%	100.00%
10															
11	**Monthly Decoupled Revenue Per Customer ("RPC")**														
12	*Residential*														
13	- 2015 Decoupled Revenue per Customer	Page 2 - Decoupled RPC													$ 348.48
14	- 2015 Monthly Decoupled Revenue per Customer	(5) x (13)	$ 58.72	$ 46.97	$ 40.86	$ 29.61	$ 17.14	$ 10.83	$ 8.95	$ 8.12	$ 7.79	$ 19.14	$ 39.34	$ 61.02	$ 348.48
15															
16	*Non-Residential Sales**														
17	- 2015 Decoupled Revenue per Customer	Page 2 - Decoupled RPC													$ 1,289.35
18	- 2015 Monthly Decoupled Revenue per Customer	(9) x (17)	$ 151.72	$ 131.56	$ 123.39	$ 104.04	$ 84.19	$ 75.40	$ 74.00	$ 77.86	$ 82.50	$ 104.82	$ 126.57	$ 153.30	$ 1,289.35
19															
20	*Schedules 420, 424, 440, and 444.														

Avista Utilities
Natural Gas Decoupling Mechanism (Oregon)
Development of Natural Gas Deferrals (Calendar Year 2016)

Line No.		**Source**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Residential Group													
1	Actual Customers	Illustrative	88,000	88,100	88,200	88,300	88,400	88,500	88,600	88,700	88,800	88,900	89,000	89,100
2	Monthly Decoupled Revenue Per Customer	Page 3	$ 58.72	$ 46.97	$ 40.86	$ 29.61	$ 17.14	$ 10.83	$ 8.95	$ 8.12	$ 7.79	$ 19.14	$ 39.34	$ 61.02
3	Allowed Decoupled Revenue	(1) x (2)	$ 5,167,033	$ 4,137,662	$ 3,604,058	$ 2,614,531	$ 1,515,017	$ 958,510	$ 792,772	$ 720,153	$ 691,930	$ 1,701,647	$ 3,500,849	$ 5,437,072
4	Actual Monthly Delivery Revenue	Illustrative	$ 6,000,000	$ 5,100,000	$ 4,300,000	$ 3,600,000	$ 2,475,000	$ 1,800,000	$ 1,600,000	$ 1,600,000	$ 1,600,000	$ 2,600,000	$ 4,400,000	$ 6,300,000
5	Actual Fixed Charge Revenue	Illustrative	$ 880,000	$ 881,000	$ 882,000	$ 883,000	$ 884,000	$ 885,000	$ 886,000	$ 887,000	$ 888,000	$ 889,000	$ 890,000	$ 891,000
6	Actual Decoupled Revenue	(4) - (5)	$ 5,120,000	$ 4,219,000	$ 3,418,000	$ 2,717,000	$ 1,591,000	$ 915,000	$ 714,000	$ 713,000	$ 712,000	$ 1,711,000	$ 3,510,000	$ 5,409,000
7	Deferral - Surcharge (Rebate)	(3) - (6)	$ 47,033	$ (81,338)	$ 186,058	$ (102,469)	$ (75,983)	$ 43,510	$ 78,772	$ 7,153	$ (20,070)	$ (9,353)	$ (9,151)	$ 28,072
8	Interest on Deferral	Auth ROR 7.516%	$ 147	$ 41	$ 369	$ 633	$ 78	$ (23)	$ 360	$ 631	$ 595	$ 506	$ 451	$ 514
9	Cumulative Deferral	Σ((7) + (8))	$ 47,180	$ (34,116)	$ 152,310	$ 50,474	$ (25,430)	$ 18,057	$ 97,189	$ 104,973	$ 85,498	$ 76,651	$ 67,952	$ 96,537
	Non-Residential Group													
10	Actual Customers	Illustrative	11,600	11,610	11,620	11,630	11,640	11,650	11,660	11,670	11,680	11,690	11,700	11,705
11	Monthly Decoupled Revenue Per Customer	MV	$ 151.72	$ 131.56	$ 123.39	$ 104.04	$ 84.19	$ 75.40	$ 74.00	$ 77.86	$ 82.50	$ 104.82	$ 126.57	$ 153.30
12	Allowed Decoupled Revenue	(10) x (11)	$ 1,759,919	$ 1,527,408	$ 1,433,825	$ 1,210,037	$ 979,920	$ 878,369	$ 862,883	$ 908,579	$ 963,635	$ 1,225,328	$ 1,480,881	$ 1,794,396
13	Actual Monthly Delivery Revenue	Illustrative	$ 2,000,000	$ 1,750,000	$ 1,680,000	$ 1,500,000	$ 1,200,000	$ 1,050,000	$ 1,100,000	$ 1,150,000	$ 1,200,000	$ 1,475,000	$ 1,725,000	$ 2,100,000
14	Actual Fixed Charge Revenue	Illustrative	$ 233,732	$ 233,933	$ 234,135	$ 234,336	$ 234,538	$ 234,739	$ 234,941	$ 235,142	$ 235,344	$ 235,545	$ 235,747	$ 235,847
15	Actual Decoupled Revenue	(13) - (14)	$ 1,766,268	$ 1,516,067	$ 1,445,865	$ 1,265,664	$ 965,462	$ 815,261	$ 865,059	$ 914,858	$ 964,656	$ 1,239,455	$ 1,489,253	$ 1,864,153
16	Deferral - Surcharge (Rebate)	(12) - (15)	$ (6,350)	$ 11,342	$ (12,040)	$ (55,627)	$ 14,458	$ 63,108	$ (2,177)	$ (6,279)	$ (1,021)	$ (14,127)	$ (8,372)	$ (69,757)
17	Interest on Deferral	Auth ROR 7.516%	$ (20)	$ (4)	$ (7)	$ (219)	$ (349)	$ (108)	$ 82	$ 56	$ 34	$ (14)	$ (84)	$ (329)
18	Cumulative Deferral	Σ((16) + (17))	$ (6,370)	$ 4,968	$ (7,079)	$ (62,924)	$ (48,815)	$ 14,184	$ 12,090	$ 5,867	$ 4,879	$ (9,262)	$ (17,718)	$ (87,805)