Avista Corp.
1411 East Mission PO Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500
Toll Free 800-727-9170

AVISTA Corp.

October 12, 2007

Public Utility Commission of Oregon
Attn: Filing Center
PO Box 2148
Salem, OR 97308-2148

RE: Request for General Rate Revision of Avista Corporation

In accordance with Oregon Administrative Rules, Avista Corp., dba Avista Utilities, respectfully submits an original and 20 copies of the Company's trial brief, testimony and associated exhibits in support of its request for a general rate revision. Five (5) copies of work papers supporting testimony and exhibits have also been included for all Company witnesses, excluding witness Mr. Avera. Mr. Avera's work papers will be provided as soon as possible.

Please direct any questions regarding this filing to Liz Andrews at (509) 495-8601.

Sincerely,

Kelly Norwood

Kelly O. Norwood
Vice President, State and Federal Regulation

Enclosure

c: See attached service list

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served Direct Testimony and Exhibits in the Oregon Natural Gas General Rate Case Filing of Avista Utilities', a division of Avista Corporation, upon the parties listed below by mailing a copy thereof, postage prepaid and/or by electronic mail.

Mr. Edward Finklea
Cable Huston Benedict
Haagensen & Lloyd, LLP
1001 SW 5th, Suite 2000
Portland, OR 97204-1136
efinklea@chbh.com

Citizens' Utilities Board
610 SW Broadway, Suite 308
Portland, OR 97205-3404
Jason@OregonCUB.org
Bob@OregonCUB.org
Lowrey@OregonCUB.org

Ms. Paula Pyron
Executive Director
Northwest Industrial Gas Users
4113 Wolfberry Court
Lake Oswego, OR 97035
ppyron@nwigu.org

I declare under penalty of perjury that the foregoing is true and correct.

Dated at Spokane, Washington this 11th day of October 2007.

Patty Olsness

Patty Olsness
Rates Coordinator

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG-___

In the matter of the Application of AVISTA CORPORATION, DBA AVISTA UTILITIES for a General Rate Revision	))))	TRIAL BRIEF OF AVISTA CORPORATION

Avista Corporation, doing business as Avista Utilities, ("Avista" or "Company") is filing tariff schedules, pursuant to ORS 757.205 and ORS 757.220, to effect a general revision for its natural gas customers in Oregon.

1.

Avista provides natural gas service in Oregon and is a public utility subject to the Commission's jurisdiction under ORS 757.005(1)(a)(A). Avista provides natural gas distribution service in southwestern and northeastern Oregon. The Company also provides electric and natural gas service within a 26,000 square mile area of eastern Washington and northern Idaho. During 2006, Avista supplied retail electric service to an average of approximately 346,000 customers and retail natural gas service to approximately 306,000 customers, including approximately 94,000 customers in Oregon who will be affected by the proposed rate revision. Avista's principal place of business is located in Spokane, Washington.

2.

Avista requests that all notices, pleadings, and correspondence regarding this filing be sent to the following:

David J. Meyer, Esq.
Chief Counsel for Regulatory and Governmental Affairs
Avista Corporation
P.O. Box 3727
1411 E. Mission Avenue, MSC-13
Spokane, Washington 99220-3727
Telephone: (509) 495-4316
Facsimile: (509) 495-8851
E-mail: david.meyer@avistacorp.com

Kelly Norwood
Vice President, State and Federal Regulation
Avista Corporation
P.O. Box 3727
1411 E. Mission Avenue, MSC-13
Spokane, Washington 99220-3727
Telephone: (509) 495-4267
Facsimile: (509) 495-8851
E-mail: kelly.norwood@avistacorp.com

3.

The test year for the proposed rate revision is the historical twelve-month period beginning January 1, 2006 and ending December 31, 2006. The Company's pro forma results of operations for the test period indicate that, at the current rate levels, Avista would earn a return on equity ("ROE") of 7.06 percent. This ROE is clearly not sufficient to provide Avista with a fair and reasonable return or allow the Company to attract capital at reasonable rates.

Avista's revised tariff schedules effect an increase in rates for Oregon retail customers of $2,975,000, or 2.3 percent, which would produce an overall rate of return of 8.98 percent and a return on equity of 11.00 percent. Pursuant to ORS 757.220, the revised schedules contain an effective date of November 21, 2007.

4.

The Company acquired its Oregon natural gas operations from CP National in 1991. In the past 15 years that Avista has operated these properties, its base rates have previously increased by only a net of 4.36%. A combination of capital additions, declining margins and increases in general business expense now requires the Company to request an increase in overall base retail rates of $2,975,000.

The Company used the results of a long-run incremental cost study as a guide in the proposed spread of the requested increase to the various customer rate schedules. This study indicates that at current rates, residential customers are in line with cost of service, small commercial customers are paying less than their cost of service, while all other customer groups exceed their cost of service to varying degrees. Therefore, the proposed rate spread would result in an increase of 2.6% to residential customers, a decrease of 15.1% to the seasonal rate schedule, and increases ranging between 1.3% and 9.4% to other rate schedules.

5.

Avista's direct case consists of the testimony and exhibits of the following witnesses:

(a) Policy. **Scott L. Morris**, President of Avista Utilities and Chief Operating Officer of Avista Corporation, presents an overview of the filing and identifies the cost increases that make this filing necessary. Mr. Morris provides a history of the Company's general rate changes in Oregon, describes efforts to reduce operating costs, and explains the Company's customer support programs that are in place to assist customers.

(b) Cost of Capital and Financing Issues. **Malyn K. Malquist**, Executive Vice President and Chief Financial Officer will address the Company's capital structure, the proposed cost of embedded debt and preferred stock and the overall rate of return. He will explain the actions the Company has taken to acquire needed capital and mitigate the ongoing financial concerns.

(c) Return on Equity and Capital Structure. **William E. Avera**, as a principal in 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 an 11.00% return on equity.

(d) Gas Supply, Storage and Pro Formed Capital Projects. **Kevin J. Christie**, Director of Gas Supply, will discuss the pro formed capital additions included in this filing. In addition, he will also discuss the Jackson Prairie Expansion Project.

(e) Revenue Requirements. **Elizabeth M. Andrews,** Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposal. Her testimony and exhibits will cover accounting and financial data in support of the Company's need for the proposed increase in rates and allocation methodologies. She will also explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base.

(f) Long-Run Incremental Costs. **Tara L. Knox**,Senior Rate Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Ms. Knox discusses her study results and how each schedule's present and proposed margin compares to the indicated cost. Ms. Knox also discusses the weather normalization usage adjustment methodology.

(g) Rate Design and Rate Spread. **Brian J. Hirschkorn**, Manager, Retail Pricing, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. In addition, he will also address the Company's revenue normalization adjustment.

6.

The following exhibits are attached pursuant to OAR 860-13-0075:

(a) Exhibit A. The information required by OAR 860-013-0075(1)(b)(A)-(F).

(b) Exhibit B. From Ms. Andrew's Exhibit 401, page 1, which shows the results of operations for Avista's Oregon jurisdiction before and after the proposed rate change, as required by OAR 860-013-0075(1)(b)(G).

(c) Exhibit C. This exhibit shows the effect of the proposed rate change on each class of customers as required by OAR 860-013-0075(1)(b)(H). Exhibit C also contains information required by OAR 860-022-0030(1). Specifically, the exhibit shows, for each tariff schedule, the total number of customers affected, the total annual revenue derived under the existing schedule, and the amount of estimated revenue derived from applying the proposed rate revisions. For each tariff schedule, the exhibit also shows the average monthly use and resulting bills under both existing rates and proposed rates for characteristic customers.

7.

Avista Corporation respectfully requests that the Commission issue an order granting the rate relief requested in this filing and approving the proposed tariff schedules.

DATED: October 12, 2007.

David J. Meyer
Chief Counsel for Regulatory and Governmental Affairs
Avista Corporation

EXHIBIT A

INFORMATION REQUIRED BY OAR 860-013-0075(1)(b)(A)-(F)

A. The dollar amount of total revenues that would be collected under the proposed rates is $130,389,000.

B. The dollar amount of revenue change requested is $2,975,000.

C. The percentage change in revenues requested is 2.3 percent.

D. The test period proposed is January 1, 2006 to December 31, 2006.

E. The requested overall rate of return is 8.98 percent and the requested return on equity is 11.00 percent.

F. The rate base proposed in this filing is $92,572,000.

EXHIBIT B

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION INCREASED REVENUE REQUIREMENT
TWELVE MONTHS ENDED DECEMBER 31, 2006
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	**DESCRIPTION**	**Actual Per Results Report**	**Total Adjustments**	**Pro Forma Total**	**Proposed Revenues & Related Exp**	**Pro Forma Proposed Total**
	a	*b*	*c*	*d*	*e*	*f*
	OPERATING REVENUES					
1	Total General Business	$122,020	$2,514	$124,534	$2,975	$127,509
2	Total Transportation	2,558	322	2,880		2,880
3	Other Revenues	44,300	(44,187)	113		113
4	Total Operating Revenues	168,878	(41,351)	127,527	2,975	130,502
	OPERATING EXPENSES					
5	Gas Purchased	133,761	(38,430)	95,331		95,331
6	Operation and Maintenance	9,100	(226)	8,874	16	8,890
7	Administration & General	5,847	61	5,908	8	5,916
8	Taxes Other than Income	5,450	(1,399)	4,051	59	4,110
9	Depreciation & Amortization	8,139		3,933		3,933
10	Total Operating Expenses	162,297	(39,994)	118,097	83	118,180
11	OPERATING INCOME BEFORE FIT	6,581	(1,357)	9,430	2,892	12,322
	INCOME TAXES					
12	Current Federal Income Taxes	2,721	443	3,164	1,007	4,171
13	Deferred Federal Income Taxes	(1,366)	676	(690)		(690)
14	State Income Taxes	303	210	513	14	527
15	Total Income Taxes	1,658	1,329	2,987	1,021	4,008
						0
16	NET OPERATING INCOME	$4,923	($2,686)	$6,443	$1,871	$8,314
	AVERAGE RATE BASE					
17	Utility Plant in Service	174,441	9,494	183,935		183,935
18	Less: Accum Depr and Amort	(77,663)	1,465	(76,198)	0	(76,198)
19	Net Utility Plant	96,778	10,959	107,737	0	107,737
20	Accumulated Deferred FIT	(18,736)	2,600	(16,136)		(16,136)
21	Inventory and Other	971	0	971	0	971
22	TOTAL AVERAGE RATE BASE	$79,013	$13,559	$92,572	$0	$92,572
23	RATE OF RETURN	6.23%		6.96%		8.98%
24	RETURN ON EQUITY	5.63%		7.06%		11.00%

EXHIBIT C

Avista Utilities
Docket No. UG-___
Rate Spread Summary
Oregon - Gas
12 Months Ended December 31, 2006

Type of Service	Schedule Number	Avg. No. of Customers	Annual Therms	Avg. Use per Customer per Month	Revenue Under Pres. Rates	Avg. Bill Under Pres. Rates	Revenue Percentage Increase	Revenue Increase	Avg. Increase per Customer per Month	Revenue Under Prop. Rates	Avg. Bill Under Prop. Rates
Residential	410	81,400	49,375,000	51	$76,444,000	$78.91	2.6%	$1,959,000	$2.02	$78,403,000	$80.93
General Service	420	10,800	28,349,000	219	39,490,000	$305.06	1.8%	$711,000	$5.49	40,201,000	$310.55
Large General Service	424	98	3,710,000	3,149	4,933,000	$4,187	1.4%	$71,000	$60	5,004,000	$4,248
Interruptible Service	440	21	3,355,000	13,313	3,423,000	$8,391	1.3%	$45,000	$108	3,468,000	$8,499
Seasonal Service	444	8	186,000	8,097	244,000	$10,598	-15.1%	-$37,000	-$1,601	207,000	$8,997
Transportation Service	456	36	35,312,000	81,741	2,404,000	$5,565	9.4%	$226,000	$524	2,630,000	$6,088
Special Contract	447	5	5,673,000	94,550	476,000	$7,935	0.0%	$0	$0	476,000	$7,935
Total		92,368	125,960,000		$127,414,000		2.3%	$2,975,000		$130,389,000	

EXHIBIT B

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION INCREASED REVENUE REQUIREMENT
TWELVE MONTHS ENDED DECEMBER 31, 2006
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
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22	TOTAL AVERAGE RATE BASE	$79,013	$13,559	$92,572	$0	$92,572
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24	RETURN ON EQUITY	5.63%		7.06%		11.00%

Exhibit 100
Morris

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF SCOTT L. MORRIS
REPRESENTING THE 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 President and Chief Operating 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 named to my present position. Effective January 1, 2008, I will assume the position of President, CEO, and Chairman of the Board of Avista Corporation.

During my time as general manager in Oregon, I was appointed by then-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 am testifying as the policy witness for the Company. I provide an overview of Avista Utilities' rate filing and overall utility operations and will summarize the major factors driving the Company's need for general rate relief. I will also discuss the Company's customer support programs that are in place to assist our customers. Finally, I 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, which includes a map of the total company service territories, and page 2, which includes a diagram of Avista's current corporate structure. These exhibits were prepared under my direction.

Q. Would you please provide an overview of Avista Utilities' request in this filing?

A. Yes. A combination of declining margins and increases in general business expenses and an increase in capital costs since 2002 requires the Company to request an overall increase in base retail rates of $2.975 million or 2.3%. This request is based on a proposed rate of return of 8.98%, with a capital structure of 51.15% common equity at a 11.0% return on equity. 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 witness Mr. Hirschkorn testifies to these rate spread issues.

Q. What are the major elements of the requested increase?

A. Although there are a number of increases and decreases in revenue, expense and rate base items, there are a few major components that drive the requested rate increase. The Company has five major capital projects that will be completed in Oregon and that have been pro formed into this filing:

- Glendale Conversion to Natural Gas;
- East Medford Reinforcement Project;
- Integrity Management Pipe Replacement Project;
- Roseburg Reinforcement Project; and
- Merlin Gate Station Project

Company witness Mr. Christie will discuss in detail these projects. A second component is an increase in general business expenses over the past four year period since general rates were last increased in 2003 using a 2002 test period. The average number of customers have increased by over 12%, from 82,246 in 2002 to 92,406 during 2006. During that time period O&M and A&G costs increased $2.4 million, or 28%. Between 2002 and 2006, gross utility plant increased $44.0 million, or 31.0%.

The Company has experienced an expanding customer base requiring new plant investment, while at the same time experiencing lower natural gas usage on a per customer basis. Company witness Ms. Andrews testifies to these and other factors in arriving at the Company's revenue requirement in this case.

Further, Company witness Mr. Malquist and Company witness Mr. Avera discuss in detail the Company's weighted cost of capital of 8.98%, derived from a requested return on equity of 11.0%. The Company's pro forma rate of return under present rates is 6.96%, which is well below what would be considered to be a reasonable rate of return.

Concurrent with this filing, Avista filed with this Commission a Petition seeking authorization to revise its book depreciation rates consistent with the results of a study recently undertaken by the Company. Accordingly, this general rate case filing includes a pro forma depreciation adjustment to reflect the decrease in gas depreciation expense due to the utilization of the new depreciation rates that result from the study, as discussed further by Ms. Andrews.

The requested depreciation rate changes are necessary to ensure that the Company applies appropriate book depreciation rates and recovers its regulatory asset over a reasonable period on a going-forward basis.

II. OVERVIEW OF AVISTA UTILITIES

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 26,000 square mile area of eastern Washington and northern Idaho. During 2006, Avista supplied retail electric service to an average of approximately 346,000 customers and retail natural gas service to approximately 306,000 customers. Maps showing the Company's natural gas Oregon service area and Avista's total natural gas and electric service areas are provided on page 1 of Exhibit No. 101.

As of December 31, 2006, Avista Utilities had total assets of approximately $2.9 billion, with retail revenues in 2006 of $416 million for natural gas and $554 million for electric operations. As of December 2006, the utility had 1,430 full-time employees.

Q. Please describe Avista Utilities' natural gas utility operations in Oregon.

A. Of the Company's 306,000 natural gas customers, approximately 92,400 are served in Oregon. The Company serves the Oregon areas of Medford, Klamath Falls, Roseburg, and LaGrande. Lumber and wood products manufacturing is the dominant industry in our Oregon service area. During 2006, Avista delivered approximately 475 million therms to its retail natural gas customers. Of this total, 126 million were delivered to Oregon customers. The mix of customers by rate schedule and their proportionate share of usage and revenues at present rates is summarized in the table below by rate schedule:

Rate Schedule	% Revenues	No. of Customers	% Therms Delivered
410 — Residential	60.0%	81,400	39.2%
420 — General Service	31.0%	10,800	22.5%
424 — Large General Service	3.8%	98	2.9%
440 — Interruptible	2.7%	21	2.7%
444 — Seasonal	0.2%	8	0.2%
456 — Transportation	1.9%	36	28.0%
447 — Special Contract	0.4%	5	4.5%

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

A. The Company continues to work diligently to operate what I believe is a very efficient utility. The Company has historically run its operations with attention to minimizing expense while providing quality service and a high level of customer satisfaction. I will touch on some of our more recent efficiency improvements later in my testimony, such as our advanced meter reading program and mobile dispatch.

In 2007, the Company continues to be below investment grade, but it continues to make good progress toward regaining its investment grade credit rating. Timely rate relief through this filing is another important element in that continuing progress. Company witness Mr. Malquist will further discuss the actions taken by the Company to improve cash flow, reduce debt, and make progress toward regaining an investment grade credit rating.

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, low-cost utility business by delivering efficient, reliable and high quality service, at a reasonable price, to our customers and the communities we serve. We are fortunate to have dedicated employees who, despite the challenges of recent years, have maintained high morale and high customer satisfaction.

Q. What has been the Company's recent experience with performance indicators?

A. Customer service levels have remained very high. Avista Utilities routinely surveys customers seeking information on a variety of attributes including overall quality of work performed and overall satisfaction. On virtually every attribute, our Oregon operations have resulted in "very satisfied" scores in the 94-97% range. For example, the overall customer satisfaction level for the second quarter of 2007 was 97% "very satisfied."

Q. Please briefly describe Avista's subsidiary businesses.

A. Avista Corp.'s primary subsidiary is our information and technology business, Advantage IQ, described below, which is headquartered in Spokane, Washington. In June 2007, Avista Energy, Inc., a subsidiary of Avista Corp., sold substantially all of its contracts and ongoing operations to Coral Energy Holding, L.P. In 2001, Avista disposed of substantially all of the assets of Avista Communications, and sold the majority of Avista Labs in 2003. Avista currently retains a 6.8% share in Avista Labs successor company, ReliOn, held under Avista Capital, as reflected in the diagram of Avista's corporate structure provided on page 2 of Exhibit No. 101.

Q. Would you further elaborate on your description of Avista Energy?

A. Yes. Avista Energy, which commenced operations in 1997, was an electricity and natural gas marketing, trading and resource management business, operating primarily within the Western Electricity Coordinating Council (WECC) geographical area. Avista Energy focused on, among other things, the optimization of combustion turbines and hydroelectric assets owned by other entities, long-term electric supply contracts, natural gas storage, and electric transmission and natural gas transportation arrangements.

Q. Please describe the Company's decision to divest itself of Avista Energy.

A. In April 2007, the Company announced that Avista Energy had signed a definitive agreement to sell substantially all of its contracts and ongoing operations to Coral Energy Holding, L.P. and certain of its subsidiaries (Coral Energy), a subsidiary of Shell. The transaction closed June 30, 2007. The agreement also included the sale of the operating assets of Avista Energy Canada, Ltd, which was acquired by Coral Energy Canada Inc., a subsidiary of Coral Energy.

Over its ten years in operation, Avista Energy has provided benefits to Avista and its shareholders, and in particular, it provided critical financial support to Avista during the energy crisis of 2000 and 2001, and its aftermath. It became clear to the Company, however, that Avista Energy would be more successful if owned by a larger company with the financial resources to support its activities in today's marketplace. While this sale resulted in a near-term reduction in earnings, it will reduce the earnings volatility of Avista Corp., and reduce our risk profile, both of which, we believe, will be viewed positively by the rating agencies over the longer term.

Q. How does the Company plan to use the proceeds from this sale?

A. The sale of Avista Energy was an all-cash transaction reflecting the book value of the Company, along with adjustments in accordance with the purchase and sale agreement. Initially, the Company has paid down debt and entered into short-term investments with the proceeds. Over time, the majority of proceeds are expected to be reinvested in utility assets.

Q. Please provide an overview of Advantage IQ.

A. Advantage IQ, formerly known as Avista Advantage, commenced operations in 1998 and is a provider of utility bill processing, payment and information services to multi-site customers. Advantage IQ analyzes and presents consolidated bills on-line to clients, and pays utility and other facility-related expenses for multi-site customers throughout North America, such as the Federal Aviation Administration, Alaska Airlines, Frito Lay, Hard Rock Café, and Starbucks, to name a few. Information gathered from invoices, providers and other customer-specific data allows Advantage IQ to provide its customers with in-depth analytical support, real-time reporting and consulting services with regard to facility-related energy, waste, repair and maintenance, and telecom expenses.

Q. What is the status of the Holding Company formation?

A. In February 2006, Avista filed for regulatory approval of the proposed formation of a holding company (reorganization) with the Federal Energy Regulatory Commission (FERC) and the public utility commissions in Washington, Idaho, Oregon and Montana, conditioned on approval by Shareholders. On April 18, 2006 FERC issued its "Order Authorizing Disposition of Jurisdictional Facilities" in Docket No. EC06-85-000 approving the Company's reorganization. Shareholder approval of the reorganization was granted at Avista Corp.'s Annual Shareholder meeting May 11, 2006. On June 30, 2006, the Idaho Public Utilities Commission issued an order approving Avista's reorganization application, based on a settlement in that state. On February 28, 2007, the Washington Utilities and Transportation Commission issued an order approving Avista's reorganization application, based on a settlement in that state. The Montana Commission has yet to act on Avista's Reorganization application, and the procedural schedule for consideration of the Company's application in Oregon has been suspended, by agreement of the parties.

III. HISTORY

Q. What is Avista Utilities' rate history in Oregon?

A. In 1991, the Company, then known as The Washington Water Power Company, doing business as WP Natural Gas (WPNG), acquired the Oregon and California natural gas service territory of CP National. WPNG implemented a 0.50% decrease in base rates at that time and instituted a four and one-half year rate freeze. Upon the end of this rate stability period, a 2.94% general rate decrease was implemented effective December 1, 1995. Thereafter, the Company again implemented a base rate decrease of 2.1% effective December 1, 1997. In October 2003, the Company implemented a 9.9% increase in base rates. When combined with the proposed overall general increase of 2.3%, base rates will have only increased 6.66% since we acquired the properties sixteen years ago.

Q. Has the Company considered the possible economic impacts of the Company's rate proposals in its service territory?

A. Yes. Through my involvement with area chambers and economic development agencies, I am particularly mindful of the impact rate increases have on our customers. This includes businesses within our service area and the important role the utility plays in the communities we serve. Avista will continue to aggressively manage costs to achieve the appropriate balance in providing safe and reliable service at competitive rates, while rebuilding a financially healthy utility. In the long term, a financially healthy utility will foster customer satisfaction and enable the utility to finance under reasonable terms the new infrastructure required over time to serve our customers.

Q. The proposed rate increase is related to changes in the costs of providing natural gas service to customers. Is the Company proposing any changes to natural gas commodity costs in this case?

A. No. Avista is not proposing changes in this filing to the natural gas commodity costs included in customers' current rates. Changes in commodity costs are addressed in the annual purchased gas adjustment (PGA) filings.

The natural gas industry has experienced significant pricing volatility and upward price pressure on the wholesale cost of natural gas. Natural gas prices in the Pacific Northwest are increasingly affected by supply and demand factors in other regions of the United States and Canada because of growth in transcontinental pipeline capacity. Global energy markets, including oil prices, are also affecting natural gas prices.

Q. Does the Company have programs in place to mitigate the impacts on customers of the proposed rate increase.

A. Yes. Avista Utilities offers a number of programs for its Oregon customers, such as energy efficiency programs, the Low Income Rate Assistance Program (LIRAP), Project Share for emergency assistance to customers, a Customer Assistance Referral and Evaluation Service (CARES) program, senior energy outreach, level pay plans, and payment arrangements. Some of these programs will serve to mitigate the impact on customers of the proposed rate increase. Additional detail concerning these programs is provided later in my testimony.

IV. CURRENT AND FUTURE ISSUES

Q. Please describe the Company's Advanced Meter Reading Program (AMR).

A. The Oregon AMR project was completed in December 2004. Total expenditures for the project were $2.6 million and are included in this filing. Without the use of AMR technology, the O&M meter reading costs in Oregon were projected to be approximately $491,000 in fiscal year 2006. Actual costs in Oregon for fiscal year 2006 were approximately $179,000. Thus, the investment in advanced meters provided the opportunity to substantially reduce the annual expense related to meter reading.

The AMR project involved the installation of Encoder, Receiver, and Transmitter (ERT) devices on existing natural gas meters, regrouping customers in the Customer Information System (CIS), and transitioning to mobile data collection. With AMR, when a company vehicle equipped with a collector drives through an area, a radio signal is sent out to signal the ERTs in the area to begin transmitting current meter data. An AMR technician with a mobile collector can read up to 5,000 meters per day, a significant increase over the 300 to 500 meters an individual walking a meter route could complete. The AMR technology provides Avista with the ability to add additional meters and read them efficiently with existing personnel.

Prior to implementation of AMR, Avista employed a total of 9.4 FTE meter readers in Oregon. The Company now employs 1.7 FTE AMR technicians in Oregon.

Q. Please describe the Company's Mobile Dispatch Operation.

A. In June 2006, the implementation of wireless laptop computers with mobile maps (Mobile Dispatch) was deployed to all Avista gas servicemen. Mobile Dispatch automatically dispatches work orders to Avista servicemen throughout the day through wireless technology to laptop computers mounted in Avista service trucks. Prior to Mobile Dispatch, orders were created in Avista's work management system and printed at the local construction offices. Employees in each office would sort, assign and dispatch (via phone, pager, fax or in person) orders each morning. The field employees would work with the orders and call in the completed work periodically throughout the day or simply turn-in the stack of completed orders at the end of the day. The completed orders were manually completed by back-office employees who entered the information regarding the order back into the work management system.

The paper processes made it nearly impossible to track the status of individual orders and fieldworkers throughout each day. It was also very difficult for the Dispatchers to keep up with the volume of paper being sent out each morning, changes to the orders that occurred during the day, and completed orders returned at the end of the shift.

Mobile Dispatch has automated the order creation, modification and completion process. With the new technology, orders are created in the work management system and are automatically dispatched to the correct field worker based on the order's Latitude/Longitude position and the person assigned to work orders in that area. Once a field employee has been identified, the order is sent through wireless technology to the laptop computer mounted in Avista's service truck. The order is then reviewed by the employee for specific information needed to complete the work. The order status is transmitted back to the dispatch center, as the employee indicates they are en route, on-site, and/or have completed the work. The completed order is transmitted wireless back to the work management system where it is closed automatically.

Q. What benefits does Mobile Dispatch provide?

A. Successful implementation of streamlined work processes and supporting technology for the business processes described above will allow Avista to achieve a number of financial and customer service benefits including:

- Increased field productivity via efficient order routing and elimination of paper processes;

- Improved dispatcher productivity with efficient order assignment, dispatching, monitoring and closing processes;
- Enhanced customer service with improved appointment booking capability and reliability;
- Reduced costs required to perform an equal amount of work – labor and vehicle costs; and
- Improved safety in the field with alerts and follow-up on workers.

The reduction in operating costs are used to offset all or a portion of the investment in technology to achieve these efficiencies and service enhancements.

V. 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 energy efficiency programs, the Low Income Rate Assistance Program (LIRAP), Project Share for emergency assistance to customers, a Customer Assistance Referral and Evaluation Service (CARES) program, level pay plans, and payment arrangements. Some of these programs will serve to mitigate the impact on customers of the proposed rate increase.

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.

In September 2006, Avista launched several new market transformation programs in partnership with the Energy Trust of Oregon (ETO). These programs include ENERGY STAR® new construction, ENERGY STAR® manufactured homes and energy efficient washing machines. The ETO's goal is to transform 20% of the new construction market over a five year period. The Company's 2007 draft Natural Gas Integrated Resource Plan identified a 2008 goal of 350,000 first-year therms.

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

A. The low-income rate assistance program (LIRAP), collects approximately $230,000 (or .438 cents per therm annually) from a 0.50% distribution charge on natural gas service. These funds are distributed by community action agencies in a manner similar to the Federal and State-sponsored Low Income Heating Energy Assistance Program (LIHEAP). Avista Utilities' LIRAP program supplements the reach of available LIHEAP funds. The Company, with the assistance of community action agencies and the Commission, directed this program toward those members of the community least able to pay for natural gas service.

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 region. 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. Avista Utilities has consistently had relatively high per-customer contributions when compared to other utilities with Project Share programs. Avista Utilities' customers donated $351,327 on a system basis in 2006, of which $48,286 was directed to Oregon Community Action Agencies. In addition, the Company contributed

$40,000 to Oregon customers in 2006.

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. Over 6,590 (or 7%) of Oregon natural gas customers are on Comfort Level Billing.

In addition, the Company's Contact Center Representatives work with customers to set up payment arrangements to pay energy bills. In 2006, 23,348 Oregon customers were provided with over 48,156 such payment arrangements.

Q. Please summarize Avista's CARES program.

A. In Oregon, Avista is currently working with over 385 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 2005/2006 heating season, 2,857 Oregon customers received $641,607 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.

Q. Are there other noteworthy items that you would like to address?

A. Yes. There are several items of which I am particularly proud. The Company's contact center has been recognized nationally for its quality and efficiency. The Medford call center is networked with call centers in Lewiston, Idaho, Coeur d'Alene, Idaho, and Spokane, Washington. In 2006, this allowed a total of 50 full-time equivalent call center employees to effectively respond to over 830,000 calls from natural gas and electric customers in our three state service territory.

I am also very pleased with the previously discussed LIRAP and energy efficiency programs. I appreciate the community action agencies' collaboration and the Commission's approval to effectuate the LIRAP program.

VI. 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. Malyn Malquist, Executive Vice President and Chief Financial Officer, will address the Company's capital structure, the proposed cost of embedded debt and preferred stock 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. William E. Avera, as a principal in 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 an 11.0% return on equity.

Mr. Kevin Christie, Director of Gas Supply, will discuss the pro formed capital additions included in this filing. In addition, he will also discuss the Jackson Prairie Expansion Project.

Ms. Elizabeth Andrews, Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposals. In addition, her testimony and exhibits will cover accounting and financial data in support of the Company's need for the proposed increase in rates and allocation methodologies. She will also explain pro formed operating results, including expense and rate base adjustments made to actual operating results and rate base.

Ms. Tara Knox, Senior Regulatory Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Ms. Knox discusses her study results and how each schedule's present and proposed rates compare to the indicated cost. Ms. Knox also discusses the weather normalization adjustment methodology.

Mr. Brian Hirschkorn, Manager, Retail Pricing, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. In addition, he will also address the Company's revenue normalization adjustment.

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

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

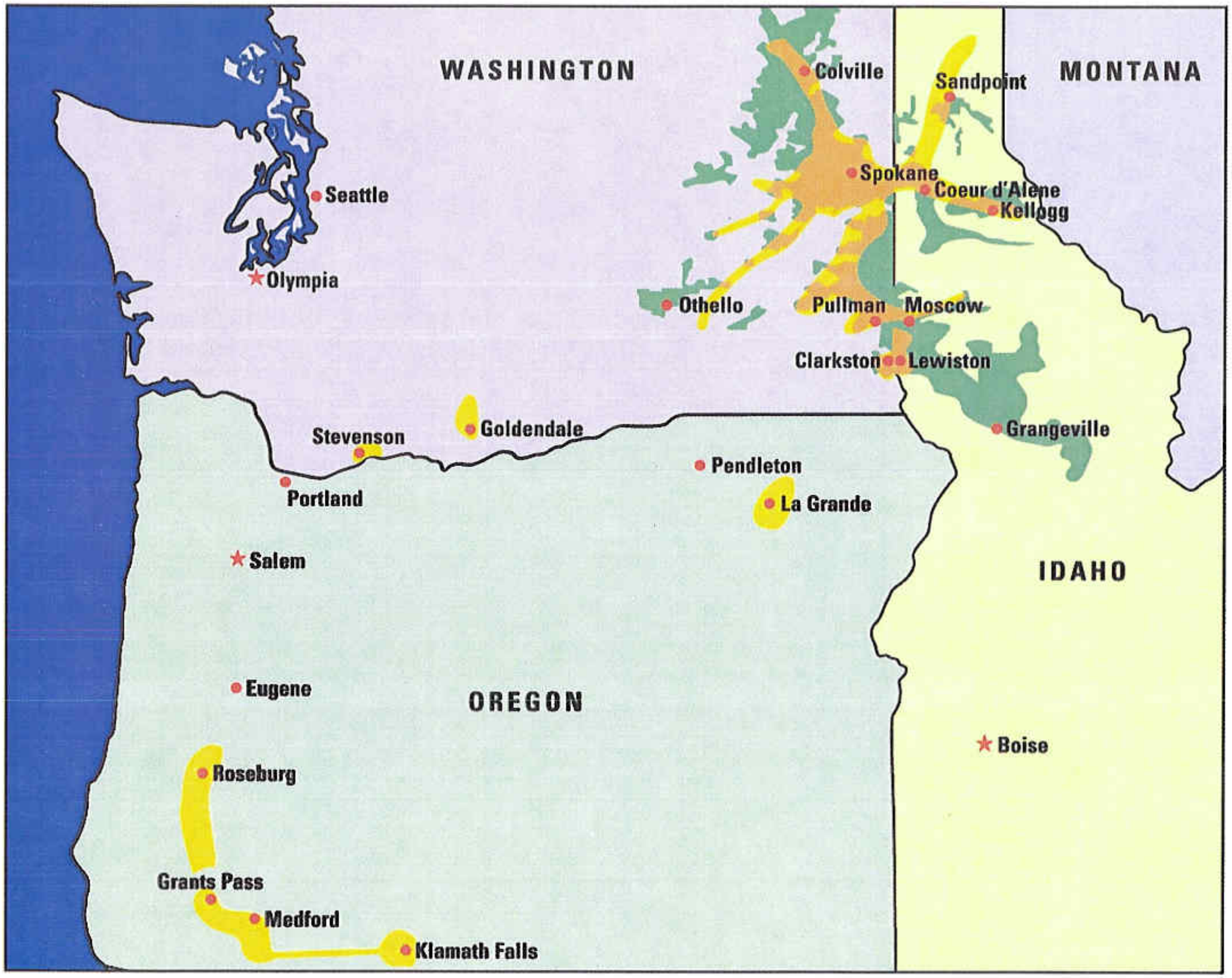
AVISTA CORP

SCOTT L. MORRIS
Exhibit No. 101

Policy and Operations

MAP

Avista's electric and natural gas service areas



Legend

- Electric Service Areas
- Natural Gas Service Areas
- Electric and Natural Gas Service Areas

Avista Utilities Service Territory

Data as of December 31, 2004

Retail Electric Customers by State
Washington *220,000*
Idaho *113,000*

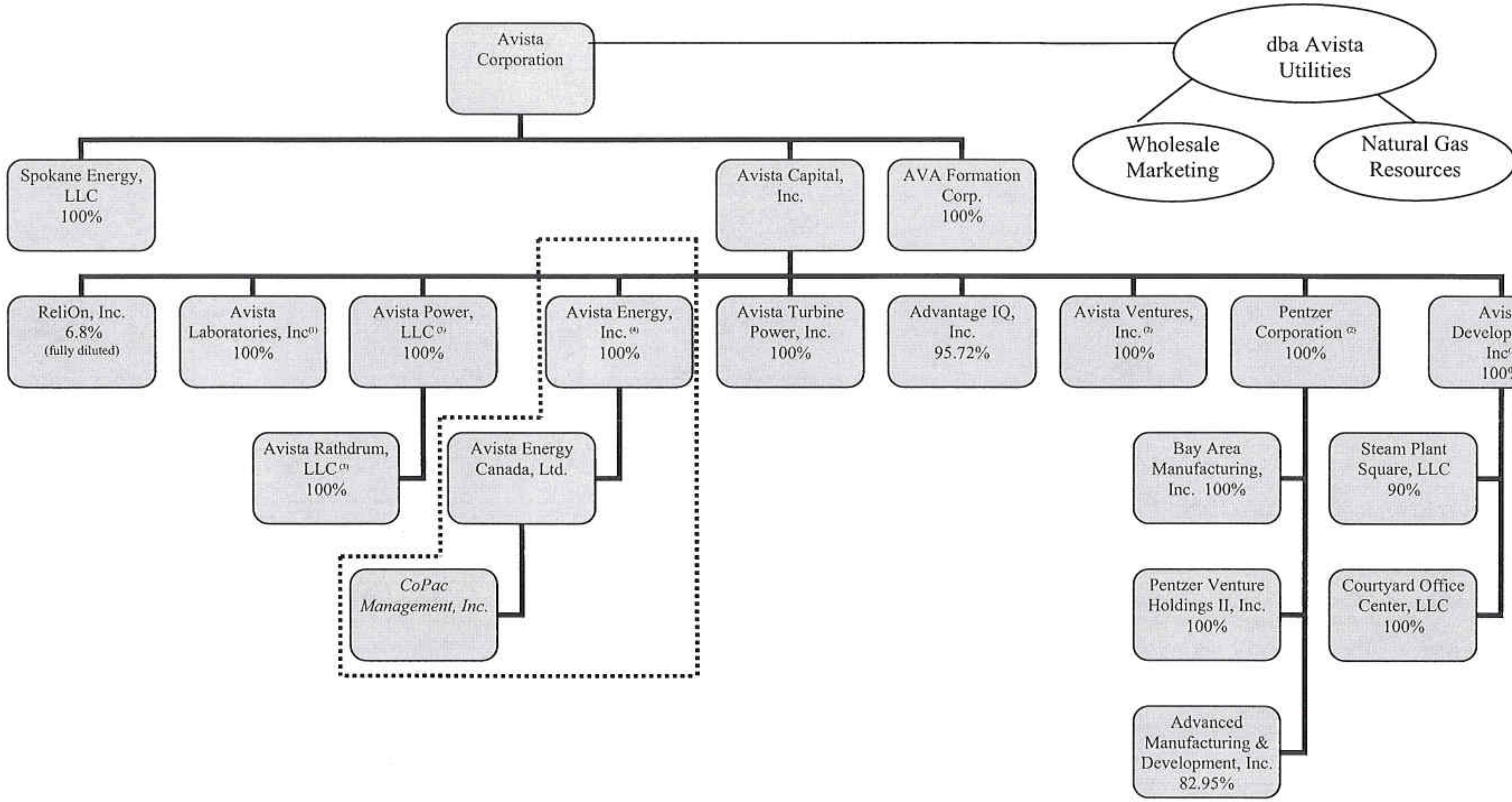
Total Retail Electric Customers **333,000**

Retail Natural Gas Customers by State
Washington *135,000*
Idaho *66,000*
Oregon *90,000*

Total Retail Natural Gas Customers **281,000**

Avista Corporation and Affiliates

August 10, 2007



Denotes Energy Affiliates

(1) Inactive – See note a) below
(2) No Employees, passive income
(3) Ceased active development of additional projects
Note a) Other Inactive Subsidiaries under Avista Capital, not shown above, include: Avista Communications, Inc.; and Coyote Springs 2, LLC
Note b) Additional Subsidiaries under Avista Corp., not shown above, for the special purpose financing include: Avista Receivables Corp.
(4) These Company assets were sold in June 2007

Updated 08/10/07

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF MALYN K. MALQUIST
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 Malyn K. Malquist. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed by Avista Corporation as Executive Vice President and Chief Financial Officer.

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

A. Yes, I received a Bachelors degree and a Master of Business Administration degree from Brigham Young University. I have also attended a variety of utility finance courses and leadership programs during my 25+ year utility career.

I joined Avista in September of 2002 as Senior Vice President. In November 2002 I was named to the additional position of Chief Financial Officer. I was named Executive Vice President in May 2006. Prior to joining Avista, I was General Manager of Truckee Meadows Water Authority in Reno, Nevada, which was separated out from Sierra Pacific Power Company in 2001. I was Chief Executive Officer of Data Engines, Inc., a high tech company located in Reno from June to October of 2000. From April 1994 to April 2000, I was employed by Sierra Pacific Resources, first as the company's Chief Financial Officer and later as its Chairman of the Board and Chief Executive Officer. Following the merger of Sierra Pacific Resources with Nevada Power Company in 1999, I became the President of both Sierra Pacific Power Company and Nevada Power Company. For the sixteen-year period prior to 1994, I was employed by San Diego Gas & Electric Company in various positions, including Treasurer and Vice President – Finance.

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

A. I will provide a financial overview of the Company and will explain the overall rate of return proposed by the Company in this filing for its natural gas operation. The proposed rate of return is derived from Avista Utilities' costs of debt (including long-term debt and long-term debt to affiliated trusts), and common equity, weighted in proportion to the proposed capital structure.

I will address the proposed capital structure and debt cost components. Company witness Dr. Avera will testify to the appropriate return on equity for the Company.

In brief, I will provide information that shows:

- We have been aggressively rebuilding our financial health by improving our cash flow, managing our costs, paying down debt and financing debt maturities and repurchases with lower cost debt.

- We have been strategically reducing our involvement in our unregulated subsidiaries, as evidenced by the sale of Avista Energy in June 2007.

- In addition, capital expenditures of approximately $416 million are planned for 2007-2008 for maintenance and replacement of our natural gas utility systems, customer growth, and investment in generation, transmission and distribution facilities for the electric utility business. Avista needs adequate cash flow from operations to fund these requirements.

- Avista's corporate credit rating from Standard & Poor's is currently BB+, which is below investment grade. Avista Utilities should operate at a level that will support a strong investment grade corporate credit rating, meaning at least a "BBB+". The Company's financial performance has improved since 2001, however, we have not improved financial ratios to a level that would regain an investment grade corporate credit rating.

- The Company has proposed an overall rate of return of 8.98%, including a 51.15% equity ratio and an 11.0% return on equity. In this case, although we believe an ROE greater than 11.0% is supported and is warranted, as testified by Mr. Avera, we also believe the 11.0% provides a reasonable balance of the competing objectives of providing an appropriate return on shareholders' capital, regaining financial health within a reasonable period of time, and the impacts that increased rates have on our customers.

An improved credit rating to investment grade is only likely if the Company's financial strength and its outlook improve for a sustained period of time. The Company's initiatives to carefully manage its operating costs and capital expenditures are an important part of improving performance, but are not sufficient without revenues from the general rate request for our natural gas business in this case. Certainty of cash flows from operations can only be achieved with the continued support of regulators in allowing the timely recovery of costs and the ability to earn a fair return on investment.

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

A. Yes. I am sponsoring Exhibit No. 201, which was prepared under my direction. Avista's credit ratings by the three principal rating agencies are summarized on page 1, and Avista's actual capital structure at December 31, 2006 and pro forma capital structure at June 30, 2008 are included on page 2.

II. FINANCIAL OVERVIEW

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

A. Although the Company has made good progress in improving its financial health in recent years, Avista's corporate credit ratings remain below investment grade. During the energy crisis of 2000 and 2001, it was necessary for the Company to issue a significant amount of debt to cover natural gas and electric costs incurred but not yet paid for by Avista's customers. These costs were deferred for future recovery under accounting treatment approved by the respective Commissions.

During that time investors and lenders were reluctant to invest in the utility industry, including Avista, and were demanding higher interest rates. Much of the debt issued by Avista during this time was at rates exceeding 9%. As a result, Avista's annual interest costs rose from approximately $69 million in 2000 to over $105 million in 2001 and 2002. In addition, Avista's debt ratio (including long-term debt to affiliated trusts) rose from 57.6% at December 31, 2000 to 64.2% at December 31, 2001. The amount of debt outstanding (including long-term debt to affiliated trusts) rose from $1,032 million at December 31, 2000 to $1,353 million at December 31, 2001. By prudently managing our costs and cash flow, we have improved our debt ratio to 53.0% as of June 30, 2007. Total debt (including long-term debt to affiliated trusts) has also decreased to $1,077 million as of June 30, 2007.

Q. What actions have the Company taken to improve its financial health?

A. We have been aggressively rebuilding our financial health by improving our cash flow, managing our costs, and improving our debt structure.

The rating agencies have recognized the improvement in the Company's financial health as evidenced by the following rating agency actions: a) In July 2007, S&P affirmed its corporate credit rating of BB+ with a positive outlook for Avista. The S&P rating has been maintained since December 2002 and the outlook was changed from stable to positive in April 2007; b) In September 2007, S&P raised Avista's first mortgage bond rating to BBB+ from BBB- as a result of S&P modifying the criteria related to assigning first mortgage bond ratings; c) In June 2007, Moody's placed the Company's ratings on review for potential upgrade. The Moody's rating of Ba1 and outlook of stable has been maintained since March

2004; d) In August 2007, Fitch ratings upgraded the senior secured, senior unsecured and long-term issuer default ratings for Avista to BBB, BBB- and BB+, respectively.

On June 30, 2007, Avista Energy (an indirect subsidiary of Avista Corp.) completed the sale of substantially all of its contracts and ongoing operations. Over time, Avista Corp. plans to redeploy the majority of the proceeds from the transaction into its regulated utility operations by reducing debt and investing in capital assets. Rating agencies have viewed this as a positive credit development. However, rating agencies have indicated that continued regulatory support as well as sustained improvement in financial metrics will be critical to improving the Company's credit ratings.

Although we are making progress in improving the Company's financial condition, we are still not as strong as we need to be, which is why the rating agencies are not yet ready to upgrade our credit rating to investment grade. Typically, the rating agencies would first place us on "Positive Outlook" about one year prior to an actual upgrade. Furthermore, there is additional review required by the rating agencies when a company's upgrade involves a "cross-over" (i.e. a change from non-investment grade to investment grade rating).

Q. What additional steps is the Company taking to improve its financial health?

A. The Company is continuing to rebuild its financial condition in three areas. First, we are working to assure we have adequate funds for operations, capital expenditures and debt maturities, through lines of credit with our banks and maintaining adequate access to the capital markets. We have worked with our banks to insure that we have adequate liquidity through the availability of our credit facility on the most economic basis possible.

Additionally, the Company has recently obtained a portion of its capital requirements through equity issuance. The Company issued 3.2 million shares of common stock in December 2006. We also maintain an ongoing dialogue with the rating agencies regarding the measures being taken by the Company to regain an investment grade corporate credit rating.

Second, the Company is exercising a high level of scrutiny with regard to expenses and capital investment in the operation of the business, without compromising safety and reliability.

Finally, the Company is working through regulatory processes to recover our costs in a timely manner so that earned returns are closer to those allowed by regulators in each of the states we serve. This is one of the key determinants from the rating agencies' standpoint when they are reviewing our overall credit rating.

III. CREDIT RATINGS AND PLAN TO RETURN TO INVESTMENT GRADE

Q. Please explain the ratings for Avista's debt and other securities, and the implications of these ratings in terms of the Company's ability to access financial markets.

A. Avista's credit ratings by the three principal rating agencies are summarized on page 1 of Exhibit No. 201. 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 that they would have in the event that the organization experiences severe financial stress. Investment risks include the likelihood that a company will not meet all of its debt obligations in terms of timeliness and amounts owed for principal and interest. Secured debt receives the highest ratings and priority for repayment and, hence, has the lowest relative risk. Typically, a higher credit rating will result in an overall lower interest cost.

Q. What are the risks facing Avista and the rest of the utility sector which have an impact on the Company's credit ratings?

A. Among the risk factors are the recoverability of natural gas and power costs, level and volatility of wholesale electric market prices and natural gas prices for fuel costs, liquidity in the wholesale market (fewer counterparties and tighter credit restrictions), streamflow and weather conditions, changes in legislative and governmental regulations, security concerns related to terrorism, ability to relicense hydro projects and availability of funding.

Additional risks impacting the utility sector include higher capital expenditures for environmental compliance, increased competition for financial capital, and full and timely recovery of prudently incurred costs.

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

A. Avista Utilities should operate at a level that will support a strong investment grade corporate credit rating, meaning at least BBB+, using S&P's rating scale. Prior to 2001, Avista's credit rating was in the A-/BBB+ range. Ratios required to support this level of credit rating are included in Table 1 below. This Commission has historically recognized that financially healthy utilities have lower financing costs which, in turn, benefits customers. In addition, financially healthy utilities are better able to invest in the needed infrastructure over time to serve their customers, and to withstand the challenges and risks facing the industry.

Q. Why is it important to be investment grade?

A. A utility is a capital-intensive business and, as such, needs to have ready access to capital markets under reasonable terms. Access is more difficult and more expensive for non-investment grade companies. In many instances, investors are precluded by law, regulation, or policy from investing in non-investment grade securities. As new financing is required in the future to finance new customer additions, utility plant additions, and debt maturities, the cost of new and replacement debt will be higher for a non-investment grade issuer.

Non-investment grade companies are also subject to more restrictive credit requirements from vendors and other counterparties. In fact, the Company's ability to purchase natural gas and power has been impacted by its below-investment grade rating, and there are fewer counterparties willing to do business with us. The lower credit rating also requires the Company to post more collateral with counterparties than would otherwise be required with a higher credit rating. This results in increased costs. It also reduces financial flexibility as a certain amount of capacity under our credit line is reserved for letters of credit.

Q. What are the credit rating ratios used by the rating agencies?

The Standard & Poor's (S&P's) financial ratio benchmarks used to rate companies such as Avista are set forth below:

Standard & Poor's Financial Ratio Benchmarks* Table 1					Avista Corp (BB+) **	
Ratio	AA	A	BBB	BB	Unadjusted	Adjusted
Fund from operations/interest coverage (x)	4.5 - 5.5 (x)	3.8 - 4.5(x)	2.8 - 3.8(x)	1.8 - 2.8(x)	3.4 (x)	2.5 (x)
Funds from operations/total debt (%)	30 - 40%	22 - 30%	15 - 22%	10 - 15%	19.2%	13.0%
Total debt/total capital (%)	35 - 42%	42 - 50%	50 - 60%	60 - 65%	53.7%	57.6%

BBB = investment grade credit rating

* *Ranges for companies with a Business Profile of "5", which includes Avista Corp. Includes adjustments made by S&P*

*** As of 12/31/06*

Q. Please describe how these ratios are calculated and what they mean?

A. The first ratio, "Funds from operations/interest coverage (x)", calculates the amount of cash from operations that is available to cover interest requirements. The second ratio, "Funds from operations/total debt (%)", calculates the amount of cash from operations as a percent of total debt, and the third ratio, "Total debt/total capital (%)", is the amount of debt in our total capital structure. S&P looks at many other financial ratios, however, these are the three primary ratios they use when analyzing our financial profile.

Q. Do rating agencies make adjustments to the financial ratios that are calculated directly from the financial statements of the Company?

A. Yes. Rating agencies make adjustments to debt to factor in off-balance sheet commitments (for example, the accounts receivable program, purchased power agreements, operating leases and the unfunded status of pension and other post-retirement benefits) that negatively impact the ratios. The adjusted financial ratios for Avista are included in Table 1 above.

Q. What must Avista do to move each ratio within the required range to meet investment grade coverage ratios?

A. In order to move each adjusted ratio within the required range to meet investment grade requirements, Avista must reduce its total debt balances and increase its available funds from operations. Although the Company has continued to work towards paying down its total debt, the negative impacts to cash flow caused by below-normal hydroelectric generation and volatility of wholesale electric market prices and natural gas prices in recent years has adversely affected Avista's ability to reduce total debt. Deferral balances are also an area that concerns the rating agencies.

Q. Do the rating agencies look at any other factors when evaluating a company's credit quality?

A. Yes, they do. The rating agencies evaluate the regulatory environment including the timely recovery and certainty of recovery of costs, the competitive environment in which we operate, the company's resource picture, quality of management and financial policy. Therefore, while the ratios are utilized in their quantitative evaluation of a company, they are not the only factors that are taken into account. Additionally, the rating agencies review and take into account the Company's forecast when determining the Company's credit quality.

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

A. According to my discussions with the rating agencies, the regulatory environment in which a company operates is a major factor in determining a company's creditworthiness. In a recent article published by S&P entitled "Top Ten Credit Issues Facing U.S. Utilities", S&P stated that "the regulatory and political dynamic will remain the most important determinant of credit quality."[1]

Although Avista has a natural gas tracking mechanism (PGA) to provide recovery of the majority of the variability in commodity costs, these changes in costs must be financed until the costs are recovered from customers. The deferral balance for natural gas in Oregon was $9.4 million as of August 31, 2007. As noted above, investors and rating agencies are concerned about regulatory lag and cost-recovery and the negative cash flow and liquidity issues that result from such lag.

IV. CASH FLOW

Q. What are the Company's near-term capital requirements?

A. As a combination electric and natural gas utility, over the next few years capital will be required for customer growth, necessary maintenance and replacements of our natural gas systems, and investment in generation, transmission and distribution facilities for the electric utility business. The amount of capital expenditures planned for 2007-2008 is approximately $416 million.

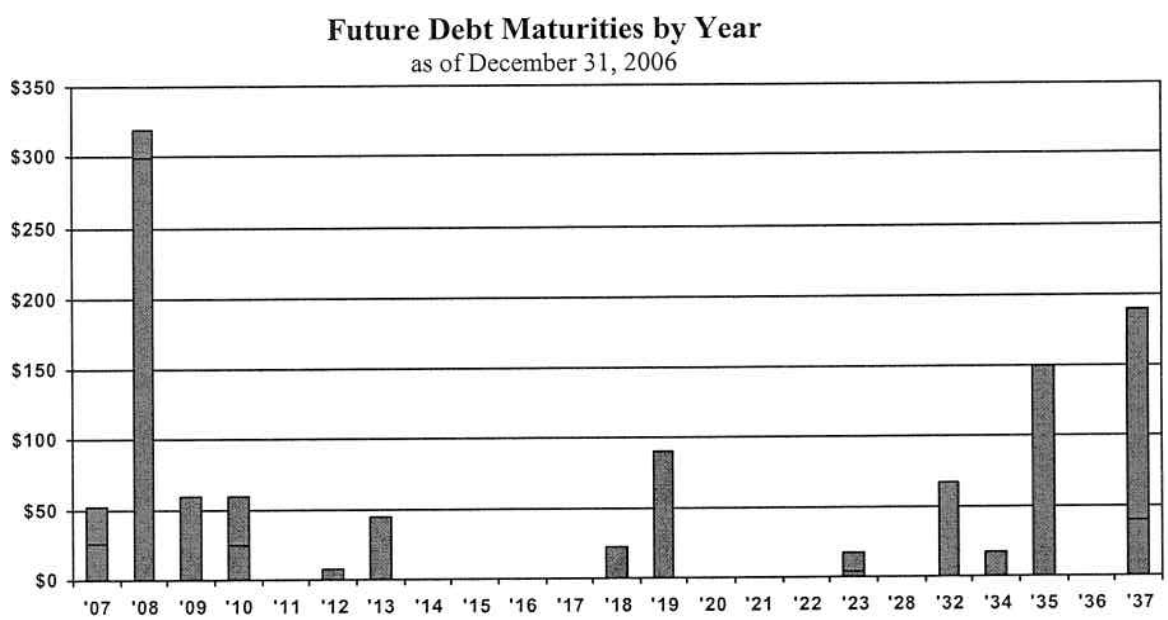
Major capital expenditures are a normal part of utility operations. Customers are added to the service area, roads are relocated and require existing facilities to be moved, and facilities continue to wear out and need replacement. These and other requirements create the need for significant capital expenditures each year. In addition, we are seeing significant

[1] Standard & Poor's, *Top Ten Credit Issues Facing U.S. Utilities* (January 29, 2007).

increases in the costs of materials. Access to capital at reasonable rates is dependent upon the Company maintaining a strong capital structure, sufficient interest coverages, and investment grade credit ratings.

Q. What are the Company's near-term plans related to its debt?

A. In December 2006, the Company issued $150 million of debt. The $150 million of new debt issuance is due in 2037 and replaced debt that was due January 1, 2007. The December 2006 refinancing has been reflected in the chart below and in our proposed cost of debt. After considering the December 2006 refinancing, the Company has approximately 34% of its total debt maturing in 2007 and 2008, with the majority maturing in 2008. A stronger credit rating would likely allow the Company to refinance the 2008 debt maturities at lower interest rates. Therefore, it is important for the Company to improve its financial condition and increase its credit ratings quickly, which will result in lower financing costs for customers in the future.



Q. Has the Company taken any steps to address the significant debt maturities it faces in 2008?

A. Yes it has. As a result of the historically low interest rate environment that existed in 2004, the Company entered into two forward-starting interest rate swaps totaling $125 million or almost 45% of the 2008 debt maturities. The swaps have contract terms of ten years beginning in 2008. These agreements secured a fixed rate for a significant portion of the total future interest rate. These agreements do not lock in Avista's credit spread; therefore, the Company could realize lower financing costs as a result of improved credit ratings.

Q. What other financing activities did the Company complete that will lower its interest costs?

A. The Company refinanced $60 million of 7.875% Trust Preferred Stock in April 2004 at a rate of 6.50% through April 2009. In addition, the Company issued the following First Mortgage Bonds:

a) November 2004 - $90 million at 5.45% with a 15-year maturity
b) November 2005 - $150 million at 6.25% with a 30-year maturity and
c) December 2006 - $150 million at 5.70% with a 30.5-year maturity.

Cost of total debt has decreased from 8.44% at December 31, 2003 to 7.74% at December 31, 2006. The Company also issued 3.2 million shares of common stock in December 2006.

Q. What is the status of the Company's line of credit secured by first mortgage bonds?

A. The facility has been sized to allow the Company to fund at least one year of capital expenditures, plus required working capital and counterparty collateral requirements to assure flexibility given both the volatile financial markets and volatile energy commodity prices.

Many purchases of natural gas, or contracts for pipeline capacity to provide natural gas transportation, have required collateral, and/or prepayments, given the Company's credit rating. The line of credit is our primary source of immediate cash for borrowing to meet these needs and for supporting the use of letters of credit. These cash needs are also met through the Company's receivables purchase agreement. A line of credit is required to manage daily cash flow since the timing of cash receipts versus cash disbursements is never totally balanced.

Prior to December 2004, the line of credit had a term of 364 days. In December 2004, we were able to extend the maturity to five years and lower our financing costs. In April 2006, the Company amended its corporate line of credit, lowering the borrowing costs, extending the term again to five years and lowering the total line to $320 million (from $350 million). The Company has the option of increasing the line by $100 million (up to $420 million) at any time during the term of the agreement. The agreement includes the option to release the first mortgage bond security if the Company regains its investment grade credit rating. This demonstrates recognition by our banks that Avista's financial condition is improving.

Q. What are Avista's plans regarding common equity and why is this important?

A. Avista has improved the common equity ratio of its consolidated capital structure from 34.2% at December 31, 2001 to 45.7% as of June 30, 2007. This has been accomplished by improving our cash flow, managing our costs, and paying down debt. As mentioned earlier, the company partially accomplished this through the issuance of 3.2 million shares in December 2006.

The sale of Avista Energy and the redeployment of the majority of those funds in the utility business improved the utility equity layer. It is important to the rating agencies who rate the Company's securities, and hence an important component of the Company's cost of doing business, for Avista to have a more balanced debt/equity ratio in order to minimize the risk of default on required debt interest payments.

Avista will issue common equity in the future when it is appropriate to finance the capital requirements of the Company. However, Avista does not have any plans to issue a significant amount of additional common equity at this time.

Q. What are Avista's plans regarding preferred equity?

A. Avista had $26.25 million of preferred equity outstanding as of December 31, 2006. The entire amount of the preferred equity matured in September 2007. Currently, Avista does not have plans to issue additional preferred equity. Avista will continue to evaluate the appropriateness of preferred equity within its overall capital structure.

V. CAPITAL STRUCTURE

Q. Please explain the capital structure proposed by Avista in this case.

A. Avista's current capital structure consists of a blend of long-term debt, long-term debt to affiliated trusts and common equity necessary to support the assets and operating capital of the Company. Short-term debt carried on the Company's line of credit has been excluded from the capital structure. The proportionate shares of Avista Corp.'s actual capital structure on December 31, 2006, are shown on page 2 of Exhibit No. 201. A pro forma capital structure is also shown in the Exhibit, which reflects expected changes for the period ending June 30, 2008. Supporting workpapers provide additional details related to these adjustments.

The rate of return to be applied to rate base in this proceeding is equal to the weighted average cost of capital, taking into account the pro forma adjusting items. As shown on page 2 of Exhibit No. 501, Avista Utilities is proposing an overall rate of return of 8.98%.

Q. How does Avista conduct its financing as a multi-jurisdictional and multi-service utility?

A. Avista provides natural gas distribution service in Oregon, Washington, and Idaho. Avista generates, transmits and distributes electricity in Washington and Idaho. Funding for these jurisdictions is provided through a central treasury function. A central treasury function is utilized as it is more efficient and cost-effective to pool our resources across jurisdictions.

The cost of funds for each jurisdiction is the same. Likewise, we provide shared services across all jurisdictions that result in a benefit of scale to each of the jurisdictions. The benefits of being a multi-service utility, that operates in a geographic region spanning parts of three states, results in customers sharing in the costs of service, cost of capital, and the level of service provided. Reasonable allocations can be made to determine the fair sharing of costs among jurisdictions, however, all jurisdictions use the same pool of resources for these items and it is not possible to specifically assign many of the dollars for shared resources directly to specific jurisdictions.

The capital requirements for the entire utility are managed as a whole. Capital for customer demands is driven by the needs of customers in each respective jurisdiction and is provided from a shared funding pool. Any distinctions between the cost of capital among our jurisdictions would be difficult to determine and unsupportable by the facts of how capital is obtained and used for the entirety of utility operations.

The selection of debt financing comes from a combination of financial market dynamics, funding needs, financial flexibility and judgment. We continuously review our existing debt obligations and review what may be available in the financial markets. Our goal is to provide the lowest cost debt structure possible while preserving long-term and short-term flexibility and access to needed funds.

VI. COST OF DEBT

Q. How have you determined the cost of debt?

A. Cost of debt in the Company's proposed capital structure includes both long-term debt and long-term debt to affiliated trusts. Short-term debt carried on the Company's line of credit has been excluded from the capital structure. As shown on page 2 of Exhibit No. 201, the actual weighted average cost of total debt outstanding on December 31, 2006 was 7.74%. The size and mix of debt funding changes over time based upon the actual financing completed. We have made certain pro forma adjustments to update the debt cost through June 30, 2008 to 6.83%. Pro forma adjustments to long-term debt reflect expected maturities of outstanding debt. For example, the debt cost related to the 9.75% senior unsecured notes due June 1, 2008 has been excluded from the June 30, 2008 debt cost calculation. Avista has included a pro forma adjustment that reflects the refinancing of the 9.75% notes with new debt at an interest rate of 7.03%. The pro forma weighted cost of debt was reduced from 3.68% to 3.01% (excluding long-term debt to affiliated trusts).

VII. COST OF COMMON EQUITY

Q. What rate of return on common equity is the company proposing in this proceeding?

A. The company is proposing an 11.0% return on common equity (ROE), which is close to the lower end of Dr. Avera's recommended range of required return on equity. Dr. Avera testifies to analyses related to the cost of common equity for a proxy group of utilities with an ROE range of 10.75% to 11.75%.

Q. Dr. Avera suggests that an ROE above the midpoint of 10.75% to 11.75% is reasonable. Why is Avista requesting an ROE less than the midpoint of 11.25%?

A. As I have testified, the Company has made progress in its efforts to regain financial health. If Avista can earn an 11.0% ROE in 2008, I believe the financial results should support a stronger bond rating within a reasonable period of time.

Furthermore, as the Company has worked toward improving its financial condition over the last several years, it has done so with the customer in mind. Avista has attempted to balance the time frame for financial recovery with the impacts that increased retail rates have on its customers.

In this case, although we believe an ROE greater than 11.0% is supported and is warranted, we also believe the 11.0% provides a reasonable balance of the competing objectives of improving our financial condition within a reasonable period of time, and the impacts that increased rates have on our customers.

Q. Please summarize the proposed capital structure and the cost components for debt and common equity.

A. As also shown on page 2 of Exhibit No. 201, the following table shows the capital structure and cost components proposed by the Company.

PROFORMA Cost of Capital as of June 30, 2008	Amount	Percent of Total Capital	Cost	Component
Long-term Debt (1)	$926,024,214	44.09%	6.83%	3.01%
Long-term Debt to Affiliated Trusts	100,000,000	4.76%	7.04%	0.34%
Common Equity	1,074,144,875	51.15%	**11.00%** (2)	5.63%
TOTAL	$2,100,169,089	100.00%		**8.98%**

Q. Has Avista considered the impact the Company's current natural gas tracking mechanism will have on the requested return on equity?

A. Yes, the Company has considered the impact that the current natural gas tracking mechanism would have on the Company's requested return on equity. My discussions with investors and rating agencies indicate that this type of mechanism is viewed favorably by the investment community; however, this has not changed their views on Avista's overall investment risk or return on equity. The absence of a decoupling mechanism or a weather adjustment mechanism for Avista in Oregon, however, does imply greater investment risk.

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

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

MALYN K. MALQUIST
Exhibit No. 201

Financial Overview, Capital Structure and Overall Rate of Return

AVISTA CORPORATION

Long-term Securities Credit Ratings

	Standard & Poor's		Moody's		Fitch	
Last Reviewed	September 2007		March 2004		August 2007	
Credit Outlook	Positive		On review for potential upgrade		Positive	
Business Profile	5		N/A		N/A	
	AAA		Aaa		AAA	
	AA+		Aa1		AA+	
	AA		Aa2		AA	
	AA-		Aa3		AA-	
	A+		A1		A+	
	A		A2		A	
	A-		A3		A-	
	BBB+	First Mortgage Bonds Secured Medium-Term Notes	Baa1		BBB+	
	BBB		Baa2		BBB	First Mortgage Bonds Secured Medium-Term Notes
	BBB-		baa3	First Mortgage Bonds Secured Medium-Term Notes	BBB-	Unsecured Medium-Term Notes Senior Corporate Notes 9.75%
	INVESTMENT GRADE					
	BB+	Avista Corp./Corporate rating Unsecured Medium-Term Notes Senior Corporate Notes 9.75%	Ba1	Avista Corp./Issuer rating Unsecured Medium-Term Notes Senior Corporate Notes 9.75%	BB+	Avista Corp./Issuer rating Preferred Stock Trust-Originated Preferred Securities
	BB		Ba2	Trust-Originated Preferred Securities	BB	
	BB-	Preferred Stock Trust-Originated Preferred Securities	Ba3	Preferred Stock	BB-	

AVISTA CORPORATION

Capital Structure and Overall Rate of Return

PROFORMA

Cost of Capital as of June 30, 2008	Amount	Percent of Total Capital	Cost	Component
Long-term Debt	$926,024,214	44.09%	6.83%	3.01%
Long-term Debt to Affiliated Trusts	100,000,000	4.76%	7.04%	0.34%
Common Equity	1,074,144,875	51.15%	**11.00%** (1)	5.63%
TOTAL	$2,100,169,089	100.00%		**8.98%**

EMBEDDED

Cost of Capital as of December 31, 2006	Amount	Percent of Total Capital	Cost	Component
Long-term Debt	$970,171,924	47.58%	7.74%	3.68%
Long-term Debt to Affiliated Trusts	100,000,000	4.90%	7.20%	0.35%
Preferred Stock	26,250,000	1.29%	7.39%	0.10%
Common Equity	$942,748,776	46.23%	10.25%	4.74%
TOTAL	2,039,170,700	100.00%		**8.87%**

(1) Proposed Return on Common Equity - See Avera testimony

AVISTA CORPORATION

Long-term Securities Credit Ratings

	Standard & Poor's		Moody's		Fitch	
Last Reviewed	September 2007		March 2004		August 2007	
Credit Outlook	Positive		On review for potential upgrade		Positive	
Business Profile	5		N/A		N/A	
	AAA		**Aaa**		**AAA**	
	AA+		**Aa1**		**AA+**	
	AA		**Aa2**		**AA**	
	AA-		**Aa3**		**AA-**	
	A+		**A1**		**A+**	
	A		**A2**		**A**	
	A-		**A3**		**A-**	
	BBB+	First Mortgage Bonds Secured Medium-Term Notes	**Baa1**		**BBB+**	
	BBB		**Baa2**		**BBB**	First Mortgage Bonds Secured Medium-Term Notes
	BBB-		**baa3**	First Mortgage Bonds Secured Medium-Term Notes	**BBB-**	Unsecured Medium-Term Notes Senior Corporate Notes 9.75%
	INVESTMENT GRADE					
	BB+	Avista Corp./Corporate rating Unsecured Medium-Term Notes Senior Corporate Notes 9.75%	**Ba1**	Avista Corp./Issuer rating Unsecured Medium-Term Notes Senior Corporate Notes 9.75%	**BB+**	Avista Corp./Issuer rating Preferred Stock Trust-Originated Preferred Securities
	BB		**Ba2**	Trust-Originated Preferred Securities	**BB**	
	BB-	Preferred Stock Trust-Originated Preferred Securities	**Ba3**	Preferred Stock	**BB-**	

AVISTA CORPORATION
Capital Structure and Overall Rate of Return

PROFORMA

Cost of Capital as of June 30, 2008	Amount	Percent of Total Capital	Cost	Component
Long-term Debt	$926,024,214	44.09%	6.83%	3.01%
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Common Equity	$942,748,776	46.23%	10.25%	4.74%
TOTAL	2,039,170,700	100.00%		**8.87%**

(1) Proposed Return on Common Equity - See Avera testimony

Exhibit 300
Avera

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF WILLIAM E. AVERA
REPRESENTING THE AVISTA CORPORATION

Return on Equity

DIRECT TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the 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 Appendix A.

A. Overview

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 fair rate of return on equity ("ROE") for the jurisdictional gas utility operations of Avista Corp. ("Avista" or "the Company").

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. 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 corporate disclosures and management discussions, 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 investors' ROE requirements for Avista as it competes to attract capital, and form the basis of my analyses and conclusions.

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

A. The rate of return serves to compensate investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors will only commit money if the anticipated return on an investment is commensurate with returns available from other investment alternatives having comparable risks. Consistent with both sound regulatory economics and the standards specified in the *Bluefield*[1] and *Hope*[2] cases, the OPUC should allow a return on investment that is sufficient to: 1) fairly compensate 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.

Q. How did you develop your conclusions regarding a fair rate of return for Avista?

A. I first reviewed the operations and finances of Avista and the general conditions in the gas utility industry and the economy. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative

[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).

applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), as well as reference to comparable earned rates of return expected for utilities. Based on the cost of equity estimates indicated by my analyses, the Company's ROE was evaluated taking into account the specific risks and economic requirements for Avista consistent with restoration and preservation of its financial integrity.

B. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for Avista?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend that Avista be authorized an ROE in the range of 10.75 percent to 11.75 percent. The bases for my conclusion are summarized below:

- Considering investors' expectations for capital markets and the need to support financial integrity and fund capital investment even under adverse circumstances, it is my opinion that an ROE in the 10.75 percent to 11.75 percent range is reasonable for Avista. Specifically, I concluded that:
    - DCF estimates for alternative groups of proxy companies implied a cost of equity range of 10.2 percent to 12.4 percent;
    - A forward-looking application of the CAPM that best reflects the underlying assumptions of this approach resulted in a cost of equity for a proxy group of gas utilities of 11.6 percent, while applying the CAPM using historical data implied a required return of 11.1 percent;
    - Application of the risk premium approach based on realized rates of return for gas distribution utilities produced an estimated cost of equity of 10.5 percent;
    - Reference to expected earned rates of return for utilities implied an ROE in the 11.5 percent to 12.0 percent range;
    - Considering these results and my assessment of the relative strengths and weaknesses inherent in each method, I concluded that my quantitative analyses implied a "bare-bones" cost of equity in the 10.5 percent to 11.5 percent range;
    - Incorporating a 25 basis-point allowance for equity flotation costs resulted in an ROE range for the gas utility proxy group of 10.75 percent to 11.75

percent, with a midpoint of 11.25 percent;

- The reasonableness of an ROE in the 10.75 percent to 11.75 percent range is also supported by the greater risks associated with the Company's lower credit ratings, the lack of a weather normalization adjustment mechanism ("WNA") in Oregon for Avista, and the fact that, unlike some utilities in Oregon, Avista does not benefit from an elasticity or decoupling mechanism that provides recovery of fixed costs as customer usage changes.

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

A. Avista is requesting that a capital structure composed of approximately 44.1 percent long-term debt, 4.8 percent preferred securities, and 51.1 percent common equity be used to calculate the overall rate of return in this case, based on the Company's proforma capitalization as of June 30, 2008. My evaluation demonstrated that this capital structure represents a reasonable basis from which to calculate Avista's overall rate of return. This conclusion was based on the following findings:

- Avista's proforma common equity ratio is entirely consistent with the range of capital structures maintained by the gas distribution utilities in the proxy group, especially after considering the implications of off-balance sheet commitments and the trend towards lower financial leverage expected for the industry;
- Avista's requested capitalization is consistent with the Company's progress in strengthening its credit standing and financial flexibility as it seeks to raise additional capital to fund system investments and refinance outstanding securities;
- For a utility with an obligation to provide reliable service, ongoing industry uncertainties highlight the necessity of preserving flexibility, even during periods of adverse capital market conditions.

Q. What other evidence did you consider in evaluating your recommendation in this case?

A. My recommendation was reinforced by the following findings:

- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;

- Avista must compete for investors' capital with other utilities and businesses of comparable risk. If Avista is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital;
- Providing Avista with the opportunity to earn a return that reflects these realities is an essential ingredient to strengthen the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs;
- As discussed in the testimony of Malyn K. Malquist, Avista must access the capital markets to fund significant capital expenditures to maintain and enhance its utility system and is faced with the near-term prospect of refinancing a significant portion of its total debt outstanding;
- The challenges that have recently characterized the utility industry illustrate the need to ensure that Avista has the ability to respond effectively to unforeseen events.

Considering the importance of maintaining reliable and economical utility service and the damage that results when a utility's financial flexibility is compromised, supportive regulation is perhaps more crucial now than at any time in the past.

II. Fundamental Analysis

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews Avista's operations and finances and examines the risks and prospects for the natural gas industry as a whole. An understanding of the fundamental factors driving the risks and prospects of gas utilities is essential in developing an informed opinion of investors' expectations and requirements, which form the basis of a fair rate of return.

A. Avista

Q. Briefly describe the operations and finances of Avista.

A. Avista is engaged primarily in the procurement, transmission, and distribution of natural gas and electric energy, as well as other energy-related businesses. The Avista

Utilities operating division is comprised of state-regulated utility activities, including retail natural gas and electric distribution and transmission services and energy generation. In addition to providing gas distribution service in 4,000 square miles of northeast and southwest Oregon, Avista's utility segment also provides natural gas and electric utility service within a 26,000 square mile area of eastern Washington and northern Idaho.

Q. Please describe Avista's gas utility operations.

A. At December 31, 2006, Avista supplied natural gas to approximately 306,000 customers in parts of Oregon, Idaho, and Washington. Natural gas sales to residential customers accounted for approximately 60 percent of total retail revenues, while commercial customers made up 34 percent. Avista transports gas for large industrial customers, which purchase their own natural gas requirements through other parties. Several of Avista's largest natural gas customers are served under individual transportation contracts, which are subject to regulatory review and approval. During 2006, transportation sales accounted for approximately 28 percent of total natural gas deliveries. Avista obtains its gas supply from a variety of domestic and Canadian sources, through both long-term and spot market purchases. As well as owning a one-third interest in the Jackson Prairie natural gas storage facilities, Avista has entered into a three-year agreement with Northwest Natural Gas Company to obtain storage service from its Mist facility and has contracted for capacity delivery rights on five pipelines. Avista's retail gas distribution operations are subject to the jurisdiction of the OPUC, WUTC, and the IPUC. While Avista has natural gas trackers in place that allow it to pass-through a portion of changes in natural gas costs to customers, it currently does not have any adjustment mechanisms to adjust for the impact of abnormal weather on earnings, or for price elasticity effects on retail loads.

Q. Does Avista anticipate the need to access the capital markets going forward?

A. Most definitely. Avista will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its natural gas utility systems, as well as fund new investment in electric generation, transmission and distribution facilities. As noted in the testimony of Mr. Malquist, Avista's capital expenditures are expected to total approximately $416 million over 2007-2008. In addition to funding investment in utility infrastructure, Avista will also be required to refinance a significant portion of its long-term debt outstanding. In December 2006, Avista issued $150.0 million of long-term bonds to defease debt that was scheduled to mature in January 2007.[3] Also in December 2006, Avista received net proceeds of $77.7 million from the sale of approximately 3.2 million shares of common stock. Avista has $370 million of long-term debt maturities and mandatory preferred stock redemptions in 2007 and 2008 and will need to issue new securities to fund a significant portion of these requirements.

Continued support for Avista's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner and will also support the Company's efforts to refinance securities at favorable terms, thereby lowering costs for customers in the future. Strengthening Avista's financial flexibility is essential to

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[3] Avista's outstanding preferred stock matured in September 2007.

guarantee access to the cash resources and interim financing required to cover operating cash flows, as well as fund required investments in the utility system.

Q. What credit ratings have been assigned to Avista?

A. Avista is currently assigned a corporate credit rating of "BB+" by Standard & Poor's Corporation ("S&P"), with Avista's senior secured debt being rated "BBB+". Similarly, Moody's Investors Service ("Moody's") has assigned an issuer credit rating of "Ba1" to Avista and rates the Company's first mortgage bonds "Baa3", while Fitch Ratings, Ltd. ("Fitch") has assigned an issuer default rating of "BB+" and a senior secured debt rating of "BBB". These corporate credit ratings place Avista in the same category as speculative, or "junk," bond companies, with its senior debt ratings occupying the bottom rung on the ladder of the investment grade scale.

Q. What does Avista's credit rating imply with respect to the rate of return required by investors?

A. Cost of equity estimates developed for the two benchmark groups described subsequently are predicated on the investment risks associated with the proxy firms, which have average corporate credit ratings of "A-" and "A+". Meanwhile, Avista's below investment grade rating is indicative of an entirely different risk class. Because investors require a higher rate of return to compensate them for bearing more risk, the greater investment risk implied by Avista's credit ratings suggests that the cost of equity is correspondingly higher than for the proxy groups.

Q. Does the recently announced sale of Avista Energy, Inc. significantly alter Avista's relative investment risks?

A. No. On July 2, 2007 Avista closed the sale of substantially all of the assets and operations related to its energy trading and marketing activities of Avista Energy, Inc. to Coral Energy Holdings, L.P. Proceeds from the sale are estimated to total approximately $175 million, the majority of which are expected to be reinvested in Avista's utility operations.

The investment community views the sale of Avista Energy Inc.'s trading and marketing operations positively, but it has not resulted in a significant shift in Avista's risks relative to the proxy companies used to estimate the cost of equity. For example, while Moody's and S&P concluded that the sale implied a lower business risk profile, the change was not sufficient to warrant any immediate modification to Avista's credit standing. And while both rating agencies revised their outlook on Avista from "stable" to "positive" in response to the announced sale, they noted that any improvement in Avista's credit standing would be contingent on stronger financial performance, which remains weak compared to benchmark levels, and successfully meeting the challenges posed by higher capital spending and regulatory uncertainty.[4]

[4] Standard & Poor's Corporation, "Avista Corp.'s Rating Outlook Revised to Positive On Announced Intent To Sell Avista Energy," *RatingsDirect* (Apr. 17, 2007); Moody's Investors Service, "Moody's reviews Avista's rtgs. For possible upgrade," *Global Credit Research* (June 22, 2007).

B. Natural Gas Utility Industry

Q. What general conditions have characterized the natural gas industry over the last two decades?

A. Beginning in approximately 1980, the natural gas industry was buffeted by decreasing demand and prices, a gas glut, an ever-changing federal regulatory environment, and increased competition among participants and with other fuels. These developments spawned striking structural changes, not only within the pipeline segment of the industry, but for natural gas local distribution companies as well. At least initially, this process was largely driven by regulatory reforms at the federal level, with FERC being an aggressive proponent for actions designed to foster greater competition in markets for wholesale energy supply. While the FERC aspired to make the natural gas industry more competitive and broaden the market for gas supplies through its Order Nos. 436, 500, and 636, this dramatic restructuring also introduced considerable uncertainties and dislocations felt heavily by conventional utility systems.

These structural changes on both the demand and supply sides of the natural gas industry have created new uncertainties for market participants. Both pipelines and local gas distribution companies ("LDCs") have experienced "bypass" as large commercial, industrial, and wholesale customers seek to acquire gas supplies at the lowest possible cost and, in the process, abandon traditional "full-service" utility suppliers. The dramatic structural changes within the natural gas industry have forced LDCs to confront new complexities and risks entailed in actively contracting for an economical, secure gas supply. Further, changes in transportation rate design mandated by FERC Order No. 636 shifted greater cost responsibility for pipeline demand costs to low load factor customers and, particularly, LDCs who purchase transportation services from interstate pipelines. Coupled with an increasingly competitive market environment, these structural changes have resulted in greater business risk and operating leverage.

Q. What other factors are of concern to investors?

A. In recent years LDCs and their customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets. For example, the Energy Information Agency ("EIA") reported that the average city gate price of natural gas in Oregon increased 37 percent over the 12-month period ending October 2005.[5] During January 2007, the average city gate price fell by 9 percent compared with a year earlier, while June 2007 saw an increase of 11 percent from the previous year. S&P recognized that price spikes can "encourage users to substitute alternative fuels and discourage potential new customers from choosing natural gas,"[6] and concluded that:

> [C]urrent high gas prices will remain a challenge for all LDCs and may further pressure ratings for those LDCs that have a negative outlook and whose financial measures are somewhat stretched for their current rating.[7]

Fitch highlighted the challenges that fluctuations in commodity prices can have for utilities and their investors, observing that higher gas prices "depress consumer demand."[8]

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[5] Energy Information Administration, *Natural Gas Monthly* (August 2007), available at http:// www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_monthly/ngm.html.
[6] Standard & Poor's Corporation, "Natural Gas Distribution", *Industry Surveys*, p. 1 (Nov. 29, 2001).
[7] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk For U.S. Gas Distribution Companies," *RatingsDirect* (Jan. 17, 2006).
[8] Fitch Ratings, Ltd., "Outlook 2005: U.S. Power & Gas," *Global Power / North American*

Moody's recently echoed this sentiment, concluding that rising natural gas prices represent a challenge for LDCs because of reduced demand and margins.[9] As a result, a senior Fitch analysts concluded that investors "should exercise greater caution" when evaluating companies in the gas utility sector.[10] This becomes especially relevant when the utility does not benefit from a WNA or decoupling mechanism, as is the case for Avista's jurisdictional gas utility operations.

Q. Do recent conditions ameliorate investors' concerns regarding the potential for gas price volatility?

A. No. Investors recognize that the continuing prospect of further turmoil in energy markets cannot be discounted. S&P concluded that "natural gas prices have proven to be very volatile" and warned of a "turbulent journey" due to the uncertainty associated with future fluctuations in energy costs.[11] Fitch also highlighted the challenges that fluctuations in commodity prices can have for utilities and their investors, concluding, "Historically high and volatile commodity prices will continue to affect nearly the entire power and gas sector."[12] S&P noted that "volatile and high" natural gas prices will "remain a challenge for all LDCs" and are contributing to a negative credit outlook for natural gas distribution utilities.[13]

Special Report (Jan. 6, 2005) at 16.

[9] Moody's Investors Service, "North American Natural Gas Transmission & Distribution," *Industry Outlook* (Sep. 2007).

[10] Lapson, Ellen, "Rising Unit Costs & Credit Quality: Warning Signals," *Public Utilities Fortnightly* (Feb. 1, 2006).

[11] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[12] Fitch Ratings, Ltd., "U.S. Power and Gas 2007 Outlook," *Global Power North American Special Report* (Dec. 15, 2006) at 1.

[13] Standard & Poor's Corporation, "Key Credit Factors For U.S. Natural Gas Distributors,"

Similarly, the OPUC Staff noted that "the dynamics and operation of the US and Northwest natural gas markets have changed dramatically," and concluded that these developments "have placed great pressure on state commissions as well as the LDCs."[14] Concerns over the changed circumstances in the natural gas markets prompted the Staff to question the ability of the state's current gas trackers to accommodate the risks of today's more volatile markets:

> The Oregon PGA mechanism in place today was designed to meet LDC needs in a stable, lower priced, and more predictable natural gas market. That market no longer exists.[15]

The result is an ongoing investigation into potential modifications to the gas cost tracker mechanisms for LDCs in Oregon.

Q. Do the potential exposures faced by gas utilities highlight the need for ongoing support of a utility's financial strength and ability to attract capital?

A. Yes. Given the potential for significant volatility in natural gas markets and a utility's lack of control over the timing of such events, LDCs must have the wherewithal to meet these challenges even when energy market conditions are unfavorable. Considering investors' heightened awareness of the risks associated with high and volatile gas prices, supportive regulation remains crucial in preserving financial integrity and access to capital under reasonable terms. S&P affirmed that regulatory decisions have become a "dominant factor" in their assessment of credit quality,[16] and concluded that "[c]ontinued regulatory support is

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RatingsDirect (Feb. 28, 2006)
[14] Public Utility Commission of Oregon, *Staff Report* (Nov. 21, 2006).
[15] *Id.*
[16] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric/Water/Gas,"

paramount to credit quality for LDCs, especially during periods of prolonged high natural gas prices."[17] Moody's recently echoed these sentiments, noting that "regulatory relationships are becoming more important" in an era of rising costs and uncertainties.[18]

Q. Are these the only risks faced by natural gas distribution utilities?

A. No. Apart from these factors, the industry continues to face the normal risks inherent in operating utility systems, including potential adverse effects of inflation, interest rate changes, growth, and the general economy. As a senior analyst for Fitch noted:

> Capital expenditures are on the rise for network reliability, mandated environmental compliance, and resource adequacy. Utilities face rising non-fuel operating and maintenance expenses, particularly for pensions, employee medical expenses, and post-retirement benefits. A trend of declining interest expenses that benefited the sector over the past four years is likely to reverse in the next several years… In Fitch's view, the sector's credit recovery is now fading, and investors should exercise greater caution regarding the power and gas sector.[19]

III. CAPITAL STRUCTURE

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

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RatingsDirect (May 3, 2005).
[17] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk For U.S. Gas Distribution Companies," *RatingsDirect* (Jan. 17, 2006).
[18] Moody's Investors Service, "Regulatory Pressures Increase for U.S. Electric Utilities," *Special Comment* (March 2007).
[19] Lapson, Ellen, "Rising Unit Costs & Credit Quality: Warning Signals," *Public Utilities*

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 will be used to establish the company's overall rate of return?

A. Avista's proposed capitalization is based on its pro-forma capital structure at June 30, 2008. As discussed in the testimony of Mr. Malquist, this capital structure consists of approximately 44.1 percent long-term debt, 4.8 percent preferred securities, and 51.1 percent common equity.

Q. How does this compare with common equity ratios maintained by other gas utilities?

A. In evaluating Avista's capital structure, and in estimating the cost of equity, it is customary to examine data for publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with Avista's jurisdictional gas utility operations, my analyses focused on a reference group of other publicly traded LDCs included by The Value Line Investment Survey ("Value Line") in their Natural Gas Utility industry group. Excluded from the group was one firm that is in the process of being acquired (SEMCO Energy, Inc.). Given that these twelve utilities are all engaged in gas utility operations and classified by Value Line as gas utilities, investors are likely to regard this group as facing similar market conditions and having comparable risks and prospects.

Fortnightly (Feb. 1, 2006).

Schedule WEA-1 presents capital structure ratios for the gas utility proxy group. As shown there, common equity ratios for the individual firms in the proxy group of gas utilities ranged from a low of 35.0 percent to a high of 64.9 percent at year-end 2006, with the average being 50.2 percent.

Q. What implication does the increasing risk of the utility industry have for the capital structures maintained by utilities?

A. The challenges imposed by the evolving structural changes in the industry imply that utilities will be required to incorporate relatively greater amounts of equity in their capital structures. A more conservative financial profile is consistent with increasing uncertainties and the need to maintain continuous access to capital under reasonable terms, as required to fund operations and necessary system investment, even during times of adverse capital market conditions. As Fitch noted:

> Companies that form growth plans and financial structures without considering the potential for a shift in the capital market environment or downturn in valuations can run into financial problems down the road.[20]

As shown on Schedule WEA-1, Value Line expects that the average common equity ratio for the proxy group of gas utilities will increase to 56.5 percent over the next three to five years, with the individual common equity ratios ranging from 46.0 percent to 72.7 percent.

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[20] Fitch Ratings, Ltd., "U.S. Power and Gas 2007 Outlook," *Global Power/North America Special Report* (Dec. 15, 2006).

Q. What other factors do investors consider in their assessment of capital structure?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating Avista's financial risk. For example, S&P reaffirmed its practice of adjusting reported results to reflect the debt equivalent impact of operating leases, post-retirement benefit obligations, and asset retirement obligations, among other factors.[21] Additionally, because energy purchase agreements typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. Further, changes in financial accounting standards also result in adjustments that have the effect of further increasing financial leverage. Because bond ratings agencies and investors adjust for these various commitments in assessing a utility's financial position, they imply greater risk and reduced financial flexibility.

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

A. Based on my evaluation, I concluded that a capital structure consisting of approximately 51.1 percent common equity represents a reasonable mix of capital sources from which to calculate Avista's overall rate of return. The Company's proposed common equity ratio is entirely consistent with the capitalizations maintained by the gas utility proxy

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[21] Standard & Poor's Corporation, "Credit FAQ: S&P Introduces Reconciliation Tables to Show Analytical Adjustments To Global Utilities' Financial Statements," *RatingsDirect* (Oct.

group at year-end 2006, and falls below the average equity ratio expected for the industry over the next three to five years. Moody's recently noted the financial pressures associated with planned infrastructure investments in an environment of rising costs. Moody's went on to warn of the risks associated with increasing debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[22]

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has large capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

Q. Are these legitimate concerns for Avista?

A. Yes. As noted earlier, the Company anticipates that new investment in utility infrastructure will total approximately $416 million over the 2007-2008 period alone. In addition, Avista is also in the process of refinancing a significant portion of its long-term debt. Coupled with the fact that the Company's corporate credit ratings remain outside the investment grade tier, reduced financial leverage is responsive to the investment community's concerns and the Company's efforts to rebuild its financial condition. Avista's capital

11, 2006).

[22] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North

structure reflects the Company's ongoing efforts to improve its credit standing and support access to capital on reasonable terms.

IV. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. In this section, a fair rate of return on common equity for Avista is developed. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe quantitative analyses conducted to estimate the cost of equity for reference groups of comparable risk firms.

A. Economic Standards

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

A. The return on common equity is the cost of inducing and retaining equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They 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. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment 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

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American Electric Utility Sector," *Special Comment* (Aug. 2007).

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 this cost of equity concept?

A. Underlying the concept of the cost of equity is the fundamental notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for doing so. The required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk. Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

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

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. As discussed earlier, the securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is therefore the least risky. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's cash flow, such as debentures and notes, followed by preference stockholders. The last investors in line are common shareholders. They only receive the cash flow, if any, that remains 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, is considerably higher than the yield on the utility's long-term debt.

Q. Is the cost of equity observable in the capital markets?

A. No. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Because it is unobservable, the cost of 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' current 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. As the FCC recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superceded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[23]

[23] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

Similarly, the OPUC has also considered the results of alternative methods in establishing allowed ROEs for utilities under its jurisdiction. Therefore, I used both the DCF and CAPM methods to estimate the cost of equity. In addition, I also evaluated a fair ROE using the risk premium and expected earnings approaches. 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 are DCF models used to estimate the cost of 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. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q. What market valuation process underlies DCF models?

A. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return.

Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form. This constant growth form of the DCF model is customarily used to estimate the cost of equity in rate cases:

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

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
K_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

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

The constant growth 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 price appreciation.

Q. Are the assumptions underlying the constant growth form of the DCF model met in the real world?

A. The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met.[24] Nevertheless, where earnings are

[24] 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

derived from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model offers a reasonable working approximation of stock valuation that provides useful insight as to investors' required rate of return.

Q. How did you implement the DCF model to estimate the cost of equity for Avista's jurisdictional gas utility operations?

A. In estimating the cost of equity, the DCF model is typically applied to publicly traded firms engaged in similar business activities. In order to reflect the risks and prospects associated with Avista's gas utility operations, my DCF analyses focused on the same group of twelve publicly traded gas utilities identified earlier; namely, those firms included in Value Line's Natural Gas Utility industry that were not engaged in a merger.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of 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 sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

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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. How was the dividend yield for the reference group of LDCs determined?

A. Estimates of dividends to be paid by each of these natural gas utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock price, and resulting dividend yields for the firms in the gas distribution proxy group are presented on Schedule WEA-2. As shown there, dividend yields for the fourteen firms in the LDC group ranged from 1.3 percent to 4.6 percent, with the average being 3.5 percent.

Q. How is the growth component of the constant DCF model measured?

A. 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 and have embodied in current stock prices. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this 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.[25] 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.

[25] For example, the payout ratio for electric utilities fell from approximately 80% historically to on the order of 60%. [The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 9,

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

A. As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations.

The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[26]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[27]

2007 at 1774)]

[26] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).

[27] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

The fact that investment advisory services, such as Value Line, I/B/E/S International, Inc. ("IBES"), Reuters, Inc. ("Reuters"), Zack's Investment Research (Zack's), and the Thompson Corporation's First Call service ("First Call") focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[28] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[29]

More recently, the Financial Analysts Journal reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[30]

Q. What are security analysts currently projecting in the way of growth for the firms in the gas utility proxy group?

A. The earnings growth projections for each of the firms in the utility proxy group reported by IBES and published in S&P's *Earnings Guide* are displayed on Schedule WEA-2.

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[28] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[29] *Id.* at 88.
[30] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.

Also presented are the earnings per share ("EPS") growth projections reported by Value Line, Reuters, Zack's, and First Call. The average of five the alternative EPS growth projections for each utility are shown in column (g) of Schedule WEA-2.[31]

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

A. Based on the assumptions underlying constant growth theory, conventional applications of the constant growth DCF model often examine the relationship between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. 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.

Q. What is the purpose of the "sv" term?

A. 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. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

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[31] In addition to publishing data for individual utilities, Zack's and First Call also report projected growth rates for the gas utility industry of 6.9 percent and 7.4 percent, respectively.

Q. How did you apply the earnings retention method for the proxy group of gas utilities?

A. The sustainable, "br+sv" growth rates for each firm in the proxy group are summarized on Schedule WEA-2, with the underlying details being presented on Schedule WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What cost of equity estimates were implied for the gas utility proxy group using the constant growth DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of equity estimates are shown in columns (i) and (j) of Schedule WEA-2.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate cost of equity estimates that fail to meet threshold tests of economic logic?

A. Yes. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. 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 senior, long-term debt. Consistent with this principle, the DCF range for the proxy group of utilities must be adjusted to eliminate cost of equity estimates that fail fundamental tests of economic logic.

Q. Have similar tests been applied by regulators?

A. Yes. The FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[32]

More recently, in its October 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

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[32] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at 22.

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[33]

FERC upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[34]

Q. What does this test of reasonableness indicate with respect to the constant growth DCF estimates for the gas utility proxy group?

A. The average bond rating associated with the firms in the proxy group is single-A, with Moody's monthly yields on single-A bonds averaging approximately 6.24 percent during August 2007.[35] In the present instance, three of the individual cost of equity estimates exceeded this threshold by 120 basis points or less.[36] In light of the risk-return tradeoff principle, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, these values provide little guidance as to the returns investors require from the common stock of a gas utility.

Q. What other objective evidence demonstrates that cost of equity estimates of 7.4 percent or less are not logical?

A. Expectations regarding future trends in long-term capital costs further supports a finding that these estimates are illogical and should be disregarded. The most recent

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[33] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 (2006) at P. 140 & fn. 227.
[34] *Id.*
[35] Moody's *Credit Perspectives* (Sep. 10, 2007).
[36] As highlighted on Schedule WEA-2, three DCF estimates ranged from 6.5 percent to 7.4 percent.

forecast of GlobalInsight, a widely referenced forecasting service, calls for double-A public utility bond yields to reach 6.98 percent in 2008 and average 7.22 percent over the five years ended 2012.[37] Meanwhile, the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy, anticipates that the double-A public utility bond yield will reach 6.85 percent in 2008, or an average of 7.30 percent for the period 2008-2012.[38] As shown in Table 1 below, with the average yield spread between double-A and single-A utility bonds over the six months ended August 2007 being 14 basis points, these forecasts imply an average single-A bond yield of 7.35 percent for 2008, or 7.69 percent over the 5-year period 2008-2012:

[37] GlobalInsight, "The U.S. Economy: The 30-Year Focus" (Third-Quarter 2006) at Table 34. This is the only series of projections for public utility bond yields reported by GlobalInsight.
[38] Energy Information Administration, "Annual Energy Outlook 2007," (Feb. 2007) at Table 19. This is the only series of projections for public utility bond yields reported by EIA.

TABLE 1
IMPLIED BBB BOND YIELD

Line No.		2008	2008-12
1	Projected AA Utility Yield		
2	GlobalInsight (a)	6.24%	6.71%
3	EIA (b)	6.85%	7.30%
4	Average	6.55%	7.01%
5	A – AA Yield Spread (c)	0.14%	0.14%
6	Implied A Utility Yield	6.69%	7.15%

(a) GlobalInsight, "The U.S. Economy: The 30-Year Focus" (First-Quarter 2007) at Table 34.

(b) Energy Information Administration, "Annual Energy Outlook 2007," (Feb. 2007) at Table 19.

(c) Based on monthly average bond yields for the six months Mar. – Aug. 2007 reported in Moody's *Credit Perspectives*.

Given that equity estimates of 7.4 percent or less are essentially equal to or below investors' expectations for comparable utility bond yields, these cannot be considered credible estimates of investors' required return on common stocks.

Q. What cost of equity is implied by your constant growth DCF results for the gas utility proxy group?

A. As shown on Schedule WEA-2, after eliminating illogical values, application of the constant growth DCF model resulted in average cost of equity estimates based on EPS and br+sv growth rates of 9.0 percent and 10.5 percent, respectively.

Q. Are there any alternatives to the constant growth DCF model?

A. Yes, there are. The constant growth form is a simplified version of the general DCF model:

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

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 equity.

The general, or multi-state form of the DCF model can be used to estimate the cost of equity by substituting projections for a firm's future dividends (D_t) and price (P_t) for the variables in the equation, and imputing the cost of equity (K_e) by equating the future cash flows to the current price (P_0).

Q. Did you apply the multi-stage DCF model to estimate the cost of equity for the LDC group?

A. Yes. As noted above, the multi-stage DCF model entails estimating the dividends investors expect to receive from holding a share of stock and the price that they expect to sell it for at some point in the future. My application of the multi-stage DCF model to the gas utility proxy group was based on a five year holding period (2007-2011) corresponding to Value Line's forecast horizon.

As shown on Schedule WEA-4, expected dividends (D_t) during this holding period were based on Value Line's forecasts of 2007, 2008 and 2010-2012 dividends, with values for intervening years being interpolated. The future stock price (P_t) was calculated based on the constant growth DCF formula:

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

Expected dividends in the terminal year (D_1) were calculated by multiplying Value Line's forecasted 2010-2012 dividend payment by ($1 + g$), where g is equal to the sustainable, br+sv growth rate implied by Value Line's projections.[39] The cost of equity was then estimated by imputing the discount rate necessary to equate the projected dividends and stock price to the recent price (P_0) reported by Value Line for each of the companies in the gas utility proxy group. This approach, which considers both investors' near-term expectations for dividend cash flows and expectations for future capital gains, is consistent with similar approaches presented in the financial literature.[40]

Q. What cost of equity estimates were produced using this multi-stage DCF model?

A. As shown on Schedule WEA-4, after eliminating illogical values,[41] the cost of equity estimates produced by this application of the multi-stage DCF model averaged 10.2 percent.

Q. What considerations are relevant in evaluating these DCF results for gas utilities?

A. The short-term projected growth rates and data used to apply the DCF model may be colored by lingering economic uncertainties and the numerous challenges faced in the

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[39] The derivation of the projected br+sv growth rates for each of the firms in the gas utility proxy group is shown on Schedule WEA-3.

[40] See, *e.g.*, Brigham, Eugene F., Shome, Dilip K., and Vinson, Steve R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985) at 37.

[41] As discussed earlier and highlighted on Schedule WEA-4, the 6.7 percent cost of equity estimate produced for Piedmont Natural Gas Company is not sufficiently higher than the yield on single-A utility bonds to be considered a meaningful estimate of investors' required ROE.

utility industry. The impact of this short-term focus is exemplified by Value Line, which has assigned its Utilities sector the lowest ranking of all 10 sectors it covers for year-ahead stock price performance.[42] As a result, a cautious short-term outlook may be indicative of relatively low near-term growth projections; but it does not necessarily reflect investors' long-term expectations for the industry.

Prospects for mergers and acquisitions also complicate estimating the cost of equity using the DCF model because investors incorporate their expectations of capital appreciation when establishing the price they are willing to pay for gas utility stocks, but this potential price growth is not reflected into the growth rates or other projections typically used in DCF applications. As a result, investors' actual growth expectations are understated, which results in a corresponding understatement of the cost of equity.

Q. How else can the DCF model be applied to estimate the ROE for Avista?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy.

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[42] The Value Line Investment Survey, *Selection & Opinion* (July 6, 2007) at 4642.

Q. What criteria did you apply to evaluate investors' risk perceptions?

A. My assessment of comparable risk relied on three objective benchmarks for the risks associated with common stocks -- Value Line's Safety Rank, Financial Strength rating, and beta. The Safety Rank is Value Line's primary risk indicator and 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. 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. Beta reflects the tendency of a stock's price to follow changes in the market and, accordingly to modern portfolio theory, is the only relevant measure of investment risk. A stock that tends to respond relatively 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.

My non-utility proxy group was composed of those U.S. companies followed by Value Line that 1) pay common dividends, 2) have a Safety Rank of "1", 3) have a Financial Strength Rating of "A" or above, and 4) have beta values of 0.86 or less. In addition, I also eliminated firms with below-investment grade credit ratings. Table 2 compares the resulting group of 38 non-utility firms with the gas utility proxy group and Avista across four key indicators of investment risk:

TABLE 2
COMPARISON OF RISK INDICATORS

Line No.		S&P	Value Line		
		Credit Rating	Safety Rank	Financial Strength	Beta
1	Non-Utility Group	A+	1	A+	0.74
2	Gas Utility Proxy Group	A-	2	B++	0.86
3	Avista Corp.	BB+	3	B+	0.90

Considered along with S&P's corporate credit ratings, a comparison of these Value Line indicators, which encompass a broad spectrum of risk measures, demonstrates that the average investment risks associated with the non-utility group fall below those of the gas utility proxy group and Avista. Considering the fundamental tradeoff between risk and return discussed earlier, this comparison suggests that cost of equity estimates for the non-utility group should provide a conservative estimate of investors' required rate of return for Avista's gas utility operations.

Q. What were the results of your DCF analysis for the non-utility group?

A. I applied the DCF model to the non-utility companies in exactly the same manner described earlier for the utility proxy group. As shown on Schedule WEA-5, consistent with the discussion earlier, I eliminated a 6.7 percent cost of equity estimate because this value is not sufficiently higher than the available yields on long-term bonds. In addition, I also eliminated five cost of equity estimates at the high end of the range of DCF results. Compared with the balance of the remaining estimates, these high-end values – which ranged from 17.5 percent to 29.4 percent – could be considered outliers and should also be excluded in evaluating the results of the DCF model for the utility proxy group. After eliminating the illogical low- and high-end values highlighted on Schedule WEA-5, application of the constant growth DCF model resulted in average cost of equity estimates for the non-utility group of 12.4 percent and 13.2 percent.[43]

Q. What did you conclude with respect to the cost of equity implied by the proxy groups using the constant growth DCF model?

A. Taken together, I concluded that these DCF results for the two alternative proxy groups implied a cost of equity range of 10.2 percent to 12.4 percent.

Q. Do you believe the DCF model should be relied on exclusively to evaluate a reasonable ROE for Avista?

A. No. Because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is a blunt tool that should never be used exclusively. Regulators have customarily considered the results of alternative approaches in determining allowed returns.[44] It is widely recognized that no single method can be regarded as a panacea and all approaches have their own advantages and shortcomings. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and

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[43] Schedule WEA-6 contains the details underlying the calculation of the br+sv growth rates for the non-utility group.

[44] For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

> its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[45]

Moreover, evidence suggests that reliance on the DCF model as a tool for estimating investors' required rate of return has declined outside the regulatory sphere.[46] *Regulatory Finance: Utilities Cost of Capital* noted the inherent difficulties of the DCF approach:

> [C]aution and judgment are required in interpreting the results of DCF models because of (1) the questionable applicability of the DCF model to utility stocks in certain market environments, (2) the effect of declining earnings and dividends on financial inputs to the DCF model and biases caused by the effect of changes in risk and growth, and (3) the conceptual and practical difficulties associated with the growth component of the DCF model.[47]

The publication concluded, "If the cost of equity estimation process is limited to one methodology, such as DCF, it may severely bias the results."[48]

C. Capital Asset Pricing Model

Q Please describe the CAPM.

A. The CAPM is generally considered to be to most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Because investors

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[45] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.
[46] See, *e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," Financial Practice and Education (1998).
[47] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* (1994) at 238.

are assumed to be 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. 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 CAPM 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 CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

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

A. Application of the CAPM to the utility proxy group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Schedule WEA-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, with the growth rate being equal to the average of the earnings growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections

[48] *Id.*

for the 353 individual firms, current estimates imply an average growth rate over the next five years of 10.5 percent. Combining this average growth rate with a dividend yield of 2.2 percent results in a current cost of equity estimate for the market as a whole of approximately 12.7 percent. Subtracting a 5.0 percent risk-free rate based on the average yield on 20-year Treasury bonds for August 2007 produced a market equity risk premium of 7.7 percent. Multiplying this risk premium by the average Value Line beta of 0.86 for the utilities in the proxy group, and then adding the resulting 6.6 percent risk premium to the average long-term Treasury bond yield, indicated an ROE of approximately 11.6 percent.

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

A. I also applied the CAPM using risk premiums based on historical realized rates of return. This approach to estimating investors' equity risk premiums is premised on the assumption that investors form expectations of future stock returns based on observable debt yields and the historical experience of realized returns from common stock investments relative to debt investments. The historical record of returns, such as the Ibbotson data are frequently referenced in the financial media, pension fund reports, mutual fund prospectuses, and other sources familiar to investors. Thus, while historical returns do not predict the future, investors may use this historical record in determining whether the return offered by a utility stock is competitive with what might be earned from other investment alternatives.

While reference to historical data represents one way to apply the CAPM, these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. The cost of capital is a forward-looking, or expectational, concept that is focused on the perceptions of today's capital market investors. While past investment returns are frequently referenced and may provide a useful benchmark, the only factors that actually determine the current required rate of return are investors' expectations for the future. As a result, forward-looking applications of the CAPM that look directly at investors' expectations in the capital markets are apt to provide a more meaningful guide to investors' required rate of return.

Q. What CAPM cost of equity is produced based on historical realized rates of return for stocks and long-term government bonds?

A. I applied the CAPM using data published by Ibbotson Associates, which is perhaps the most exhaustive and widely referenced annual study of realized rates of return. Application of the CAPM based on historical realized rates of return is presented in Schedule WEA-8. In their *2007 Yearbook, Valuation Edition*, Ibbotson Associates reported that, over the period from 1926 through 2006, the arithmetic mean realized rate of return on the S&P 500 exceeded that on long-term government bonds by 7.1 percent.[49] Multiplying this historical market risk premium by the average Value Line beta of 0.86 produced an equity risk premium of 6.1 percent for the utility proxy group. As shown on Schedule WEA-8, adding this equity risk premium to the August 2007 average yield on 20-year Treasury bonds of 5.0 percent resulted in an implied cost of equity of 11.1 percent.

[49] Ibbotson Associates computes the equity risk premium by subtracting the income return (not the total return) on long-term Treasury bonds from the return on common stocks.

D. Risk Premium Method

Q. Please describe the risk premium method.

A. The risk premium method of estimating investors' required rate of return extends the risk-return tradeoff observed with bonds to 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 then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, the risk premium method directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. How did you implement the risk premium method?

A I based my estimate of equity risk premiums on realized rates of return for gas utilities. Under the realized-rate-of-return approach, equity risk premiums are calculated by measuring the rate of return (including, dividends, interest, and capital gains and losses) actually realized on an investment in common stocks and bonds over historical periods. The realized rate of return on bonds is then subtracted from the return earned on commons stocks to measure equity risk premiums.

Moody's *Public Utility Manual* published a consistent set of stock price and dividend data for a group of natural gas distribution utilities between the years 1952 and 2001. As shown on Schedule WEA-9, over this period realized rates of return for these utilities exceeded those on single-A public utility bonds by an average of 4.28 percent. Adding this 4.28 percent equity risk premium to the August 2007 average yield of 6.24 percent on single-A utility bonds produced a current cost of equity for the LDC proxy group of approximately 10.5 percent.

E. Expected Earnings Method

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

A. As I noted earlier, I also evaluated the cost of 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 Supreme Court. 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 rates of return on equity are indicated for utilities based on this approach?

A. With respect to expectations for utilities generally, Value Line reports that its analysts anticipate an average rate of return on common equity for natural gas utility industry of 11.5 percent in 2007 and 2008 and 12.0 percent over the years 2010 through 2012.[50] Meanwhile, Value Line expects that electric utilities will earn an average ROE of 11.5 percent in 2007, 2008 and over its three-to-five year forecast horizon.[51]

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[50] The Value Line Investment Survey (Sep. 14, 2007) at 445.
[51] The Value Line Investment Survey (Sep. 28, 2007) at 695.

For the gas utility proxy group specifically, the returns on common equity for these twelve firms projected by Value Line over its three-to-five year forecast horizon are shown on Schedule WEA-10. Consistent with the rational underlying the development of the br+sv growth rates discussed earlier, these year-end values were converted to average returns using the same adjustment factor developed in Schedule WEA-3. As shown on Schedule WEA-10, Value Line's projections suggested an average ROE of 12.1 percent.

Q. What return on equity is indicated by the results of the expected earnings approach?

A. Based on the results discussed above, I concluded that the expected earnings approach implies a fair rate of return on equity of 11.5 percent to 12.0 percent.

V. RECOMMENDED RETURN ON EQUITY

Q. What is the purpose of this section?

A. In addition to summarizing the results of my analyses, this section examines other factors that should be considered in evaluating a fair rate of return for the Company and presents my recommended ROE range for Avista.

A. Summary of Quantitative Results

Q. Please summarize the results of your quantitative analyses.

A. The cost of equity estimates implied by my quantitative analyses are summarized in Table 3 below:

TABLE 3
SUMMARY OF QUANTITATIVE RESULTS

Method	**Indicated Cost of Equity**
DCF	10.2% -- 12.4%
CAPM	
Forward-looking	11.6%
Historical	11.1%
Risk Premium	10.5%
Expected Earnings	11.5% -- 12.0%

Q. What then is your conclusion as to the cost of equity for the proxy group of gas utilities?

A. Based on the results of my quantitative analyses, and my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of equity for the gas utility proxy group is presently in the 10.5 to 11.5 percent range.

B. Flotation Costs

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. Alternatively, 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 logical mechanism.

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

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of 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.[52]

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.[53] Applying these expense percentages to a representative dividend yield for a utility of 3.5 percent implies a flotation cost adjustment on the order of 13 to 35 basis points.

Q. Is the need for a flotation cost adjustment to compensate for past equity issues recognized in the financial literature?

A. Yes. In a *Public Utilities Fortnightly* article, 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.[54] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing 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

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[52] Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 1994, at 166.
[53] *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%.
[54] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly* (May, 2, 1985).

> 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 most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[55]

Q. How do you propose to account for flotation costs in your recommended rate of return on equity?

A. As discussed above, I concluded that the "bare bones" cost of equity for an LDC is presently in the 10.5 to 11.5 percent range. This "bare bones" cost of equity, however, does not recognize flotation costs incurred in connection with past sales of common stock. Accordingly, I added a flotation cost adjustment of 25 basis points to arrive at a fair rate of return on equity range of 10.75 percent to 11.75 percent.

C. Other Factors

Q. How do Avista's investment risks compare to the reference groups used to estimate the cost of equity?

A. As noted earlier, the low triple-B ratings assigned to Avista's senior debt occupy the lowest rung on the investment grade ladder, with Avista's corporate credit falling below this critical threshold. Avista's credit ratings are indicative of significantly higher investment risks than the reference groups of gas utilities and non-utility firms, which have average corporate credit ratings of "A-" and "A+", respectively. Similarly, as illustrated

[55] Morin, Roger A., *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports (1994) at 175.

earlier in Table 2, a comparison of Value Line's key risk indicators for common stocks also confirms that investors would conclude that Avista's risks exceed those of the reference groups used to estimate the cost of equity. Because investors require a higher rate of return to compensate them for bearing more risk, the greater investment risks implied for Avista suggests that the cost of equity is correspondingly higher than for the proxy groups.

Q. How does the lack of a weather normalization adjustment impact Avista's rate of return on equity relative to the LDC group?

A. As indicated earlier, Avista does not have a weather normalization adjustment mechanism in place to account for the impacts of abnormal weather on its Oregon-jurisdictional gas utility operations. A WNA moderates the impact of extreme weather on customers and, at the same time, dampens the volatility of a gas utility's revenues. Indeed, virtually all of the twelve LDCs in the proxy group used to estimate the cost of equity have some form of weather mitigant, including adjustment clauses, insurance, or rate design features that make the LDC less susceptible to variations in gas consumption due to weather. As Value Line noted, "Any fluctuations that deviate too far from the historical norm can create volatility," concluding that "rate mechanisms are becoming increasingly common" in the gas utility industry.[56] As a result, while Avista remains exposed to the risks associated with abnormal weather, the reduced uncertainties associated with a WNA are at least partially accounted-for by investors and reflected in my cost of equity estimates.

[56] The Value Line Investment Survey (Sep. 14, 2007) at 445.

Q. What other considerations are relevant in determining a reasonable rate of return on equity for Avista's jurisdictional gas utility operations?

A. In evaluating a reasonable rate of return on equity, it is also important to note that, unlike some utilities in Oregon, Avista does not benefit from elasticity or decoupling mechanisms that insulate utility margins from declining usage. As the OPUC noted in its September 2002 Order adopting a proposed stipulation for NW Natural:

> The stipulation provides that an elasticity adjustment will be applied to the rates of all of NW Natural's residential and commercial customers beginning on October 1, 2002. ...This adjustment will help account for the affect that rate changes have on customers usage. Under this elasticity adjustment, NW Natural will recover, on a prospective basis only, the margin shortfalls in each customer category by developing rate increments and applying them in permanent rates for each class as of October 1, 2002.
>
> ...Also on October 1, 2002, NW Natural will implement a partial decoupling mechanism, under which it will defer and subsequently amortize 90 percent of the margin differentials in the residential and commercial customer groups.[57]

Avista's jurisdictional gas utility operations have experienced significant declines in customer usage – due in part to the impact of gas cost increases – that have translated into reduced margins. As a result, Avista's continued exposure to the uncertainties associated with the impact of price elasticity and other fluctuations in customer usage implies a level of risk in excess of that faced by other Oregon utilities.

[57] In the Matter of Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization, Public Utility Commission of Oregon, Order No. 02-634 (Sep. 12, 2002) at 3.

Q. What does this evidence suggest with respect to Avista's cost of equity relative to the proxy group results?

A. The higher investment risks associated with Avista's lower credit ratings, the Company's weakened credit standing and financial flexibility, and the lack of WNA or decoupling mechanism, all suggest that investors' required return for Avista exceeds that of the proxy groups used to estimate the cost of equity. Competition for capital resources is intense and investors are free to invest their funds wherever they choose. Denying investors the opportunity to earn a return that is commensurate with Avista's investment risks would perpetuate the Company's anemic credit standing and hamper its future ability to attract capital, especially during periods of adverse capital market conditions.

Q. Why is it important to allow Avista an adequate rate of return on equity?

A. Given the social and economic importance of the utility industry, it is essential to maintain reliable and economical service to all consumers. Providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, but it imposes additional financial responsibilities on incumbent utility suppliers, such as Avista. While Avista remains committed to deliver reliable service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of adverse capital market conditions highlights the necessity of preserving the flexibility. To continue to meet potential challenges successfully and economically, it is crucial that Avista receive support for its efforts to rebuild the Company's financial health and credit standing.

Q. Do customers also benefit by enhancing the utility's financial flexibility?

A. Yes. While providing an ROE that is sufficient to maintain Avista's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure delivery of a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised.

Q. What role does regulation play in ensuring Avista's access to capital?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to Avista's access to capital. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. S&P concluded that "[c]ontinued regulatory support is paramount to credit quality for LDCs," especially in light of continued high and volatile natural gas prices,[58] and more recently noted that:

> Regulatory rulings have returned to center stage as a dominant factor in assessing companies' credit quality. These decisions will be critical for an industry that in many jurisdictions is nearing the end of extended

[58] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005).

> transition periods and will be making significant capital investment in infrastructure during the next several years.[59]

With respect to Avista specifically, Moody's concluded that "[f]ailure to obtain adequate and timely support for recovery of and return on core utility investments" could have negative ratings implications.[60]

D. Summary and Conclusions

Q. What then is your conclusion as to the cost of equity for Avista?

A. Based on the results of my quantitative analyses, and my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of equity for the LDC proxy group is in the 10.5 percent to 11.5 percent range. After incorporating an adjustment for flotation costs of 25 basis points to my "bare bones" cost of equity range, I concluded that a fair rate of return on equity for the proxy group of utilities is currently in the 10.75 percent to 11.75 percent range. The relatively greater risks associated with Avista and its gas utility operations in Oregon would support an ROE above the 11.25 percent midpoint of this range.

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

A. Yes, it does.

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59 Standard & Poor's Corporation, "Industry Report Card: U.S. Electric/Gas/Water," *RatingsDirect* (May 3, 2005) at 1.
60 Moody's Investors Service, Credit Opinion: Avista Corp., *Global Credit Research* (Dec. 14, 2006).

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

WILLIAM E. AVERA
Exhibit No. 301

Return on Equity

GAS UTILITY PROXY GROUP

CAPITAL STRUCTURE

	At Fiscal Year-End 2006 (a)			Value Line Projected (b)		
Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
AGL Resources, Inc.	49.6%	0.0%	50.4%	49.0%	0.0%	51.0%
Atmos Energy Corp.	57.0%	0.0%	43.0%	51.0%	0.0%	49.0%
Laclede Group	49.5%	0.1%	50.4%	49.0%	0.0%	51.0%
New Jersey Resources	35.1%	0.0%	64.9%	27.3%	0.0%	72.7%
Nicor, Inc.	36.3%	0.0%	63.7%	33.0%	0.0%	67.0%
Northwest Natural Gas	47.7%	0.0%	52.3%	48.0%	0.0%	52.0%
Piedmont Natural Gas	48.3%	0.0%	51.7%	48.7%	0.0%	51.3%
South Jersey Industries	44.8%	0.0%	55.2%	42.5%	0.0%	57.5%
Southern Union Co.	60.6%	4.4%	35.0%	45.0%	3.5%	51.5%
Southwest Gas	61.1%	0.0%	38.9%	54.0%	0.0%	46.0%
UGI Corp.	61.6%	0.0%	38.4%	36.0%	0.0%	64.0%
WGL Holdings, Inc.	40.1%	1.8%	58.1%	32.9%	1.6%	65.5%
Average	**49.3%**	**0.5%**	**50.2%**	**43.0%**	**0.4%**	**56.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Sep. 14, 2007).

CONSTANT GROWTH DCF MODEL

GAS UTILITY PROXY GROUP

	(a)	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Dividend Yield			Growth Rates							Cost of Equity Estimates	
	Recent			Analyst Earnings Growth Projections							Projected	br+sv
Company	Price	Dividends	Yield	IBES	V. Line	Reuters	Zack's	First Call	Average	br+sv	EPS Growth	Growth
AGL Resources, Inc.	$ 40.11	$ 1.64	4.1%	5.0%	3.5%	5.0%	4.5%	4.9%	4.6%	6.4%	8.7%	10.5%
Atmos Energy Corp.	$ 28.16	$ 1.30	4.6%	5.0%	5.5%	5.4%	5.3%	5.6%	5.4%	6.1%	10.0%	10.7%
Laclede Group	$ 32.64	$ 1.49	4.6%	3.0%	2.0%	3.0%	3.0%	3.0%	2.8%	4.8%	7.4%	9.4%
New Jersey Resources	$ 48.33	$ 1.52	3.1%	5.0%	4.0%	5.4%	5.7%	5.7%	5.2%	5.3%	8.3%	8.5%
Nicor, Inc.	$ 42.08	$ 1.86	4.4%	5.0%	4.5%	3.8%	4.0%	2.0%	3.9%	4.6%	8.3%	9.1%
Northwest Natural Gas	$ 46.07	$ 1.48	3.2%	5.0%	7.0%	5.5%	5.3%	4.8%	5.5%	5.8%	8.7%	9.0%
Piedmont Natural Gas	$ 26.46	$ 1.00	3.8%	5.0%	4.5%	4.6%	5.3%	4.5%	4.8%	2.7%	8.6%	6.5%
South Jersey Industries	$ 34.02	$ 1.01	3.0%	7.0%	NMF	6.3%	7.0%	6.8%	6.8%	11.5%	9.7%	14.5%
Southern Union Co.	$ 30.00	$ 0.40	1.3%	8.0%	8.0%	7.5%	6.5%	8.4%	7.7%	8.3%	9.0%	9.6%
Southwest Gas	$ 29.11	$ 0.86	3.0%	5.0%	9.0%	4.3%	5.0%	4.5%	5.6%	9.8%	8.5%	12.7%
UGI Corp.	$ 25.74	$ 0.74	2.9%	8.0%	4.5%	8.0%	NA	8.0%	7.1%	10.8%	10.0%	13.7%
WGL Holdings, Inc.	$ 33.34	$ 1.37	4.1%	3.0%	2.0%	3.3%	3.0%	3.3%	2.9%	3.8%	7.0%	7.9%
Average (k)			**3.5%**								**9.0%**	**10.5%**

(a) The Value Line Investment Survey, *Summary and Index* (Sep. 14, 2007).
(b) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (Aug. 2007).
(c) The Value Line Investment Survey (Sep. 14, 2007).
(d) http://stocks.us.reuters.com (retrieved Sep. 12, 2007).
(e) http://zacks.com (retrieved Sep. 13, 2007).
(f) First Call growth rates from http://finance.yahoo.com (retrieved Sep. 13, 2007).
(g) Average of (b) through (f).
(h) See Schedule WEA-3.
(i) Sum of dividend yield and (g).
(j) Sum of dividend yield and (h).
(k) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

GAS UTILITY PROXY GROUP

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections			Historical		Mid-Year					
			Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
AGL Resources, Inc.	$3.10	$1.80	$22.50	$20.71	1.7%	1.0083	41.9%	13.9%	5.8%	0.54%	6.4%
Atmos Energy Corp.	$2.45	$1.35	$26.35	$20.16	5.5%	1.0268	44.9%	9.5%	4.3%	1.82%	6.1%
Laclede Group	$2.35	$1.60	$24.50	$18.85	5.4%	1.0262	31.9%	9.8%	3.1%	1.70%	4.8%
New Jersey Resources	$3.35	$1.84	$33.25	$22.50	8.1%	1.0390	45.1%	10.5%	4.7%	0.59%	5.3%
Nicor, Inc.	$2.90	$1.86	$23.05	$19.43	3.5%	1.0171	35.9%	12.8%	4.6%	0.04%	4.6%
Northwest Natural Gas	$3.20	$1.86	$26.35	$22.01	3.7%	1.0180	41.9%	12.4%	5.2%	0.65%	5.8%
Piedmont Natural Gas	$1.70	$1.16	$13.60	$11.83	2.8%	1.0139	31.8%	12.7%	4.0%	-1.34%	2.7%
South Jersey Industries	$2.85	$1.20	$17.95	$15.11	3.5%	1.0172	57.9%	16.2%	9.4%	2.16%	11.5%
Southern Union Co.	$2.35	$0.56	$25.60	$15.20	11.0%	1.0521	76.2%	9.7%	7.4%	0.91%	8.3%
Southwest Gas	$2.70	$0.90	$25.25	$21.58	3.2%	1.0157	66.7%	10.9%	7.2%	2.55%	9.8%
UGI Corp.	$2.45	$0.76	$17.45	$10.43	10.8%	1.0514	69.0%	14.8%	10.2%	0.61%	10.8%
WGL Holdings, Inc.	$2.30	$1.52	$22.70	$18.28	4.4%	1.0217	33.9%	10.4%	3.5%	0.24%	3.8%

(a) The Value Line Investment Survey (Sep. 14, 2007).
(b) Annual growth in book value per share from historical to projected period
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio)
(h) (f) + (g).

GAS UTILITY PROXY GROUP

MULTI-STAGE DCF MODEL

		Future Stock Price								Annual Cash Flows						Implied
	Recent	2010-12	Terminal	Proj.	Future	2007	2008	2010-12	Annual							Cost of
Company	Price	DPS	"g"	D_1	Price	Div.	Div.	Div.	Change	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	End Yr 5	Equity
AGL Resources, Inc.	$40.11	$1.80	6.4%	$1.91	$51.03	$ 1.64	$ 1.64	$ 1.80	$0.05	$ 0.41	$ 1.64	$ 1.69	$ 2.10	$ 1.80	$ 51.03	10.1%
Atmos Energy Corp.	$28.16	$1.35	6.1%	$1.43	$35.22	$ 1.28	$ 1.30	$ 1.35	$0.02	$ 0.32	$ 1.30	$ 1.32	$ 1.64	$ 1.35	$ 35.22	10.2%
Laclede Group	$32.64	$1.60	4.8%	$1.68	$39.05	$ 1.45	$ 1.49	$ 1.60	$0.04	$ 0.36	$ 1.49	$ 1.53	$ 1.89	$ 1.60	$ 39.05	9.1%
New Jersey Resources	$48.33	$1.84	5.3%	$1.94	$59.55	$ 1.52	$ 1.60	$ 1.84	$0.08	$ 0.38	$ 1.60	$ 1.68	$ 2.06	$ 1.84	$ 59.55	8.6%
Nicor, Inc.	$42.08	$1.86	4.6%	$1.95	$49.65	$ 1.86	$ 1.86	$ 1.86	$0.00	$ 0.47	$ 1.86	$ 1.86	$ 2.33	$ 1.86	$ 49.65	8.6%
Northwest Natural Gas	$46.07	$1.86	5.8%	$1.97	$58.16	$ 1.44	$ 1.52	$ 1.86	$0.11	$ 0.36	$ 1.52	$ 1.63	$ 1.99	$ 1.86	$ 58.16	9.2%
Piedmont Natural Gas	$26.46	$1.16	2.7%	$1.19	$29.34	$ 1.00	$ 1.04	$ 1.16	$0.04	$ 0.25	$ 1.04	$ 1.08	$ 1.33	$ 1.16	$ 29.34	6.7%
South Jersey Industries	$34.02	$1.20	11.5%	$1.34	$52.95	$ 0.98	$ 1.04	$ 1.20	$0.05	$ 0.25	$ 1.04	$ 1.09	$ 1.34	$ 1.20	$ 52.95	14.0%
Southern Union Co.	$30.00	$0.56	8.3%	$0.61	$41.88	$ 0.40	$ 0.44	$ 0.56	$0.04	$ 0.10	$ 0.44	$ 0.48	$ 0.58	$ 0.56	$ 41.88	9.7%
Southwest Gas	$29.11	$0.90	9.8%	$0.99	$42.31	$ 0.86	$ 0.86	$ 0.90	$0.01	$ 0.22	$ 0.86	$ 0.87	$ 1.09	$ 0.90	$ 42.31	12.1%
UGI Corp.	$25.74	$0.76	10.8%	$0.84	$38.77	$ 0.75	$ 0.76	$ 0.76	$0.00	$ 0.19	$ 0.76	$ 0.76	$ 0.95	$ 0.76	$ 38.77	13.0%
WGL Holdings, Inc.	$33.34	$1.52	3.8%	$1.58	$38.38	$ 1.36	$ 1.40	$ 1.52	$0.04	$ 0.34	$ 1.40	$ 1.44	$ 1.78	$ 1.52	$ 38.38	7.9%
Average																10.2%

Source: The Value Line Investment Survey (Sep. 14, 2007).

DISCOUNTED CASH FLOW MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Growth Rates							Cost of Equity Estimates	
		Dividend	Analyst Earnings Growth Projections							Projected	br+sv
	Company	Yield	IBES	V. Line	Reuters	Zack's	First Call	Average	br+sv	EPS Growth	Growth
1	3M Company	2.12%	11%	5.0%	11.1%	11.1%	11.1%	9.9%	16.1%	12.0%	18.2%
2	Abbott Labs.	2.46%	12%	9.5%	10.6%	10.6%	12.0%	10.9%	14.2%	13.4%	16.7%
3	Aflac Inc.	1.52%	15%	12.5%	14.2%	13.8%	14.5%	14.0%	13.1%	15.5%	14.6%
4	Anheuser-Busch	2.66%	9%	7.0%	9.0%	8.8%	8.6%	8.5%	26.8%	11.1%	29.4%
5	Automatic Data Proc.	1.99%	15%	9.5%	13.5%	13.3%	14.9%	13.2%	10.2%	15.2%	12.2%
6	Bard (C.R.)	0.71%	14%	14.0%	14.2%	14.0%	14.2%	14.1%	12.7%	14.8%	13.4%
7	Becton, Dickinson	1.27%	13%	11.5%	12.5%	13.0%	12.7%	12.5%	13.3%	13.8%	14.5%
8	Coca-Cola	2.49%	9%	9.0%	9.2%	8.8%	9.2%	9.0%	9.4%	11.5%	11.9%
9	Colgate-Palmolive	2.18%	11%	11.0%	10.6%	10.8%	10.7%	10.8%	20.9%	13.0%	23.1%
10	Ecolab Inc.	1.10%	14%	13.0%	14.8%	14.5%	14.4%	14.1%	18.6%	15.2%	19.7%
11	Fortune Brands	2.05%	10%	6.0%	9.7%	10.8%	9.7%	9.2%	10.5%	11.3%	12.6%
12	Gannett Co.	3.34%	7%	3.5%	5.6%	6.6%	5.7%	5.7%	7.7%	9.0%	11.0%
13	Gen'l Mills	2.71%	8%	7.0%	8.5%	8.5%	8.1%	8.0%	6.6%	10.7%	9.3%
14	Genuine Parts	3.00%	9%	9.5%	9.3%	8.9%	9.3%	9.2%	9.5%	12.2%	12.5%
15	Harte-Hanks	1.18%	11%	7.5%	10.5%	10.2%	10.7%	10.0%	12.2%	11.2%	13.3%
16	Heinz (H.J.)	3.34%	7%	8.0%	7.8%	7.6%	7.4%	7.6%	12.3%	10.9%	15.6%
17	Hershey Co.	2.60%	9%	7.0%	8.9%	9.0%	9.1%	8.6%	14.9%	11.2%	17.5%
18	Hormel Foods	1.68%	10%	10.5%	9.5%	8.8%	9.5%	9.7%	12.8%	11.3%	14.5%
19	Johnson & Johnson	2.69%	8%	8.0%	9.1%	9.2%	7.9%	8.4%	10.9%	11.1%	13.6%
20	Kimberly-Clark	3.09%	7%	5.5%	7.6%	8.3%	7.5%	7.2%	10.3%	10.3%	13.4%
21	Kraft Foods	3.24%	7%	5.5%	7.5%	7.1%	7.4%	6.9%	5.2%	10.1%	8.4%
22	Lilly (Eli)	2.96%	8%	7.0%	8.0%	8.2%	7.6%	7.8%	11.7%	10.7%	14.7%
23	Lockheed Martin	1.42%	11%	15.0%	10.1%	9.5%	11.5%	11.4%	15.4%	12.8%	16.9%
24	Medtronic, Inc.	0.93%	13%	12.5%	14.2%	14.0%	13.8%	13.5%	14.2%	14.4%	15.2%
25	Meredith Corp.	1.33%	12%	11.5%	11.8%	11.8%	11.8%	11.8%	11.3%	13.1%	12.6%
26	PepsiCo, Inc.	2.19%	11%	10.5%	11.4%	11.2%	11.0%	11.0%	10.4%	13.2%	12.6%
27	Pfizer, Inc.	4.71%	5%	2.0%	7.7%	7.4%	4.2%	5.2%	2.0%	10.0%	6.7%
28	Procter & Gamble	2.12%	11%	10.5%	11.6%	11.6%	11.7%	11.3%	6.1%	13.4%	8.2%

DISCOUNTED CASH FLOW MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Growth Rates							Cost of Equity Estimates	
		Dividend	Analyst Earnings Growth Projections							Projected	br+sv
	Company	Yield	IBES	V. Line	Reuters	Zack's	First Call	Average	br+sv	EPS Growth	Growth
29	Sara Lee Corp.	2.48%	8%	-1.0%	7.1%	7.1%	6.7%	5.6%	10.8%	8.1%	13.3%
30	Sysco Corp.	2.30%	13%	11.5%	13.3%	12.3%	13.4%	12.7%	13.4%	15.0%	15.7%
31	United Parcel Serv.	2.24%	12%	9.0%	11.4%	11.2%	11.6%	11.1%	12.9%	13.3%	15.1%
32	UnitedHealth Group	0.06%	15%	15.0%	15.2%	15.1%	15.5%	15.2%	12.3%	15.2%	12.4%
33	Wal-Mart Stores	2.06%	12%	10.0%	12.4%	11.8%	12.2%	11.7%	11.5%	13.8%	13.5%
34	Walgreen Co.	0.84%	15%	15.0%	15.3%	15.3%	15.3%	15.2%	13.9%	16.0%	14.8%
35	Washington Federal	3.21%	8%	10.5%	7.4%	7.0%	7.9%	8.2%	9.8%	11.4%	13.0%
36	Washington Post	1.04%	9%	5.5%	9.4%	16.9%	7.7%	9.7%	8.2%	10.7%	9.2%
37	Wells Fargo	3.48%	11%	10.5%	11.2%	11.3%	10.9%	11.0%	11.2%	14.4%	14.7%
38	Wrigley (Wm.) Jr.	1.94%	11%	9.0%	10.4%	10.1%	10.5%	10.2%	11.0%	12.1%	12.9%
	Average (k)									**12.4%**	**13.2%**

(a) www.valueline.com (retrieved Sep. 14, 2007).
(b) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (Aug. 2007).
(c) www.valueline.com (retrieved Sep. 14, 2007).
(d) http://stocks.us.reuters.com (retrieved Sep. 14, 2007).
(e) http://zacks.com (retrieved Sep. 16, 2007).
(f) First Call growth rates from http://finance.yahoo.com (retrieved Sep. 16, 2007).

NON-UTILITY PROXY GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
1	3M Company	$5.80	$2.28	$21.70	$13.56	9.9%	1.0470	60.7%	28.0%	17.0%	-0.89%	16.1%
2	Abbott Labs.	$4.20	$1.60	$17.60	$9.14	14.0%	1.0654	61.9%	25.4%	15.7%	-1.50%	14.2%
3	Aflac Inc.	$5.20	$1.32	$26.90	$16.93	9.7%	1.0463	74.6%	20.2%	15.1%	-1.97%	13.1%
4	Anheuser-Busch	$3.90	$1.28	$7.75	$5.11	8.7%	1.0416	67.2%	52.4%	35.2%	-8.43%	26.8%
5	Automatic Data Proc.	$3.00	$1.15	$17.20	$10.71	9.9%	1.0473	61.7%	18.3%	11.3%	-1.05%	10.2%
6	Bard (C.R.)	$6.35	$0.86	$32.75	$16.46	14.8%	1.0687	86.5%	20.7%	17.9%	-5.21%	12.7%
7	Becton, Dickinson	$5.60	$1.60	$29.75	$15.63	13.7%	1.0643	71.4%	20.0%	14.3%	-1.04%	13.3%
8	Coca-Cola	$3.70	$1.84	$12.10	$7.30	10.6%	1.0505	50.3%	32.1%	16.1%	-6.74%	9.4%
9	Colgate-Palmolive	$5.00	$2.16	$10.40	$2.32	35.0%	1.1489	56.8%	55.2%	31.4%	-10.45%	20.9%
10	Ecolab Inc.	$2.65	$0.65	$10.20	$6.69	8.8%	1.0422	75.5%	27.1%	20.4%	-1.87%	18.6%
11	Fortune Brands	$7.15	$1.76	$54.05	$31.08	11.7%	1.0553	75.4%	14.0%	10.5%	0.01%	10.5%
12	Gannett Co.	$6.00	$1.84	$53.80	$35.71	8.5%	1.0410	69.3%	11.6%	8.0%	-0.38%	7.7%
13	Gen'l Mills	$4.30	$2.00	$19.05	$16.21	3.3%	1.0161	53.5%	22.9%	12.3%	-5.66%	6.6%
14	Genuine Parts	$4.25	$1.90	$23.50	$14.95	9.5%	1.0452	55.3%	18.9%	10.5%	-0.91%	9.5%
15	Harte-Hanks	$2.00	$0.40	$12.50	$6.58	13.7%	1.0641	80.0%	17.0%	13.6%	-1.47%	12.2%
16	Heinz (H.J.)	$3.60	$1.88	$10.00	$5.72	11.8%	1.0558	47.8%	38.0%	18.2%	-5.87%	12.3%
17	Hershey Co.	$3.30	$1.50	$3.90	$2.97	5.6%	1.0272	54.5%	86.9%	47.4%	-32.51%	14.9%
18	Hormel Foods	$3.30	$0.80	$20.60	$13.13	9.4%	1.0450	75.8%	16.7%	12.7%	0.15%	12.8%
19	Johnson & Johnson	$5.50	$2.04	$25.95	$13.59	13.8%	1.0646	62.9%	22.6%	14.2%	-3.27%	10.9%
20	Kimberly-Clark	$5.20	$2.76	$17.90	$13.38	6.0%	1.0291	46.9%	29.9%	14.0%	-3.73%	10.3%
21	Kraft Foods	$2.60	$1.00	$22.65	$17.45	5.4%	1.0261	61.5%	11.8%	7.2%	-2.05%	5.2%
22	Lilly (Eli)	$4.50	$2.20	$17.30	$9.70	12.3%	1.0578	51.1%	27.5%	14.1%	-2.35%	11.7%
23	Lockheed Martin	$10.00	$2.25	$39.30	$16.35	19.2%	1.0875	77.5%	27.7%	21.4%	-6.00%	15.4%
24	Medtronic, Inc.	$4.35	$0.83	$17.75	$9.60	13.1%	1.0614	80.9%	26.0%	21.0%	-6.82%	14.2%
25	Meredith Corp.	$4.80	$0.90	$29.45	$14.49	15.2%	1.0708	81.3%	17.5%	14.2%	-2.91%	11.3%
26	PepsiCo, Inc.	$4.85	$1.95	$15.65	$9.36	10.8%	1.0514	59.8%	32.6%	19.5%	-9.06%	10.4%
27	Pfizer, Inc.	$2.30	$1.36	$12.25	$9.98	4.2%	1.0205	40.9%	19.2%	7.8%	-5.82%	2.0%
28	Procter & Gamble	$4.60	$1.90	$33.45	$19.33	11.6%	1.0548	58.7%	14.5%	8.5%	-2.45%	6.1%

NON-UTILITY PROXY GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
29	Sara Lee Corp.	$1.20	$0.45	$3.80	$3.22	3.4%	1.0166	62.5%	32.1%	20.1%	-9.22%	10.8%
30	Sysco Corp.	$2.70	$1.10	$7.75	$4.93	9.5%	1.0452	59.3%	36.4%	21.6%	-8.22%	13.4%
31	United Parcel Serv.	$5.75	$2.00	$27.25	$14.47	13.5%	1.0632	65.2%	22.4%	14.6%	-1.74%	12.9%
32	UnitedHealth Group	$5.70	$0.05	$25.10	$15.47	10.2%	1.0484	99.1%	23.8%	23.6%	-11.26%	12.3%
33	Wal-Mart Stores	$4.75	$1.15	$24.40	$14.91	10.4%	1.0492	75.8%	20.4%	15.5%	-4.03%	11.5%
34	Walgreen Co.	$3.50	$0.48	$20.45	$10.04	15.3%	1.0710	86.3%	18.3%	15.8%	-1.88%	13.9%
35	Washington Federal	$2.90	$1.00	$19.40	$14.46	6.1%	1.0294	65.5%	15.4%	10.1%	-0.25%	9.8%
36	Washington Post	$47.45	$9.70	$483.90	$330.20	7.9%	1.0382	79.6%	10.2%	8.1%	0.07%	8.2%
37	Wells Fargo	$4.10	$1.44	$23.75	$13.58	11.8%	1.0558	64.9%	18.2%	11.8%	-0.63%	11.2%
38	Wrigley (Wm.) Jr.	$3.20	$1.38	$14.95	$8.65	11.6%	1.0547	56.9%	22.6%	12.8%	-1.88%	11.0%

(a) www.valueline.com (retrieved Sep. 17, 2007).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

CAPITAL ASSET PRICING MODEL

FORWARD-LOOKING RISK PREMIUM

Market Rate of Return		
Dividend Yield (a)	2.2%	
Growth Rate (b)	10.5%	
Market Return (c)		12.7%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		5.0%
Market Risk Premium (e)		7.7%
Utility Proxy Group Beta (f)		0.86
Utility Proxy Group Risk Premium (g)		6.6%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		5.0%
Implied Cost of Equity (h)		**11.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Aug. 28, 2007).

(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's Earnings Guide (Aug. 2007) and www.valueline.com (Retreived Aug. 28, 2007).

(c) (a) + (b)

(d) Average yield on 20-year Treasury bonds for Aug. 2007 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.

(e) (c) - (d).

(f) The Value Line Investment Survey (Sep. 14, 2007)

(g) (e) x (f).

(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

HISTORICAL RISK PREMIUM

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.1%
Utility Proxy Group Beta (b)	0.86
Utility Proxy Group Risk Premium (c)	6.1%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	5.0%
Implied Cost of Equity (e)	**11.1%**

(a) Arithmetic mean risk premium on Large Company Stocks from 1926-2006 reported by Morningstar, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2007 Yearbook*, at Appendix C, Table C-1, p. 262.
(b) The Value Line Investment Survey (Sep. 14, 2007)
(c) (a) x (b).
(d) Average yield on 20-year Treasury bonds for Aug. 2007 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) + (d).

REALIZED RETURNS

	Moody's Gas Distribution Stocks (a)			Moody's Single-A Utility Bonds (b)
	DEC PRICE	DIV	Annual Realized Return	Income Return
1952	$20.57			3.22%
1953	$21.23	$1.09	8.51%	3.38%
1954	$26.47	$1.19	30.29%	3.11%
1955	$28.10	$1.32	11.14%	3.35%
1956	$28.23	$1.43	5.55%	3.91%
1957	$25.78	$1.49	-3.40%	4.36%
1958	$38.71	$1.53	56.09%	4.49%
1959	$39.59	$1.63	6.48%	4.96%
1960	$48.21	$1.79	26.29%	4.65%
1961	$64.96	$1.91	38.71%	4.65%
1962	$59.73	$2.01	-4.96%	4.44%
1963	$64.62	$2.13	11.75%	4.46%
1964	$68.24	$2.27	9.11%	4.54%
1965	$64.31	$2.40	-2.24%	4.83%
1966	$53.50	$2.75	-12.53%	5.67%
1967	$50.49	$2.67	-0.64%	6.67%
1968	$53.80	$2.79	12.08%	6.87%
1969	$43.88	$2.88	-13.09%	8.59%
1970	$52.33	$2.97	26.03%	8.48%
1971	$47.86	$3.06	-2.69%	7.90%
1972	$53.54	$3.10	18.35%	7.48%
1973	$43.43	$3.21	-12.89%	8.24%
1974	$29.71	$3.31	-23.97%	10.27%
1975	$38.29	$3.43	40.42%	10.11%
1976	$51.80	$3.65	44.82%	8.62%
1977	$50.88	$3.85	5.66%	8.64%
1978	$45.97	$4.07	-1.65%	9.70%
1979	$53.50	$4.33	25.80%	11.79%
1980	$56.61	$4.59	14.39%	14.63%
1981	$53.50	$4.95	3.25%	16.29%
1982	$50.62	$5.28	4.49%	14.43%
1983	$55.79	$5.45	20.98%	13.52%
1984	$69.70	$5.71	35.17%	13.11%
1985	$76.58	$6.06	18.57%	10.97%
1986	$90.89	$5.68	26.10%	9.12%
1987	$77.25	$5.86	-8.56%	10.98%
1988	$86.76	$6.15	20.27%	10.06%
1989	$117.05	$6.45	42.35%	9.44%
1990	$108.86	$6.70	-1.27%	9.73%
1991	$124.32	$6.94	20.58%	8.88%
1992	$138.79	$7.08	17.33%	8.43%
1993	$154.06	$7.23	16.21%	7.34%
1994	$126.96	$7.36	-12.81%	8.76%
1995	$155.94	$7.48	28.72%	7.23%
1996	$166.64	$7.76	11.84%	7.59%
1997	$191.04	$7.99	19.44%	7.16%
1998	$177.24	$8.12	-2.97%	6.91%
1999	$166.84	$8.18	-1.25%	8.14%
2000	$200.68	$8.22	25.21%	7.84%
2001	$203.07	$8.22	5.29%	7.83%
AVERAGE 1953-2001			**12.29%**	**8.01%**

Realized Rates of Return	
Moody's Gas Distribution	12.29%
Single-A Public Utility Bonds	8.01%
Equity Risk Premium	4.28%
Aug. 2007 Single-A Utility Bond Yield (c)	6.24%
Implied Cost of Equity	**10.52%**

(a) Mergent *Public Utility Manual* (2002); Mergent *Public Utility News Reports* (Jan. 15, 2002).

(b) Average yield for December from Mergent *Public Utility Manual* (2003).

(c) Moody's *Credit Perspectives* (Sep. 10, 2007).

EXPECTED EARNINGS APPROACH

GAS UTILITY PROXY GROUP

Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
AGL Resources, Inc.	14.0%	1.0083	14.1%
Atmos Energy Corp.	9.0%	1.0268	9.2%
Laclede Group	10.0%	1.0262	10.3%
New Jersey Resources	10.5%	1.0390	10.9%
Nicor, Inc.	13.0%	1.0171	13.2%
Northwest Natural Gas	11.5%	1.0180	11.7%
Piedmont Natural Gas	12.5%	1.0139	12.7%
South Jersey Industries	15.5%	1.0172	15.8%
Southern Union Co.	10.5%	1.0521	11.0%
Southwest Gas	10.5%	1.0157	10.7%
UGI Corp.	14.0%	1.0514	14.7%
WGL Holdings, Inc.	10.5%	1.0217	10.7%
Average			**12.1%**

(a) 3-5 year projections from The Value Line Investment Survey (Sep. 14, 2007)
(b) See Schedule WEA-3. An adjustment is necessary to reflect Value Line's use of year-end capital balances
(c) (a) x (b).

APPENDIX A

QUALIFICATIONS OF WILLIAM E. AVERA

Q. What is the purpose of this exhibit?

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

Q. What are your qualifications?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the United States Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission, as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 30 states.

In 1995, I was appointed by the PUCT, with the approval of the Governor, to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered

Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I also have served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners (NARUC) Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I also have served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in 240 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 40 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (80 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

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"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

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Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

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"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

GAS UTILITY PROXY GROUP

CAPITAL STRUCTURE

	At Fiscal Year-End 2006 (a)			Value Line Projected (b)		
Company	**Long-term Debt**	**Preferred**	**Common Equity**	**Long-term Debt**	**Other**	**Common Equity**
AGL Resources, Inc.	49.6%	0.0%	50.4%	49.0%	0.0%	51.0%
Atmos Energy Corp.	57.0%	0.0%	43.0%	51.0%	0.0%	49.0%
Laclede Group	49.5%	0.1%	50.4%	49.0%	0.0%	51.0%
New Jersey Resources	35.1%	0.0%	64.9%	27.3%	0.0%	72.7%
Nicor, Inc.	36.3%	0.0%	63.7%	33.0%	0.0%	67.0%
Northwest Natural Gas	47.7%	0.0%	52.3%	48.0%	0.0%	52.0%
Piedmont Natural Gas	48.3%	0.0%	51.7%	48.7%	0.0%	51.3%
South Jersey Industries	44.8%	0.0%	55.2%	42.5%	0.0%	57.5%
Southern Union Co.	60.6%	4.4%	35.0%	45.0%	3.5%	51.5%
Southwest Gas	61.1%	0.0%	38.9%	54.0%	0.0%	46.0%
UGI Corp.	61.6%	0.0%	38.4%	36.0%	0.0%	64.0%
WGL Holdings, Inc.	40.1%	1.8%	58.1%	32.9%	1.6%	65.5%
Average	**49.3%**	**0.5%**	**50.2%**	**43.0%**	**0.4%**	**56.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Sep. 14, 2007).

CONSTANT GROWTH DCF MODEL

GAS UTILITY PROXY GROUP

	(a)	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Dividend Yield			**Growth Rates**							**Cost of Equity Estimates**	
	Recent			**Analyst Earnings Growth Projections**							**Projected**	**br+sv**
Company	**Price**	**Dividends**	**Yield**	**IBES**	**V. Line**	**Reuters**	**Zack's**	**First Call**	**Average**	**br+sv**	**EPS Growth**	**Growth**
AGL Resources, Inc.	$ 40.11	$ 1.64	4.1%	5.0%	3.5%	5.0%	4.5%	4.9%	4.6%	6.4%	8.7%	10.5%
Atmos Energy Corp.	$ 28.16	$ 1.30	4.6%	5.0%	5.5%	5.4%	5.3%	5.6%	5.4%	6.1%	10.0%	10.7%
Laclede Group	$ 32.64	$ 1.49	4.6%	3.0%	2.0%	3.0%	3.0%	3.0%	2.8%	4.8%	7.4%	9.4%
New Jersey Resources	$ 48.33	$ 1.52	3.1%	5.0%	4.0%	5.4%	5.7%	5.7%	5.2%	5.3%	8.3%	8.5%
Nicor, Inc.	$ 42.08	$ 1.86	4.4%	5.0%	4.5%	3.8%	4.0%	2.0%	3.9%	4.6%	8.3%	9.1%
Northwest Natural Gas	$ 46.07	$ 1.48	3.2%	5.0%	7.0%	5.5%	5.3%	4.8%	5.5%	5.8%	8.7%	9.0%
Piedmont Natural Gas	$ 26.46	$ 1.00	3.8%	5.0%	4.5%	4.6%	5.3%	4.5%	4.8%	2.7%	8.6%	6.5%
South Jersey Industries	$ 34.02	$ 1.01	3.0%	7.0%	NMF	6.3%	7.0%	6.8%	6.8%	11.5%	9.7%	14.5%
Southern Union Co.	$ 30.00	$ 0.40	1.3%	8.0%	8.0%	7.5%	6.5%	8.4%	7.7%	8.3%	9.0%	9.6%
Southwest Gas	$ 29.11	$ 0.86	3.0%	5.0%	9.0%	4.3%	5.0%	4.5%	5.6%	9.8%	8.5%	12.7%
UGI Corp.	$ 25.74	$ 0.74	2.9%	8.0%	4.5%	8.0%	NA	8.0%	7.1%	10.8%	10.0%	13.7%
WGL Holdings, Inc.	$ 33.34	$ 1.37	4.1%	3.0%	2.0%	3.3%	3.0%	3.3%	2.9%	3.8%	7.0%	7.9%
Average (k)			**3.5%**								**9.0%**	**10.5%**

(a) The Value Line Investment Survey, *Summary and Index* (Sep. 14, 2007).
(b) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (Aug. 2007).
(c) The Value Line Investment Survey (Sep. 14, 2007).
(d) http://stocks.us.reuters.com (retrieved Sep. 12, 2007).
(e) http://zacks.com (retrieved Sep. 13, 2007).
(f) First Call growth rates from http://finance.yahoo.com (retrieved Sep. 13, 2007).
(g) Average of (b) through (f).
(h) See Schedule WEA-3.
(i) Sum of dividend yield and (g).
(j) Sum of dividend yield and (h).
(k) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

GAS UTILITY PROXY GROUP

	(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Projections			Historical		Mid-Year					
			Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
Company	**EPS**	**DPS**	**Value**	**Value**	**Change**	**Factor**	**"b"**	**"r"**	**growth**	**Factor**	**Growth**
AGL Resources, Inc.	$3.10	$1.80	$22.50	$20.71	1.7%	1.0083	41.9%	13.9%	5.8%	0.54%	6.4%
Atmos Energy Corp.	$2.45	$1.35	$26.35	$20.16	5.5%	1.0268	44.9%	9.5%	4.3%	1.82%	6.1%
Laclede Group	$2.35	$1.60	$24.50	$18.85	5.4%	1.0262	31.9%	9.8%	3.1%	1.70%	4.8%
New Jersey Resources	$3.35	$1.84	$33.25	$22.50	8.1%	1.0390	45.1%	10.5%	4.7%	0.59%	5.3%
Nicor, Inc.	$2.90	$1.86	$23.05	$19.43	3.5%	1.0171	35.9%	12.8%	4.6%	0.04%	4.6%
Northwest Natural Gas	$3.20	$1.86	$26.35	$22.01	3.7%	1.0180	41.9%	12.4%	5.2%	0.65%	5.8%
Piedmont Natural Gas	$1.70	$1.16	$13.60	$11.83	2.8%	1.0139	31.8%	12.7%	4.0%	-1.34%	2.7%
South Jersey Industries	$2.85	$1.20	$17.95	$15.11	3.5%	1.0172	57.9%	16.2%	9.4%	2.16%	11.5%
Southern Union Co.	$2.35	$0.56	$25.60	$15.20	11.0%	1.0521	76.2%	9.7%	7.4%	0.91%	8.3%
Southwest Gas	$2.70	$0.90	$25.25	$21.58	3.2%	1.0157	66.7%	10.9%	7.2%	2.55%	9.8%
UGI Corp.	$2.45	$0.76	$17.45	$10.43	10.8%	1.0514	69.0%	14.8%	10.2%	0.61%	10.8%
WGL Holdings, Inc.	$2.30	$1.52	$22.70	$18.28	4.4%	1.0217	33.9%	10.4%	3.5%	0.24%	3.8%

(a) The Value Line Investment Survey (Sep. 14, 2007).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio)
(h) (f) + (g).

GAS UTILITY PROXY GROUP

MULTI-STAGE DCF MODEL

		Future Stock Price								Annual Cash Flows						Implied
	Recent	2010-12	Terminal	Proj.	Future	2007	2008	2010-12	Annual							Cost of
Company	**Price**	**DPS**	**"g"**	**D_1**	**Price**	**Div.**	**Div.**	**Div.**	**Change**	**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**End Yr 5**	**Equity**
AGL Resources, Inc.	$40.11	$1.80	6.4%	$1.91	$51.03	$ 1.64	$ 1.64	$ 1.80	$0.05	$ 0.41	$ 1.64	$ 1.69	$ 2.10	$ 1.80	$ 51.03	10.1%
Atmos Energy Corp.	$28.16	$1.35	6.1%	$1.43	$35.22	$ 1.28	$ 1.30	$ 1.35	$0.02	$ 0.32	$ 1.30	$ 1.32	$ 1.64	$ 1.35	$ 35.22	10.2%
Laclede Group	$32.64	$1.60	4.8%	$1.68	$39.05	$ 1.45	$ 1.49	$ 1.60	$0.04	$ 0.36	$ 1.49	$ 1.53	$ 1.89	$ 1.60	$ 39.05	9.1%
New Jersey Resources	$48.33	$1.84	5.3%	$1.94	$59.55	$ 1.52	$ 1.60	$ 1.84	$0.08	$ 0.38	$ 1.60	$ 1.68	$ 2.06	$ 1.84	$ 59.55	8.6%
Nicor, Inc.	$42.08	$1.86	4.6%	$1.95	$49.65	$ 1.86	$ 1.86	$ 1.86	$0.00	$ 0.47	$ 1.86	$ 1.86	$ 2.33	$ 1.86	$ 49.65	8.6%
Northwest Natural Gas	$46.07	$1.86	5.8%	$1.97	$58.16	$ 1.44	$ 1.52	$ 1.86	$0.11	$ 0.36	$ 1.52	$ 1.63	$ 1.99	$ 1.86	$ 58.16	9.2%
Piedmont Natural Gas	$26.46	$1.16	2.7%	$1.19	$29.34	$ 1.00	$ 1.04	$ 1.16	$0.04	$ 0.25	$ 1.04	$ 1.08	$ 1.33	$ 1.16	$ 29.34	6.7%
South Jersey Industries	$34.02	$1.20	11.5%	$1.34	$52.95	$ 0.98	$ 1.04	$ 1.20	$0.05	$ 0.25	$ 1.04	$ 1.09	$ 1.34	$ 1.20	$ 52.95	14.0%
Southern Union Co.	$30.00	$0.56	8.3%	$0.61	$41.88	$ 0.40	$ 0.44	$ 0.56	$0.04	$ 0.10	$ 0.44	$ 0.48	$ 0.58	$ 0.56	$ 41.88	9.7%
Southwest Gas	$29.11	$0.90	9.8%	$0.99	$42.31	$ 0.86	$ 0.86	$ 0.90	$0.01	$ 0.22	$ 0.86	$ 0.87	$ 1.09	$ 0.90	$ 42.31	12.1%
UGI Corp.	$25.74	$0.76	10.8%	$0.84	$38.77	$ 0.75	$ 0.76	$ 0.76	$0.00	$ 0.19	$ 0.76	$ 0.76	$ 0.95	$ 0.76	$ 38.77	13.0%
WGL Holdings, Inc.	$33.34	$1.52	3.8%	$1.58	$38.38	$ 1.36	$ 1.40	$ 1.52	$0.04	$ 0.34	$ 1.40	$ 1.44	$ 1.78	$ 1.52	$ 38.38	7.9%
Average																**10.2%**

Source: The Value Line Investment Survey (Sep. 14, 2007).

DISCOUNTED CASH FLOW MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Growth Rates							Cost of Equity Estimates	
		Dividend	Analyst Earnings Growth Projections							Projected	br+sv
	Company	Yield	IBES	V. Line	Reuters	Zack's	First Call	Average	br+sv	EPS Growth	Growth
1	3M Company	2.12%	11%	5.0%	11.1%	11.1%	11.1%	9.9%	16.1%	12.0%	18.2%
2	Abbott Labs.	2.46%	12%	9.5%	10.6%	10.6%	12.0%	10.9%	14.2%	13.4%	16.7%
3	Aflac Inc.	1.52%	15%	12.5%	14.2%	13.8%	14.5%	14.0%	13.1%	15.5%	14.6%
4	Anheuser-Busch	2.66%	9%	7.0%	9.0%	8.8%	8.6%	8.5%	26.8%	11.1%	29.4%
5	Automatic Data Proc.	1.99%	15%	9.5%	13.5%	13.3%	14.9%	13.2%	10.2%	15.2%	12.2%
6	Bard (C.R.)	0.71%	14%	14.0%	14.2%	14.0%	14.2%	14.1%	12.7%	14.8%	13.4%
7	Becton, Dickinson	1.27%	13%	11.5%	12.5%	13.0%	12.7%	12.5%	13.3%	13.8%	14.5%
8	Coca-Cola	2.49%	9%	9.0%	9.2%	8.8%	9.2%	9.0%	9.4%	11.5%	11.9%
9	Colgate-Palmolive	2.18%	11%	11.0%	10.6%	10.8%	10.7%	10.8%	20.9%	13.0%	23.1%
10	Ecolab Inc.	1.10%	14%	13.0%	14.8%	14.5%	14.4%	14.1%	18.6%	15.2%	19.7%
11	Fortune Brands	2.05%	10%	6.0%	9.7%	10.8%	9.7%	9.2%	10.5%	11.3%	12.6%
12	Gannett Co.	3.34%	7%	3.5%	5.6%	6.6%	5.7%	5.7%	7.7%	9.0%	11.0%
13	Gen'l Mills	2.71%	8%	7.0%	8.5%	8.5%	8.1%	8.0%	6.6%	10.7%	9.3%
14	Genuine Parts	3.00%	9%	9.5%	9.3%	8.9%	9.3%	9.2%	9.5%	12.2%	12.5%
15	Harte-Hanks	1.18%	11%	7.5%	10.5%	10.2%	10.7%	10.0%	12.2%	11.2%	13.3%
16	Heinz (H.J.)	3.34%	7%	8.0%	7.8%	7.6%	7.4%	7.6%	12.3%	10.9%	15.6%
17	Hershey Co.	2.60%	9%	7.0%	8.9%	9.0%	9.1%	8.6%	14.9%	11.2%	17.5%
18	Hormel Foods	1.68%	10%	10.5%	9.5%	8.8%	9.5%	9.7%	12.8%	11.3%	14.5%
19	Johnson & Johnson	2.69%	8%	8.0%	9.1%	9.2%	7.9%	8.4%	10.9%	11.1%	13.6%
20	Kimberly-Clark	3.09%	7%	5.5%	7.6%	8.3%	7.5%	7.2%	10.3%	10.3%	13.4%
21	Kraft Foods	3.24%	7%	5.5%	7.5%	7.1%	7.4%	6.9%	5.2%	10.1%	8.4%
22	Lilly (Eli)	2.96%	8%	7.0%	8.0%	8.2%	7.6%	7.8%	11.7%	10.7%	14.7%
23	Lockheed Martin	1.42%	11%	15.0%	10.1%	9.5%	11.5%	11.4%	15.4%	12.8%	16.9%
24	Medtronic, Inc.	0.93%	13%	12.5%	14.2%	14.0%	13.8%	13.5%	14.2%	14.4%	15.2%
25	Meredith Corp.	1.33%	12%	11.5%	11.8%	11.8%	11.8%	11.8%	11.3%	13.1%	12.6%
26	PepsiCo, Inc.	2.19%	11%	10.5%	11.4%	11.2%	11.0%	11.0%	10.4%	13.2%	12.6%
27	Pfizer, Inc.	4.71%	5%	2.0%	7.7%	7.4%	4.2%	5.2%	2.0%	10.0%	6.7%
28	Procter & Gamble	2.12%	11%	10.5%	11.6%	11.6%	11.7%	11.3%	6.1%	13.4%	8.2%

DISCOUNTED CASH FLOW MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Growth Rates							Cost of Equity Estimates	
		Dividend	Analyst Earnings Growth Projections							Projected	br+sv
	Company	Yield	IBES	V. Line	Reuters	Zack's	First Call	Average	br+sv	EPS Growth	Growth
29	Sara Lee Corp.	2.48%	8%	-1.0%	7.1%	7.1%	6.7%	5.6%	10.8%	8.1%	13.3%
30	Sysco Corp.	2.30%	13%	11.5%	13.3%	12.3%	13.4%	12.7%	13.4%	15.0%	15.7%
31	United Parcel Serv.	2.24%	12%	9.0%	11.4%	11.2%	11.6%	11.1%	12.9%	13.3%	15.1%
32	UnitedHealth Group	0.06%	15%	15.0%	15.2%	15.1%	15.5%	15.2%	12.3%	15.2%	12.4%
33	Wal-Mart Stores	2.06%	12%	10.0%	12.4%	11.8%	12.2%	11.7%	11.5%	13.8%	13.5%
34	Walgreen Co.	0.84%	15%	15.0%	15.3%	15.3%	15.3%	15.2%	13.9%	16.0%	14.8%
35	Washington Federal	3.21%	8%	10.5%	7.4%	7.0%	7.9%	8.2%	9.8%	11.4%	13.0%
36	Washington Post	1.04%	9%	5.5%	9.4%	16.9%	7.7%	9.7%	8.2%	10.7%	9.2%
37	Wells Fargo	3.48%	11%	10.5%	11.2%	11.3%	10.9%	11.0%	11.2%	14.4%	14.7%
38	Wrigley (Wm.) Jr.	1.94%	11%	9.0%	10.4%	10.1%	10.5%	10.2%	11.0%	12.1%	12.9%
	Average (k)									**12.4%**	**13.2%**

(a) www.valueline.com (retrieved Sep. 14, 2007).
(b) I/B/E/S International growth rates from Standard & Poor's Earnings Guide, (Aug. 2007).
(c) www.valueline.com (retrieved Sep. 14, 2007).
(d) http://stocks.us.reuters.com (retrieved Sep. 14, 2007).
(e) http://zacks.com (retrieved Sep. 16, 2007).
(f) First Call growth rates from http://finance.yahoo.com (retrieved Sep. 16, 2007).

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
1	3M Company	$5.80	$2.28	$21.70	$13.56	9.9%	1.0470	60.7%	28.0%	17.0%	-0.89%	16.1%
2	Abbott Labs.	$4.20	$1.60	$17.60	$9.14	14.0%	1.0654	61.9%	25.4%	15.7%	-1.50%	14.2%
3	Aflac Inc.	$5.20	$1.32	$26.90	$16.93	9.7%	1.0463	74.6%	20.2%	15.1%	-1.97%	13.1%
4	Anheuser-Busch	$3.90	$1.28	$7.75	$5.11	8.7%	1.0416	67.2%	52.4%	35.2%	-8.43%	26.8%
5	Automatic Data Proc.	$3.00	$1.15	$17.20	$10.71	9.9%	1.0473	61.7%	18.3%	11.3%	-1.05%	10.2%
6	Bard (C.R.)	$6.35	$0.86	$32.75	$16.46	14.8%	1.0687	86.5%	20.7%	17.9%	-5.21%	12.7%
7	Becton, Dickinson	$5.60	$1.60	$29.75	$15.63	13.7%	1.0643	71.4%	20.0%	14.3%	-1.04%	13.3%
8	Coca-Cola	$3.70	$1.84	$12.10	$7.30	10.6%	1.0505	50.3%	32.1%	16.1%	-6.74%	9.4%
9	Colgate-Palmolive	$5.00	$2.16	$10.40	$2.32	35.0%	1.1489	56.8%	55.2%	31.4%	-10.45%	20.9%
10	Ecolab Inc.	$2.65	$0.65	$10.20	$6.69	8.8%	1.0422	75.5%	27.1%	20.4%	-1.87%	18.6%
11	Fortune Brands	$7.15	$1.76	$54.05	$31.08	11.7%	1.0553	75.4%	14.0%	10.5%	0.01%	10.5%
12	Gannett Co.	$6.00	$1.84	$53.80	$35.71	8.5%	1.0410	69.3%	11.6%	8.0%	-0.38%	7.7%
13	Gen'l Mills	$4.30	$2.00	$19.05	$16.21	3.3%	1.0161	53.5%	22.9%	12.3%	-5.66%	6.6%
14	Genuine Parts	$4.25	$1.90	$23.50	$14.95	9.5%	1.0452	55.3%	18.9%	10.5%	-0.91%	9.5%
15	Harte-Hanks	$2.00	$0.40	$12.50	$6.58	13.7%	1.0641	80.0%	17.0%	13.6%	-1.47%	12.2%
16	Heinz (H.J.)	$3.60	$1.88	$10.00	$5.72	11.8%	1.0558	47.8%	38.0%	18.2%	-5.87%	12.3%
17	Hershey Co.	$3.30	$1.50	$3.90	$2.97	5.6%	1.0272	54.5%	86.9%	47.4%	-32.51%	14.9%
18	Hormel Foods	$3.30	$0.80	$20.60	$13.13	9.4%	1.0450	75.8%	16.7%	12.7%	0.15%	12.8%
19	Johnson & Johnson	$5.50	$2.04	$25.95	$13.59	13.8%	1.0646	62.9%	22.6%	14.2%	-3.27%	10.9%
20	Kimberly-Clark	$5.20	$2.76	$17.90	$13.38	6.0%	1.0291	46.9%	29.9%	14.0%	-3.73%	10.3%
21	Kraft Foods	$2.60	$1.00	$22.65	$17.45	5.4%	1.0261	61.5%	11.8%	7.2%	-2.05%	5.2%
22	Lilly (Eli)	$4.50	$2.20	$17.30	$9.70	12.3%	1.0578	51.1%	27.5%	14.1%	-2.35%	11.7%
23	Lockheed Martin	$10.00	$2.25	$39.30	$16.35	19.2%	1.0875	77.5%	27.7%	21.4%	-6.00%	15.4%
24	Medtronic, Inc.	$4.35	$0.83	$17.75	$9.60	13.1%	1.0614	80.9%	26.0%	21.0%	-6.82%	14.2%
25	Meredith Corp.	$4.80	$0.90	$29.45	$14.49	15.2%	1.0708	81.3%	17.5%	14.2%	-2.91%	11.3%
26	PepsiCo, Inc.	$4.85	$1.95	$15.65	$9.36	10.8%	1.0514	59.8%	32.6%	19.5%	-9.06%	10.4%
27	Pfizer, Inc.	$2.30	$1.36	$12.25	$9.98	4.2%	1.0205	40.9%	19.2%	7.8%	-5.82%	2.0%
28	Procter & Gamble	$4.60	$1.90	$33.45	$19.33	11.6%	1.0548	58.7%	14.5%	8.5%	-2.45%	6.1%

NON-UTILITY PROXY GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			**Historical**		**Mid-Year**					
				Net Book	**Net Book**	**Annual**	**Adjustment**		**Adjusted**	**"b x r"**	**"sv"**	**Sustainable**
	Company	**EPS**	**DPS**	**Value**	**Value**	**Change**	**Factor**	**"b"**	**"r"**	**growth**	**Factor**	**Growth**
29	Sara Lee Corp.	$1.20	$0.45	$3.80	$3.22	3.4%	1.0166	62.5%	32.1%	20.1%	-9.22%	10.8%
30	Sysco Corp.	$2.70	$1.10	$7.75	$4.93	9.5%	1.0452	59.3%	36.4%	21.6%	-8.22%	13.4%
31	United Parcel Serv.	$5.75	$2.00	$27.25	$14.47	13.5%	1.0632	65.2%	22.4%	14.6%	-1.74%	12.9%
32	UnitedHealth Group	$5.70	$0.05	$25.10	$15.47	10.2%	1.0484	99.1%	23.8%	23.6%	-11.26%	12.3%
33	Wal-Mart Stores	$4.75	$1.15	$24.40	$14.91	10.4%	1.0492	75.8%	20.4%	15.5%	-4.03%	11.5%
34	Walgreen Co.	$3.50	$0.48	$20.45	$10.04	15.3%	1.0710	86.3%	18.3%	15.8%	-1.88%	13.9%
35	Washington Federal	$2.90	$1.00	$19.40	$14.46	6.1%	1.0294	65.5%	15.4%	10.1%	-0.25%	9.8%
36	Washington Post	$47.45	$9.70	$483.90	$330.20	7.9%	1.0382	79.6%	10.2%	8.1%	0.07%	8.2%
37	Wells Fargo	$4.10	$1.44	$23.75	$13.58	11.8%	1.0558	64.9%	18.2%	11.8%	-0.63%	11.2%
38	Wrigley (Wm.) Jr.	$3.20	$1.38	$14.95	$8.65	11.6%	1.0547	56.9%	22.6%	12.8%	-1.88%	11.0%

(a) www.valueline.com (retrieved Sep. 17, 2007).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

CAPITAL ASSET PRICING MODEL

FORWARD-LOOKING RISK PREMIUM

Market Rate of Return		
Dividend Yield (a)	2.2%	
Growth Rate (b)	10.5%	
Market Return (c)		12.7%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		5.0%
Market Risk Premium (e)		7.7%
Utility Proxy Group Beta (f)		0.86
Utility Proxy Group Risk Premium (g)		6.6%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		5.0%
Implied Cost of Equity (h)		**11.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Aug. 28, 2007).
(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Standard & Poor's Earnings Guide (Aug. 2007) and www.valueline.com (Retreived Aug. 28, 2007).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for Aug. 2007 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Sep. 14, 2007)
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

HISTORICAL RISK PREMIUM

Market Risk Premium	
Long-Horizon Equity Risk Premium (a)	7.1%
Utility Proxy Group Beta (b)	0.86
Utility Proxy Group Risk Premium (c)	6.1%
Plus: Risk-free Rate (d)	
Long-term Treasury Bond Yield	5.0%
Implied Cost of Equity (e)	**11.1%**

(a) Arithmetic mean risk premium on Large Company Stocks from 1926-2006 reported by Morningstar, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2007 Yearbook* , at Appendix C, Table C-1, p. 262.
(b) The Value Line Investment Survey (Sep. 14, 2007)
(c) (a) x (b).
(d) Average yield on 20-year Treasury bonds for Aug. 2007 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) + (d).

REALIZED RETURNS

	Moody's Gas Distribution Stocks (a)			Moody's Single-A Utility Bonds (b)
	DEC PRICE	DIV	Annual Realized Return	Income Return
1952	$20.57			3.22%
1953	$21.23	$1.09	8.51%	3.38%
1954	$26.47	$1.19	30.29%	3.11%
1955	$28.10	$1.32	11.14%	3.35%
1956	$28.23	$1.43	5.55%	3.91%
1957	$25.78	$1.49	-3.40%	4.36%
1958	$38.71	$1.53	56.09%	4.49%
1959	$39.59	$1.63	6.48%	4.96%
1960	$48.21	$1.79	26.29%	4.65%
1961	$64.96	$1.91	38.71%	4.65%
1962	$59.73	$2.01	-4.96%	4.44%
1963	$64.62	$2.13	11.75%	4.46%
1964	$68.24	$2.27	9.11%	4.54%
1965	$64.31	$2.40	-2.24%	4.83%
1966	$53.50	$2.75	-12.53%	5.67%
1967	$50.49	$2.67	-0.64%	6.67%
1968	$53.80	$2.79	12.08%	6.87%
1969	$43.88	$2.88	-13.09%	8.59%
1970	$52.33	$2.97	26.03%	8.48%
1971	$47.86	$3.06	-2.69%	7.90%
1972	$53.54	$3.10	18.35%	7.48%
1973	$43.43	$3.21	-12.89%	8.24%
1974	$29.71	$3.31	-23.97%	10.27%
1975	$38.29	$3.43	40.42%	10.11%
1976	$51.80	$3.65	44.82%	8.62%
1977	$50.88	$3.85	5.66%	8.64%
1978	$45.97	$4.07	-1.65%	9.70%
1979	$53.50	$4.33	25.80%	11.79%
1980	$56.61	$4.59	14.39%	14.63%
1981	$53.50	$4.95	3.25%	16.29%
1982	$50.62	$5.28	4.49%	14.43%
1983	$55.79	$5.45	20.98%	13.52%
1984	$69.70	$5.71	35.17%	13.11%
1985	$76.58	$6.06	18.57%	10.97%
1986	$90.89	$5.68	26.10%	9.12%
1987	$77.25	$5.86	-8.56%	10.98%
1988	$86.76	$6.15	20.27%	10.06%
1989	$117.05	$6.45	42.35%	9.44%
1990	$108.86	$6.70	-1.27%	9.73%
1991	$124.32	$6.94	20.58%	8.88%
1992	$138.79	$7.08	17.33%	8.43%
1993	$154.06	$7.23	16.21%	7.34%
1994	$126.96	$7.36	-12.81%	8.76%
1995	$155.94	$7.48	28.72%	7.23%
1996	$166.64	$7.76	11.84%	7.59%
1997	$191.04	$7.99	19.44%	7.16%
1998	$177.24	$8.12	-2.97%	6.91%
1999	$166.84	$8.18	-1.25%	8.14%
2000	$200.68	$8.22	25.21%	7.84%
2001	$203.07	$8.22	5.29%	7.83%
AVERAGE 1953-2001			**12.29%**	**8.01%**

Realized Rates of Return	
Moody's Gas Distribution	12.29%
Single-A Public Utility Bonds	8.01%
Equity Risk Premium	4.28%
Aug. 2007 Single-A Utility Bond Yield (c)	6.24%
Implied Cost of Equity	**10.52%**

(a) Mergent *Public Utility Manual* (2002); Mergent *Public Utility News Reports* (Jan. 15, 2002).
(b) Average yield for December from Mergent *Public Utility Manual* (2003).
(c) Moody's *Credit Perspectives* (Sep. 10, 2007).

EXPECTED EARNINGS APPROACH

GAS UTILITY PROXY GROUP

Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
AGL Resources, Inc.	14.0%	1.0083	14.1%
Atmos Energy Corp.	9.0%	1.0268	9.2%
Laclede Group	10.0%	1.0262	10.3%
New Jersey Resources	10.5%	1.0390	10.9%
Nicor, Inc.	13.0%	1.0171	13.2%
Northwest Natural Gas	11.5%	1.0180	11.7%
Piedmont Natural Gas	12.5%	1.0139	12.7%
South Jersey Industries	15.5%	1.0172	15.8%
Southern Union Co.	10.5%	1.0521	11.0%
Southwest Gas	10.5%	1.0157	10.7%
UGI Corp.	14.0%	1.0514	14.7%
WGL Holdings, Inc.	10.5%	1.0217	10.7%
Average			**12.1%**

(a) 3-5 year projections from The Value Line Investment Survey (Sep. 14, 2007)
(b) See Schedule WEA-3. An adjustment is necessary to reflect Value Line's use of year-end capital balances
(c) (a) x (b).

APPENDIX A

QUALIFICATIONS OF WILLIAM E. AVERA

Q. What is the purpose of this exhibit?

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

Q. What are your qualifications?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the United States Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission, as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 30 states.

In 1995, I was appointed by the PUCT, with the approval of the Governor, to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered

Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I also have served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners (NARUC) Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I also have served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance, The University of Texas at Austin (Sep. 1979 to May 1981) Assistant Professor of Finance, (Sep. 1975 to May 1977)	Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.
Assistant Professor of Business, University of North Carolina at Chapel Hill (Sep. 1972 to Jul. 1975)	Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance, University of North Carolina at Chapel Hill (Jan. 1969 to Aug. 1972)	Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics. Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*
B.A., Economics, Emory University, Atlanta, Georgia (Sep. 1961 to Jun. 1965)	Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

<u>Business and Government-Sponsored Programs</u>: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in 240 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

<u>Federal Agencies:</u> Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

<u>State Regulatory Agencies:</u> Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 40 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (80 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

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"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

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"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

Exhibit 400
Christie

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF KEVIN J. CHRISTIE
REPRESENTING THE AVISTA CORPORATION

Gas Supply, Storage and Pro Formed Capital Projects

I. INTRODUCTION

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

A. My name is Kevin Christie and I am employed as Director of Gas Supply of Avista Utilities (Avista or Company), at 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. I graduated from Washington State University with a Bachelors degree in Business Administration with an accounting emphasis. I have also attended the University of Idaho Utility Executive Course.

I joined the company in 2005 as the Manager of Natural Gas Planning. In 2007, I was appointed the Director of Gas Supply. Prior to joining Avista, I was employed by Gas Transmission Northwest (GTN). I was employed by GTN from 2001 to 2005 and was the Director of Pipeline Marketing and Development from 2003 to 2005 and the Director of Pricing and Business Analysis from 2001 to 2003. From 2000 to 2001, I was employed by PG&E Corporation (PG&E) as the Manager of Finance and Assistant to the SVP, Treasurer and CFO. Before joining PG&E, I was employed by Pacific Gas Transmission Company (PGT) from 1994 to 2000. While at PGT, I held several positions including Manager, Pricing and Business Analysis, Senior Business Analyst, Senior Pricing Planner, Director of Regulatory Affairs, Project Manager – Rates and Regulatory Affairs, Senior Regulatory Analyst, Regulatory Analyst, and Revenue Accountant. From 1990 to 1994, I was employed by Chevron USA as a Lease Revenue Accountant.

Q. Mr. Christie, what is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to identify and explain natural gas storage opportunities for Avista's firm sales customers in Oregon. In addition, I will discuss five major capital projects that will be completed by Avista in the Oregon region and that have been pro formed into this filing.

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 401 which was prepared under my direction.

II. Natural Gas Storage

Q. Please describe the benefits of storage to Avista's Oregon customers?

A. Access to storage provides several benefits to customers. It provides an opportunity to capture the seasonal price spread between non-winter and winter seasons. Storage withdrawal capability provides for additional reliability. Storage also provides for mitigation of price spikes during peak pricing events.

Q. What is the value of the seasonal price spread?

A. The seasonal price spread in its simplest terms is the difference in the price per Dekatherm (Dth) between what one could purchase the gas for in the non-winter months versus what those same volumes would cost if purchased in the winter season. Using the last few months as an example, the difference between the injection prices for 2007 from the Oregon PGA filing dated 8/31/07 and average forward winter prices for the 2007 – 2008 winter period (Nov.-March) on 9/21/07 is $2.57 per Dth, as shown in the table on the following page.

Differential Calculation	
JP Oregon Storage WACOG per Avista PGA Filing 8/31/2007	$ 5.0381
Sumas Nov '07 - Mar '08 Average Price on 9/21/07	$ 7.6100
Summer/Winter Differential	$ 2.5719

Further, Exhibit No. 401, page 1 shows a forward look at future pricing differentials between winter and non-winter months at Sumas. Sumas is the market point that is the likely purchasing point for natural gas injections into Northwest area storage. This exhibit indicates, when looking at the next three years, a current future average differential of $1.33 per Dth and a current maximum differential of $1.92 per Dth (when comparing the lowest priced month to the highest priced month in the forward market for a given year).

Q. Is there always a summer-to-winter price spread that is beneficial to customers?

A. Generally, there is a positive spread between non-winter and winter months, but there have been times in the past when market dynamics have been such that non-winter-to-winter prices were flat or even upside-down, so storage is not without some risk. A review of data over the last 10 years, comparing the lowest injection prices both by day and month to the highest withdrawal pricing both by day and month, shows the entire period having a positive price spread.

Q. You mentioned improved reliability of supply, please explain.

A. The Company relies on monthly and longer-term seasonal, annual and three-year contracts for supply to satisfy its projected average daily demand. For daily swings in load, above and below average, the Company relies on a combination of storage and daily purchases and sales. In today's market, virtually all physical short-term purchases are done at market hubs like Sumas/Huntingdon. While these purchases are generally reliable, there is a risk of delivery failure. There are a number of reasons why delivery risk can be problematic. First, using the Sumas/Huntingdon Hub as an example, gas may change hands (trade) 3 or 4 times between parties. The failure of one party in the chain relying on interruptible transportation or a less than secure supply source can result in supply loss on any given day. A second reason is that it just takes one scheduling error in the supply chain to result in a supply loss. And third, actual physical problems like well freeze-offs or pipeline force majeure situations along the transportation path can also result in supply loss. Access to storage provides the Company with more control and therefore more reliability of supply during these events.

Q. Please explain what you mean by mitigation of peak demand price spikes.

A. As with most local distribution companies in the Northwest, Avista's demand is very temperature-sensitive. The result is that Avista is a "winter peaking" utility. During severe cold weather events in its service territory or cold events in large market centers on the eastern seaboard, natural gas prices may increase dramatically. To the extent that the Company can rely on storage withdrawals, the purchase of potentially higher priced spot gas may be avoided during these events. This benefit is in addition to the typical non-winter-to-winter price spread discussed above.

Q. Please describe historical storage opportunities for Oregon customers.

A. When Avista purchased the Oregon property, which was operated by CP National, it assumed a contract for Storage Gas Service under schedule SGS-2F provided by Northwest Pipeline from their 1/3 share of the Jackson Prairie Storage facility. This contract had a daily deliverability of 2,654 Dth with a seasonal capacity of 95,565 Dth (as amended to today's volumes). Also assumed in the CP National purchase was a contract for LNG storage service from Northwest Pipeline to which the Company was committed for a number of years. Termination notice of this LNG storage contract was given by Avista approximately a year ago. The service terminated in April of 2007 because there were more economic alternatives available for Oregon customers.

Q. How much of Avista's average demand can be served by the SGS-2F contract?

A. The capacity from the SGS-2F contact can only serve approximately 1% of average annual demand.

Q. How has Avista been involved with Jackson Prairie?

A. Avista was one of the three original developers of the storage facility at Jackson Prairie. Although there have been corporate changes because of mergers, acquisitions and name changes, Avista, Puget Sound Energy and Northwest Pipeline each hold a 1/3 share of this underground gas storage facility. Development began in the 1960's and the project first went into service in 1972. A number of expansions have been developed and Avista currently holds a total of 8,308,694 Dth of seasonal capacity and 294,667 Dth of daily withdrawal capability.

Q. Is all of this storage space dedicated to serve the utility's firm customers?

A. Under Federal Energy Regulatory Commission (FERC) regulations, Avista is not authorized to provide storage service for parties other than its core customers. However, based on Integrated Resource Plans in effect at the time, the development of the recent expansions gave the Company greater storage capacity than it needed to serve customers at the time, so the two most recent expansions were temporarily assigned to Avista Energy. Avista Energy provided the capital necessary to develop the expansions and had the right to use that portion of the storage facility. Because Avista Energy invested the capital for these expansions, they were not included in customer's rates.

Q. How much of the storage facility is included in customers rates?

A. All of the capacity and deliverability that existed prior to the two most recent expansion projects which were paid for by Avista Energy is included in rate base and dedicated to serve the Company's customers in Washington and Idaho. This amounts to daily withdrawal capability of 190,667 Dth and seasonal capacity of 5,234,666 Dth.

Q. Please explain the expansion projects in which Avista Energy participated.

A. The facility was expanded (FERC Certificate in CP98-250-000) in 1999. The expansion resulted in Avista's share being increased by 1,109,334 Dth seasonal working gas capacity and 104,000 Dth/d withdrawal capability. In 2002 a long term capacity expansion (FERC Certificate in CP02-384-000) was initiated that would result in an additional 2.1 BCF of seasonal working gas capacity for Avista. This project was phased in over several years. Avista's portion will be completed in mid-2008. Both of these expansion projects were temporarily assigned to Avista Energy, which agreed to pay for the expansion costs. The current net book value of these projects held by Avista Energy is approximately $12,600,000.

Q. What is the current status of the storage held by Avista Energy?

A. The storage held by Avista Energy was assigned to Shell Trading/Coral until April 2011. At that time, Avista Corp has rights to purchase the storage capacity from Avista

Energy for its core customers. Avista Energy's participation in the 2002 to 2008 capacity expansion project stopped on June 30, 2007 and Avista Corp. is completing the project on behalf of customers beginning July 1, 2007.

Q. Is Avista Corp. participating in any other expansion projects?

A. Yes. In 2006 Avista and its partners started another expansion project at Jackson Prairie (FERC Certificate in CP06-412) for deliverability for a project that will be in service in the Fall of 2008 and will result in Avista's daily deliverability increasing by 104,000 Dth.

Q. Are any of the expansion projects you describe above available to serve Oregon customers?

A. Yes. Avista proposes to assign all of the remaining 2002/2008 expansion capacity to Oregon customers (Phase 1). This will provide for approximately 253,000 Dth of working gas capacity. Additionally, when the 2008 Deliverability expansion is completed, approximately 25% of the 104,000 Dth/d or 26,000 Dth/d of delivery capacity will be assigned to Oregon (Phase II). Also, it is anticipated that in 2011, when the Avista Energy capacity and deliverability is purchased from Avista Energy (Phase III), the expansion capacity will be reapportioned so that approximately 25% of all of the expansion projects described above will be assigned to Oregon Customers.

Q. Why is the Company assigning 25% of this project to Oregon?

A. The Company has firm demand in Oregon, Idaho and Washington. The demand is split between Washington/Idaho and Oregon on a 75%/25% basis. This demand allocation was determined by using the estimated Oregon average load of approximately 9.360

million Dth in comparison to the estimated Company total average load of approximately 36.833 million Dth detailed in the Company's 2007/2008 Procurement Plan. The Company proposes to allocate this new capacity on that ratio.

Q. What other storage is available to Oregon customers?

A. Effective in April of 2007, Avista contracted with Northwest Natural for service from its Mist facility for three years. This contract is for a daily withdrawal capability of 15,000 Dth and a seasonal capacity of 300,000 Dth.

Q. It appears that the Mist contract will overlap the availability of Jackson Prairie for at least two years. Is that correct?

A. Yes, there will be an overlap, but the addition of the Mist Storage was economically viable based on an analysis of savings from the seasonal price spread for the duration of the contract. Further, this storage contract provides for a "bridge" between 2007 and 2011 when the Avista Energy expansion capacity is available from Shell/Coral. Continuation of the Mist contract will be assessed based on economics at the time of contract expiration. With the original SGS-2F contract and the Mist contract, Avista is now able to serve approximately 4% of average annual load through storage. In 2011, the company may determine, assuming availability, that it is economically viable to keep both Mist and Jackson Prairie storage for Oregon customers.

Q. Is there any pipeline transportation capacity available to provide delivery of these storage volumes?

A. Yes, although no new capacity is available, existing transportation contracts from Sumas can be used to redeliver storage volumes. The Company will avoid a portion of winter purchases and utilize storage as a substitute for this supply. Therefore, the same transportation contracts that are utilized now for physical supply purchases will be used for the delivery of storage gas.

Q. Can you summarize the storage availability for Oregon customers?

A. Yes, Exhibit No. 501, page 2 illustrates the various components of storage that I have identified in this testimony. This exhibit shows, by expansion project, the estimated timing, capacity and deliverability of Jackson Prairie storage opportunities for Avista's Oregon customers.

Q. What is the estimated cost of the storage you have described?

A. Exhibit No. 501, page 3 shows the allocation of storage volumes and estimated project costs between Oregon, and Washington and Idaho customers. This exhibit apportions 25% of the cost to Oregon as previously discussed.

Q. Is the Company requesting specific rate relief or accounting treatment at this time to cover the cost of the Jackson Prairie storage expansion project?

A. No. The Company is not requesting rate relief at this time. Phase I and II of the project will be completed in the Fall of 2008. At that time, the benefits associated with this additional Jackson Prairie capacity will begin accruing to customers via the PGA mechanism, and the Company would request to begin recovering the costs associated with the expansion.

Q. How does the Company propose to recover the costs associated with this storage?

A. The Company will file a separate tariff effective November 1, 2008, coincident with the in-service date of the expansion, to begin recovering the revenue requirement associated with the Jackson Prairie capacity and delivery expansion projects. At that time, Avista will update the revenue requirement based on actual costs.

Q. What is the estimated revenue requirement necessary to recover these costs and what would be the estimated effect on Oregon customers' rates?

A. Using current estimated project costs of approximately $16 million (for Phase I and II), the estimated annual revenue requirement associated with the proposed Oregon allocation is approximately $613,000, which represents an increase of approximately 0.48% over pro forma revenues. The increase in annual revenue requirement to reflect actual project costs upon completion of Phase I and II on November 1, 2008 will be in place until further adjusted in 2011, when the Avista Energy capacity and deliverability is purchased from Avista Energy (Phase III).

Q. Has the Company discussed the proposed allocation of this new Jackson Prairie capacity, and associated costs, with the PUC Staff?

A. Yes. The Company has had discussions with the Commission Staff and they have indicated support for the Company's proposal as described above.

Q. How much of Avista's annual average Oregon demand will be served by storage after 2011?

A. Assuming that the Mist contract is not renewed, after the recall of Jackson Prairie storage from Shell Trading/Coral in 2011, Avista will be able to satisfy approximately 9% of average annual Oregon demand through storage.

III. Pro Formed Capital Projects

Q. Please explain the conversion of the Glendale distribution system from propane to natural gas.

A. The Glendale Propane System was initiated as a temporary system by CP National in 1966 with the intention of later converting the system to natural gas; however, the conversion did not occur. Avista acquired the system in 1991 when the Company purchased CP National's Oregon natural gas operating properties. The system provided firm propane distribution service to 128 residential and 30 commercial customers in Glendale. The community of Glendale, Oregon has a population of approximately 860 people and is located 21 miles south of Roseburg and approximately 20 miles north of Grants Pass, Oregon.

In 2002, much of the piping, valves and fittings on the propane supply tank were rebuilt. This project improved the safety and reliability of the system. Continuing to operate a propane system would have obligated Avista to continue to update and maintain propane training programs, operating and maintenance plans, operator qualification plans, and to stay current with new propane regulations.

Avista began construction of a 3.8 mile underground natural gas distribution line into Glendale, Oregon, in mid-June 2007 with construction along Azalea Glen Road and completed the line by the end of September 2007. The Company has engaged third-party contractors to assist in converting propane orifices on customer appliances such as furnaces, water heaters, stoves, dryers, and fireplaces so that they will operate on natural gas. All customer conversions were completed by early October of 2007.

Q. Please describe the costs of the Glendale conversion that are included in

this filing.

A. During 2007, Avista, the PUC Staff, the Citizens Utilities Board, and the Northwest Industrial Gas Users agreed in a Stipulation provided in Advice No. 07-02-G that the Glendale conversion project was in the public interest and stated that they supported the inclusion of the unamortized investment into rate base in the Company's next general rate filing. The Company agreed to offset the investment with the full amount of the Oregon Business Energy Tax Credit (BETC).

The project is estimated to cost $1.479 million and was completed in September 2007. This cost, net of the BETC of approximately $517,000, has been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits.

Q. Please describe the Company's East Medford Reinforcement Project and the costs that are included in this filing.

A. The East Medford Reinforcement Project will provide strategic high pressure pipeline encirclement of the Greater Medford Area for long-term gas supply to the eastern portions of the city. The project will allow for additional gas delivery from either TransCanada at the Company's Phoenix Road Gate Station or Northwest Pipeline at Grants Pass. It provides reinforcement of the system in anticipation of future load growth in Medford. One could liken it to a high pressure "beltway" around the east side of Medford, thereby providing pressure support to this entire segment of Avista's distribution system.

This project will be completed over a three-year period. Phase I will provide reinforcement of the existing distribution system by extending high pressure piping and installing a regulator station. The high pressure system will be further extended during subsequent phases to complete the looping of the system. Phase I capital costs total approximately $3.15 million, will be completed by July 2008, and such costs have been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits. Phase II will extend high pressure piping and reinforce the distribution system north of the existing Phoenix Rd. Gate Station. Phase III will complete the looping of the high pressure system on the east side of Medford by connecting Phase I and Phase II reinforcements. Each of the prospective phases provides an increased level of benefit to customers by reinforcement of the local distribution system. Phase II and Phase III capital costs are currently estimated at approximately $5.0 million and $6.0 million, respectively, and will be completed in October 2008 and October 2009, respectively. Neither Phase II nor III costs have been included in this filing.

Q. Please describe the Company's Integrity Management Pipe Replacement Project and the costs that are included in this filing.

A. The Integrity Management Pipe Replacement project is being completed in response to the integrity management regulation as detailed in 49 CFR 192, Subpart O – Pipeline Integrity Management. The regulation requires pipeline operators to evaluate covered segments and mitigate risk to the public by assessing the integrity of pipeline segments by direct assessment or lowering the operating stress of the pipeline which will reduce the consequences of an unforeseen event. This capital project addresses the replacement of 11 pipe sections that were identified as High Consequence Areas (HCA's) and required mitigation within the integrity management program (IMP). The capital cost is approximately $3.23 million, will be completed December 2007, and such costs have been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits.

Q. Please describe the Company's Roseburg Reinforcement Project and the costs that are included in this filing.

A. The Roseburg Reinforcement Project improves the delivery pressure and capacity of gas supplies on the east side of Roseburg by extending a high pressure gas supply. The existing system is marginally capable of meeting customer load on a design day. The only gas supplies in the Roseburg area are received on the west side of Roseburg. Due to growth and increase in customer demand, especially on the east side of Roseburg, the system must be reinforced to meet customer demand during cold weather. The project will install a new distribution source by extending piping and installing a regulator station. Phase I includes extension of piping from a pressure-limited source that will subsequently be upgraded during Phase II.

This project will be completed over a two-year period. Phase I capital costs total approximately $1.68 million, will be completed by March 2008, and such costs have been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits.

Phase II includes additional reinforcement of the system by increasing the delivery pressure and capacity of the Phase I reinforcement by extending the main to a higher pressure source. Phase II capital costs are currently estimated at approximately $1.7 million and will be completed in October 2008. Phase II has not been included in this filing.

Q. Please describe the Company's Merlin Gate Station Project and the costs that are included in this filing.

A. The Merlin Gate Station Project in Grants Pass increases the gas delivery capacity from Williams Pipeline into the Grants Pass area. The existing facilities at the Merlin Gate Station are not capable of receiving the required gas capacity during high system demand. Upgrade of the facilities is necessary to meet existing and future load. The project will include new metering, line heater, and regulation.

The project is estimated to cost approximately $473,000, will be completed in March 2008, and such costs have been pro formed into this filing. Ms. Andrews incorporates these costs in her testimony and exhibits.

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

A. Yes it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

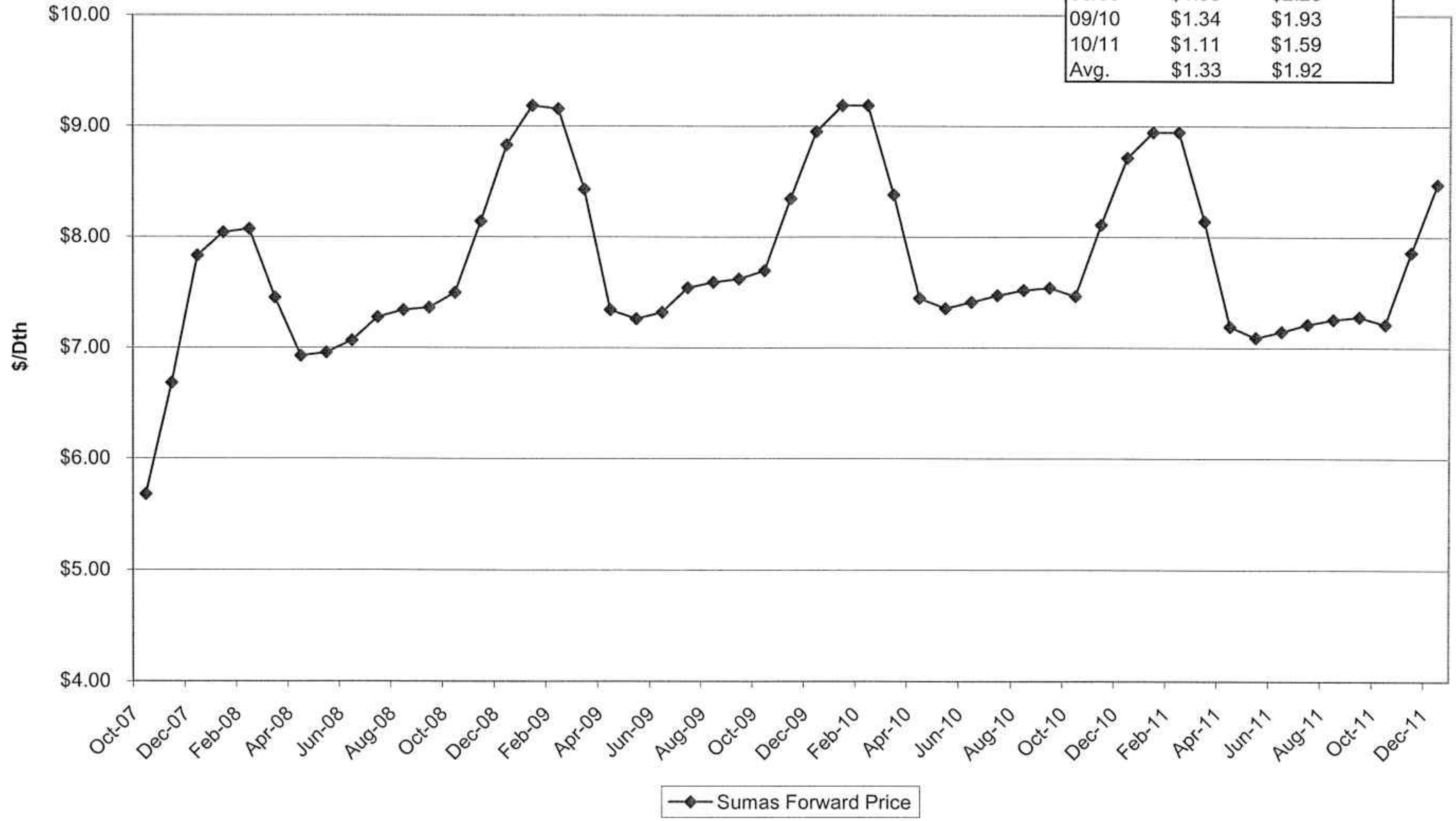
DOCKET NO. UG-___

AVISTA CORP

KEVIN J.CHRISTIE
Exhibit No. 401

Gas Supply, Storage and Pro Formed Capital Projects

Forward Markets and Pricing Differentials

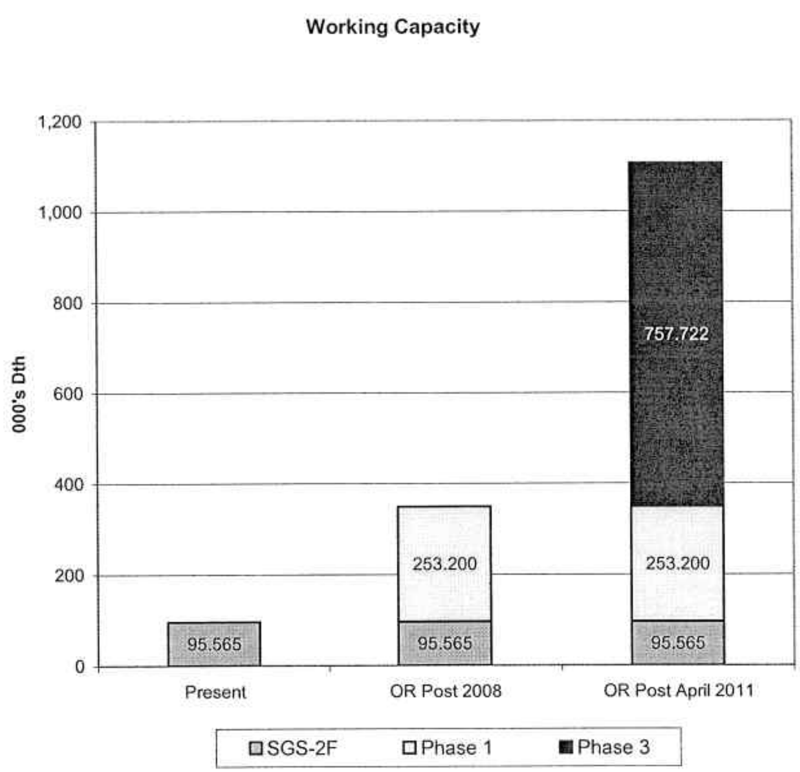


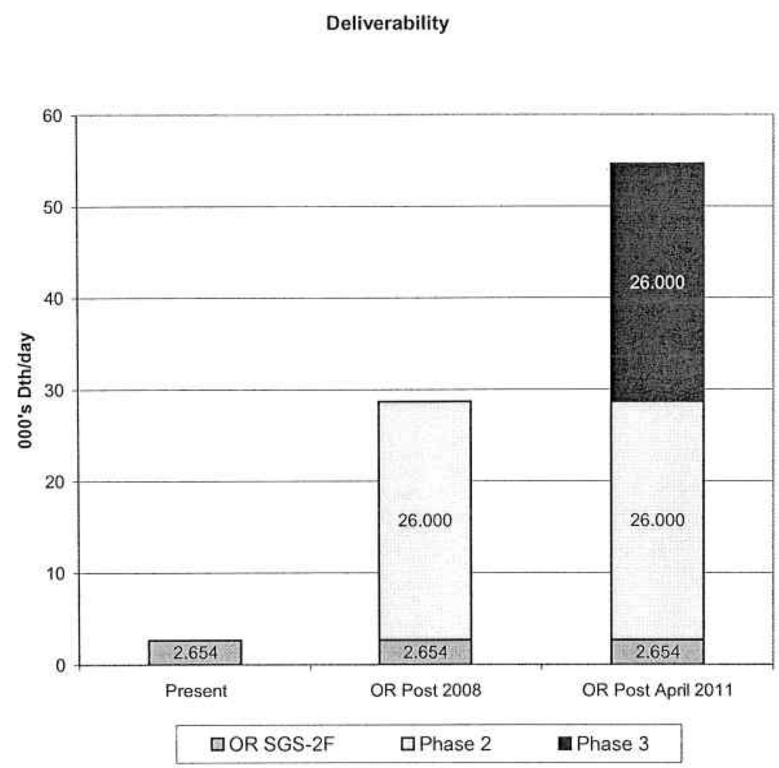
Sumas Differentials:

	Average	Max
08/09	$1.55	$2.23
09/10	$1.34	$1.93
10/11	$1.11	$1.59
Avg.	$1.33	$1.92

AVISTA UTILITIES

Current vs. Proposed JP Oregon Storage Position as of 2011





Phase 1 - 2002/2008 Jackson Prairie Capacity Expansion.
Phase 2 - 2008 Jackson Prairie Deliverability Expansion.
Phase 3 - Purchase of Jackson Prairie Capacity and Deliverability from Avista Energy in 2011.

AVISTA UTILITIES

Capacity/Deliverability Expansion Costs

Future JP Storage	Capacity			Deliveribility			Total
Source/Timing	Dth	Est. Cost		Dth	Est. Cost		Est. Cost
Phase 1 - 7/07 through Mid-08 - ESTIMATE	253,200	$ 1,394,288	1/	-	$ -		$ 1,394,288
Phase 2 - 11/08	-	$ -		104,000	$ 14,600,000	3/	$ 14,600,000
Phase 3 - April 2011	3,030,887	$ 12,600,000	2/	104,000	$ -		$ 12,600,000
	3,284,087	$ 13,994,288		208,000	$ 14,600,000		$ 28,594,288

1/ This is the cost of cushion gas (168,800 Dth) and assumes average cushion gas cost of $8.26.
2/ Estimate of the book value at 6/30/07.
3/ This is the estimated capital cost of the expansion. These expenses will be incurred through 10/08.

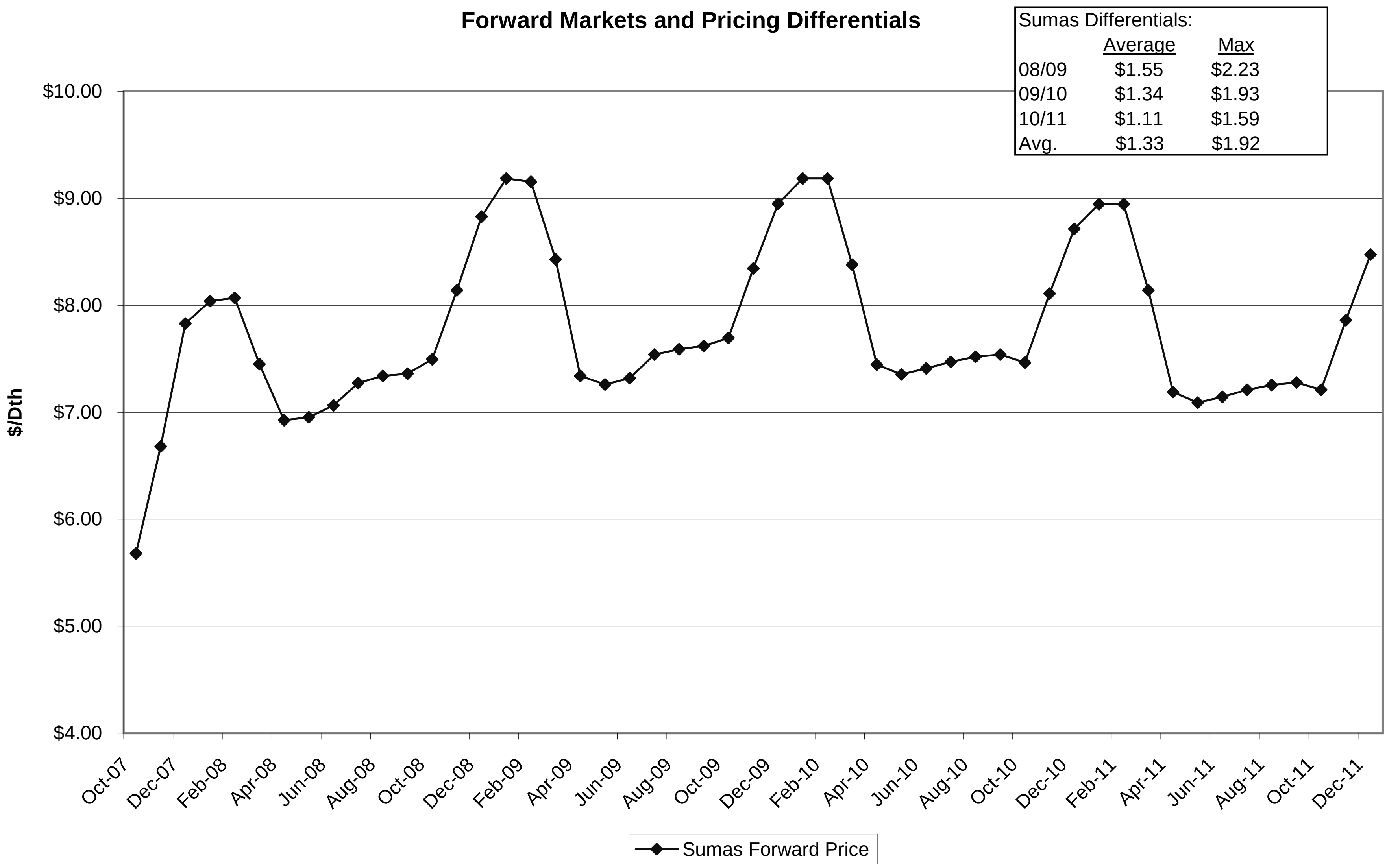
Capacity/Deliverability Expansion Jurisdictional Allocation

	Oregon	WA/ID	Total
Oregon vs. WA/ID Avg. Load 1/	25%	75%	100%

Allocation	Oregon	WA/ID	Total
Capacity	821,022	2,463,065	3,284,087
Deliveribility	52,000	156,000	208,000

1/ Based upon the 2007/2008 average load calculations from SENDOUT for the current procurement plan.

AVISTA UTILITIES



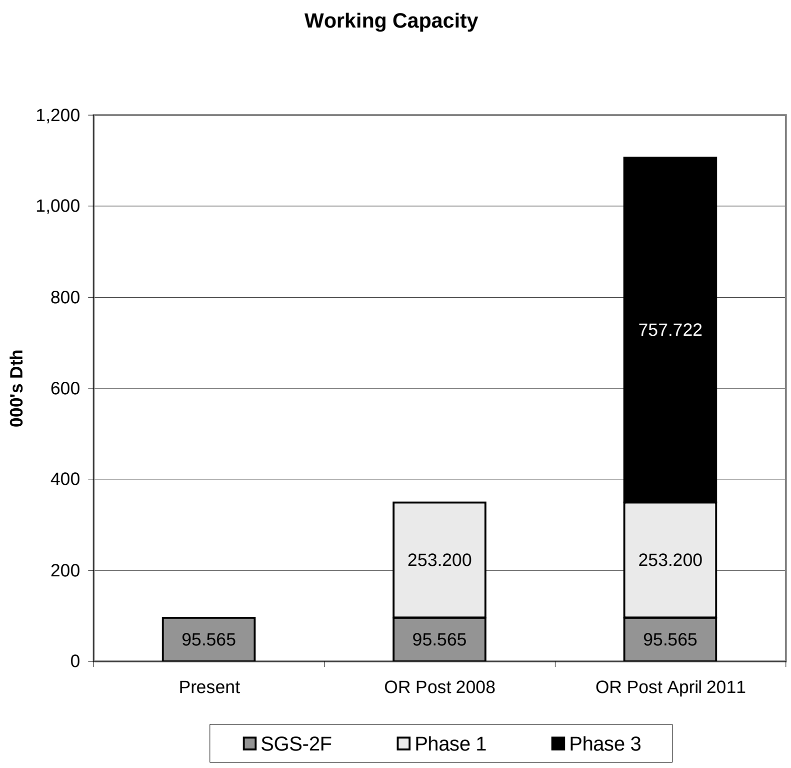
Support for Chart 1 - Exhibit 502

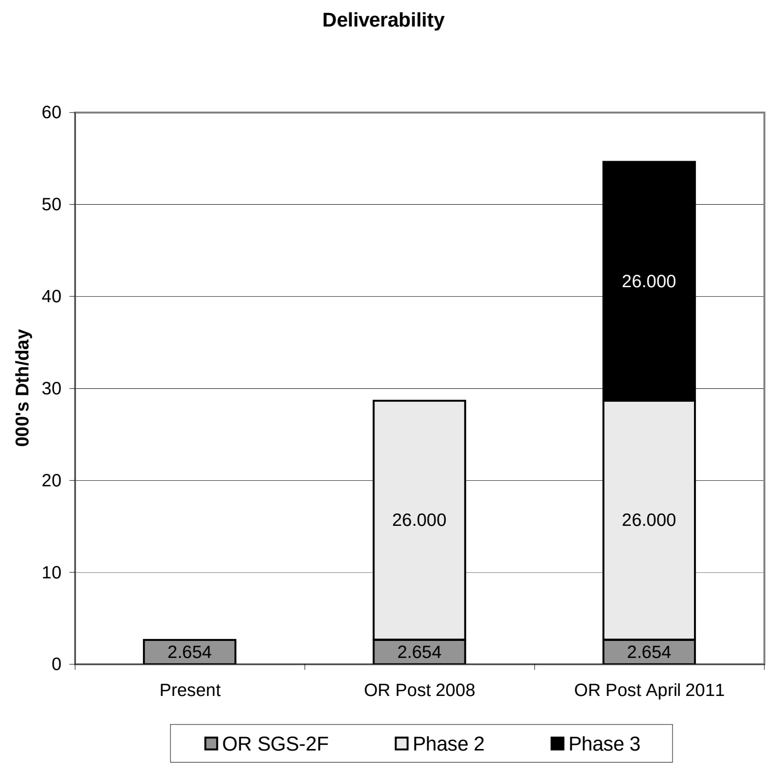
NYMEX on 09-21-07

Date	Sumas US/Mmbtu	Average Summer (May-Sept) and Average Winter (Nov-Mar) Price	Min/Max Differential	Average Summer/Winter Differential	Max Summer/Winter Differential
Oct-07	$ 5.68				
Nov-07	$ 6.68				
Dec-07	$ 7.83				
Jan-08	$ 8.04				
Feb-08	$ 8.07				
Mar-08	$ 7.45				
Apr-08	$ 6.93				
May-08	$ 6.96				
Jun-08	$ 7.07				
Jul-08	$ 7.28				
Aug-08	$ 7.34				
Sep-08	$ 7.36	$ 7.20	$ 6.96		
Oct-08	$ 7.50				
Nov-08	$ 8.14				
Dec-08	$ 8.83				
Jan-09	$ 9.19				
Feb-09	$ 9.16				
Mar-09	$ 8.43	$ 8.75	$ 9.19	$ 1.55	$ 2.23
Apr-09	$ 7.34				
May-09	$ 7.26				
Jun-09	$ 7.32				
Jul-09	$ 7.54				
Aug-09	$ 7.59				
Sep-09	$ 7.62	$ 7.47	$ 7.26		
Oct-09	$ 7.70				
Nov-09	$ 8.35				
Dec-09	$ 8.95				
Jan-10	$ 9.19				
Feb-10	$ 9.19				
Mar-10	$ 8.38	$ 8.81	$ 9.19	$ 1.34	$ 1.93
Apr-10	$ 7.45				
May-10	$ 7.36				
Jun-10	$ 7.41				
Jul-10	$ 7.47				
Aug-10	$ 7.52				
Sep-10	$ 7.54	$ 7.46	$ 7.36		
Oct-10	$ 7.47				
Nov-10	$ 8.11				
Dec-10	$ 8.72				
Jan-11	$ 8.95				
Feb-11	$ 8.95				
Mar-11	$ 8.14	$ 8.57	$ 8.95	$ 1.11	$ 1.59
Apr-11	$ 7.19				
May-11	$ 7.09				
Jun-11	$ 7.15				
Jul-11	$ 7.21				
Aug-11	$ 7.26				
Sep-11	$ 7.28				
Oct-11	$ 7.21				
Nov-11	$ 7.86				
Dec-11	$ 8.48				
Average Differntial				$ 1.33	$ 1.92

AVISTA UTILITIES

Current vs. Proposed JP Oregon Storage Position as of 2011





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AVISTA UTILITIES

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Capacity/Deliverability Expansion Jurisdictional Allocation

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Oregon vs. WA/ID Avg. Load 1/	25%	75%	100%

Allocation	Oregon	WA/ID	Total
Capacity	821,022	2,463,065	3,284,087
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1/ Based upon the 2007/2008 average load calculations from SENDOUT for the current procurement plan.

Exhibit 500
Andrews

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF ELIZABETH M. ANDREWS
REPRESENTING THE AVISTA CORPORATION

Revenue Requirement and Allocations

INTRODUCTION

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

A. My name is Elizabeth M. Andrews. I am employed by Avista Corporation as Manager of Revenue Requirements in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

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

A. I am a 1990 graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. That same year, I passed the November Certified Public Accountant exam, earning my CPA License in August 1991. I worked for Lemaster & Daniels, CPAs from 1990 to 1993, before joining the Company in August 1993. I served in various positions within the sections of the Finance Department, including General Ledger Accountant and Systems Support Analyst until 2000. In 2000, I was hired into the State and Federal Regulation Department as a Regulatory Analyst until my promotion to Manager of Revenue Requirements in early 2007. I have also attended several utility accounting, ratemaking and leadership courses.

Q. What are your responsibilities as the Manger of Revenue Requirements?

A. As Manager of Revenue Requirements, aside from special projects, I am responsible for the preparation of normalized revenue requirement and pro forma studies for the various jurisdictions in which the Company provides utility services. During the last seven years I have assisted in the Company's electric and/or natural gas general rate filings in Washington, Idaho and Oregon.

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

A. My testimony and exhibits in this proceeding will generally cover accounting and financial data in support of the Company's need for the proposed increase in rates. I will explain pro formed operating results including expense and rate base adjustments made to actual operating results and rate base. The pro forma 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 witness Mr. Hirschkorn. I will cover that revenue adjustment briefly, while his testimony will provide more in-depth discussion. Finally, I will provide an overview of the Company's system and jurisdictional allocation methodologies that have been in place since 1994.

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

A. Yes. I am sponsoring Exhibit No. 501, which was prepared under my supervision and direction. Exhibit 501 consists of worksheets, which show actual 2006 operating results, pro forma, and 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 pro forma adjustments proposed in this filing.

REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

Q. What is the Company's overall revenue requirement requested in this rate filing?

A. The Company's overall revenue requirement requested in this filing is $2.975 million or 2.3% over normalized general business revenues, as shown on Exhibit No. 501, page 2. This general increase is the amount required for the Company to recover its pro forma level of operating costs, as well as provide a reasonable return on its invested capital.

Q. When was the Company's last change to base natural gas rates in its Oregon jurisdiction?

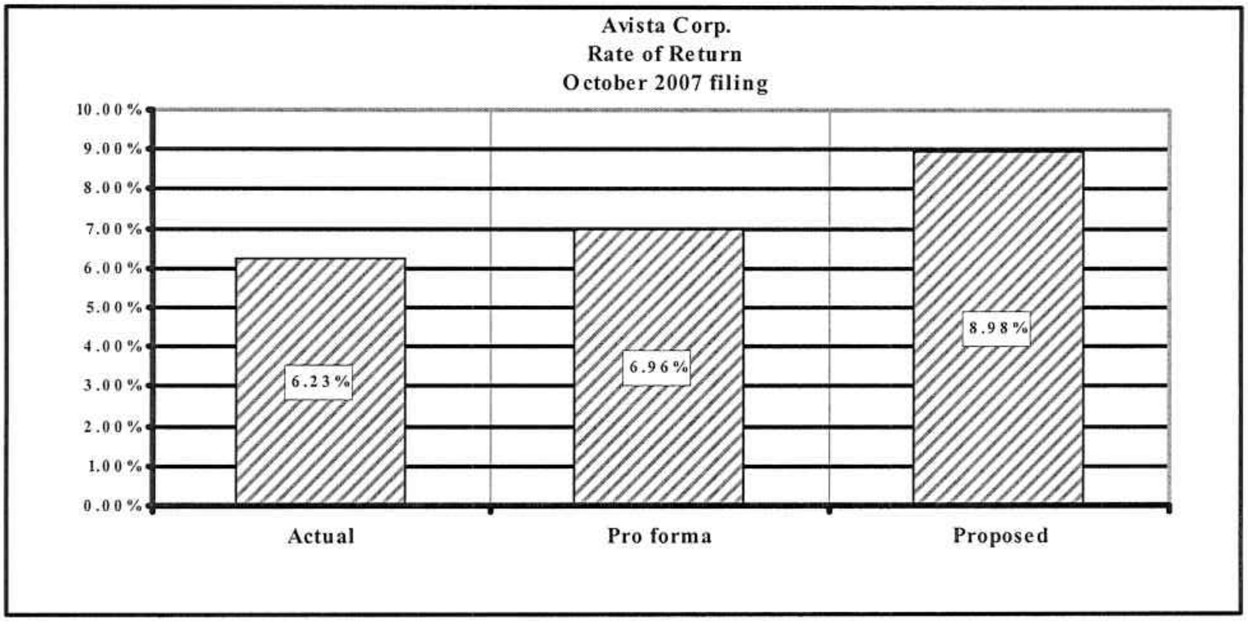
A. Pursuant to Public Utility Commission of Oregon (PUC) Order No. 03-570, the Company implemented a general rate increase of approximately 9.9% on October 1, 2003.

Q. Have there been any other previous changes to the Company's Oregon base natural gas rates since it acquired those properties in 1991?

A. Yes. In addition to the 2003 base rate increase, the Company was authorized to implement a base rate reduction of 0.5% effective with its official date of operation in 1991. That rate reduction was followed by a second general rate reduction of 2.94%, effective December 1, 1995, approximately at the end of a four and one half-year rate freeze period. Another base rate reduction of 2.1% was implemented effective December 1, 1997. When combined with the proposed overall general increase of 2.3%, base rates will have only increased 6.66% since we acquired the properties sixteen years ago.

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

A. Yes. Basically, there are three different rates of return that will be discussed. The actual ROR earned by the Company during the test period, the Pro Forma ROR determined in my Exhibit No. 501, page 1, and the requested ROR. For convenience of comparison, please refer to the following graph:



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

A. We are basing our general rate request upon the historical test period, twelve months ended December 31, 2006, which is the most recent calendar year period and corresponds to the Company's financial reporting.

PRIMARY FACTORS

Q. What are the main factors driving the Company's need for a general revenue requirement increase of $2.975 million or 2.3% over current revenues?

A. There are numerous operational factors that have impacted the Company's Oregon jurisdiction results of operations since the 2002 test year of operations used for Avista's last base rate increase in Oregon. Total Rate Base has increased approximately $21.9 million, or 31%, and the average number of customers has increased approximately 12%. In comparing the 2006 normalized test period for this filing to 2002, many operational costs have also been impacted by general inflation. At a summary level since 2002, O&M and A&G costs increased approximately $2.4 million or 28% and Taxes Other Than Income increased approximately $1.4 million or 35%.

Another impact on the Company's Oregon results of operations has been the decline in sales on a per customer basis, which translates to associated reductions in gross operating margin. This reduction in gross operating margin reduces the net revenues available to recover the Company's operating costs and cost of capital necessary to provide natural gas service to our customers in Oregon.

The average use per customer (weather normalized using the 25-year rolling average methodology) for the 2002 test period compared to the 2006 test period, declined by 5.3% for residential customers (Schedule 410) and by 1.4% for commercial customers (Schedule 420). (Previously, as noted in the 2003 rate case, the average use per customer was down by 10.6% for residential customers and 6.8% for commercial customers in the 14-month period from December 1999 to February 2001.) The declining trend in use per customer continues to erode the Company's recovery of fixed costs. The lost margin associated with the decline in usage per customer amounts to $766,000 for residential customers and $81,000 for commercial customers on an annual basis since 2002.

In later testimony, Mr. Hirschkorn will explore in more detail the changes that have occurred to customer usage among the Company's various customer classes.

Q. Please explain the major components of the $21.9 million increase in total rate base.

A. The gross plant increased approximately $44 million, with an offsetting increase in Accumulated Depreciation and Amortization of approximately $16 million and a Deferred Federal Income Tax increase of approximately $6 million.

Q. What were the major components of the $44 million of gross plant additions?

A. Gross plant increased approximately $44 million, or a little over 31% as compared to what is currently included in rates. This includes the actual plant additions from 2002 through 2006 of approximately $34.5 million and the pro formed capital additions of approximately $9.5 million. The 2002 through 2006 capital additions were primarily distribution plant that was necessary to continue to meet the energy and reliability needs of our customers.

The pro forma capital projects included in this filing include the Glendale Conversion to Natural Gas, the East Medford Reinforcement Project, the Integrity Management Pipe Replacement Project, the Roseburg Reinforcement Project, and the Merlin Gate Station Project. Company witness Mr. Christie sponsors testimony that details these projects. The table below includes the five projects that have been included in pro forma period results, listing the estimated gross costs and their expected in-service dates.

Project	Estimated Cost	In-Service Date
Glendale Conversion to Natural Gas	$ 961,150	Sept. 2007
East Medford Reinforcement Project	$3,150,000	July 2008
Integrity Management Pipe Replacement Project	$3,230,000	Dec. 2007
Roseburg Reinforcement Project	$1,680,000	March 2008
Merlin Gate Station Project	$ 473,000	March 2008

Later in my testimony, I will address the $9.494 million net rate base adjustment labeled "Pro Forma Capital Additions Adjustment" included in Exhibit No.501, page 6, which explains the detail behind the pro forma net operating income and rate base adjustments.

Q. Could you please provide some additional detail regarding the operational expenses that had significant increases experienced by the Company's Oregon jurisdiction in the last four years?

A. Yes.

Depreciation and Amortization Expense: Recorded depreciation and amortization expense increased \$1.4 million, or 26%. Of that total, depreciation on distribution plant increased \$1.3 million, or almost 94% of the total increase. The changes in depreciation and amortization costs are consistent with the change in gross plant.

Other Taxes: Taxes Other than Income is a combination of property taxes and franchise taxes, also known as business and occupation taxes. Property taxes increased approximately \$402,000, while franchise taxes increased approximately \$990,000. The increase in property taxes is consistent with the increase in gross utility plant. Individual area franchise fees, up to an imposed rate of 3%, are a general cost spread to all customers. The increase in franchise taxes can be explained by the customer growth experienced by the Company and the increase in gross revenue levels that have increased due to changes in commodity costs.

GENERAL REVENUE REQUIREMENT

Q. Would you please explain what is shown in Exhibit 501?

A. Yes. Exhibit 501 shows actual and pro forma natural gas operating results and rate base for the test period for the Company's Oregon jurisdiction. Column (b) of page 1 of Exhibit 501 shows twelve months ended December 31, 2006 operating results and components of the average-of-monthly-average rate base as recorded; column (c) is the total of all adjustments to net operating income and rate base; and column (d) is pro forma results of operations, all under existing rates. Column (e) shows the revenue increase required which would allow the Company an opportunity to earn its requested 8.98% rate of return. Column (f) reflects pro forma natural gas operating results with the requested general increase of $2,975,000.

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

A. Yes. As explained earlier in my testimony, page 2 shows the calculation of the $2,975,000 revenue requirement using the requested 8.98% rate of return.

Q. Would you now please explain page 3 of Exhibit 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. Federal income taxes are reflected at 35%.

Q. Now turning to pages 4 through 6 of your Exhibit 501, would you please explain what those pages show?

A. Yes. Page 4 begins with actual operating results and rate base for the test period in column (b). Individual normalizing adjustments that are standard components of our annual normalized earnings reporting to the Commission begin in column (c) on page 4 and continue through column (k) on page 5. Column (l) on page 5, entitled Restated Total, is the subtotal of all preceding columns. The four individual pro forma adjustments are presented in column (PF1) through column (PF4) on page 6.

NORMALIZING ADJUSTMENTS

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

A. Yes. The first adjustment, column (c) on page 4, entitled **Deferred FIT Rate Base**, reflects an adjustment to the rate base reduction for Oregon's portion of deferred federal income taxes. Deferred FIT Rate Base reflects the deferred tax balances arising from accelerated tax depreciation (Accelerated Cost Recovery System, ACRS, and Modified Accelerated Cost Recovery, MACRS), bond refinancing premiums, and contributions in aid of construction. The beginning amount noted in column (b) was an estimate used for monthly reporting, and as adjusted, total Deferred FIT Rate Base is $15,630,000. The effect of this adjustment on state of Oregon rate base is an increase of $3,106,000.

Column (d), **Memberships and Dues**, classifies expenses by category and specific percentages are applied to determine the recoverable amounts. This calculation is consistent with what was recommended to the Company during Staff review of December 31, 1994 Earnings Report. The effect of this adjustment on state of Oregon net operating income is an increase of $20,000.

The adjustment in column (e), **Incentive Pay**, adjusts 2006 test year incentive expense to the actual 2006 incentive expense paid in 2007, reflects a 50/50 sharing of merit-based incentive pay between the Company and customers, and removes any part of the executive incentive payout that is based on meeting Company strategic financial goals. Incentive pay was available to employees through two programs, a Pacesetter Program for individual performance and the overall 2006 Incentive Plan for corporate performance. The Company's main employee incentive plan uses Customer Satisfaction and Reliability targets as the initial step in issuing incentive payouts. Actual payouts are dictated by O&M cost savings at the individual department level. Since the executive plan is slightly different than the main employee incentive plan, this adjustment removes any part of the 2006 executive incentive payout that was not based on the Customer Satisfaction and Reliability targets. This adjustment also removes other prior period and non-recurring items impacting test period operating income. The effect of this adjustment on state of Oregon net operating income is an increase of $77,000.

The adjustment in column (f), **Eliminate Revenue Pass-Through**, has no impact on the Company's revenue requirement. This adjustment removes the impact of the collection through revenues of franchise taxes that exceed the general level of 3% and the impact of the collection of Low-Income Rate Assistance Plan (LIRAP) revenues from results of operations. The impact of both of these items nets to zero and facilitates analysis of cost of service and rate design.

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

A. Column (g), **Uncollectible Expense**, revises the test period level of accrued expense to a three-year average of actual net uncollectible customer write-offs. The effect on state of Oregon net operating income is a decrease of $154,000.

The adjustment in column (h), **Miscellaneous**, removes prior period and non-recurring items impacting 2006 test period operating income. The impact of this adjustment on Oregon net operating income is a decrease of $66,000.

Column (i), **Remove Senate Bill 408 Accrual**, removes the entry recorded in December 2006 that recognized a potential Oregon Senate Bill 408 tax refund to customers for calendar year 2006. The adjustment increases net operating income by $845,000.

The adjustment in column (j), **SIT-FIT**, adjusts Oregon state income tax expense and federal income tax expense applicable to Oregon gas utility operations. Avista Corporation files a consolidated federal income tax return for an affiliated group that includes electric utility operations in Washington and Idaho, gas utility operations in Oregon, Washington, and Idaho, and non-utility subsidiary operations.

Federal income tax expense is determined for Oregon gas utility operations on a standalone basis, or, in other words, based on the income generated by Oregon gas operations. The ($71,000) adjustment to current federal income tax expense relates to the federal income tax impact of the adjustment to Oregon state income tax. The $221,000 adjustment to deferred federal income tax relates to correcting a deferred tax expense item that should have been directly assigned to Oregon gas operations, but was mistakenly allocated to utility operations in all jurisdictions.

Unlike federal income tax, Oregon state income tax is <u>not</u> determined on a standalone basis. Rather, Oregon state income tax is determined by applying a 4-factor apportionment percentage to the federal taxable income of the consolidated affiliated group of the corporation. The 4-factor apportionment percentage used by the Oregon Department of Revenue is based on property, payroll, sales, and sales, again, within the state of Oregon as percentages of the amounts for the total corporation. Each of the 4 factors is weighted equally.

Applying the 4-factor apportionment to the federal taxable income of the affiliated group determines the amount of Oregon taxable income. The state statutory rate of 6.6% is then applied to determine the amount of Oregon state income tax.

The Oregon state income tax return for the 2005 calendar year, with several adjustments, was used to determine the pro forma amount of Oregon state income tax for the test period. The most significant adjustment was to reflect the sale of Avista Energy, a non-utility subsidiary operation involved in energy marketing and resource management. Other adjustments include the purchase of the general office building, the sale of California gas operations, and acquisition of 100% ownership in Coyote Springs 2, a combined-cycle, natural gas-fired combustion turbine located in Oregon.

After determining the amount of pro forma Oregon state income tax, the amount was then allocated between Oregon gas operations and electric operations. Since Coyote Springs 2 is located in Oregon, and is reflected in the Oregon 4-factor apportionment percentage, about half of the pro forma Oregon state income tax was assigned to electric operations. The pro forma amount assigned to Oregon gas operations of $505,000 was compared to the $302,000 amount in the test period, with the adjustment being $203,000.

The net impact to Oregon net operating income for federal and state income taxes is a reduction of $353,000.

Column (k), entitled **Restate Debt Interest**, restates debt interest using the Company's pro forma weighted average cost of debt, as outlined in the testimony and exhibits of Company witness Mr. Malquist and applied to Oregon's pro forma level of rate base to produce a pro forma level of tax deductible interest expense. The federal income tax effect of the restated level of interest for the test period increases Oregon net operating income by $25,000.

Column (l) provides a subtotal of preceding columns and represents actual operating results and rate base, plus the standard rate base adjustments that have been included in prior annual earnings reporting to the Oregon Commission.

PRO FORMA ADJUSTMENTS

Q. Please turn to page 6 and explain the significance of the four columns that begin on that page in your Exhibit 501.

A. Certainly. The four adjustments are signified by a PF with an identifying digit, 1 through 4. These adjustments bring the operating results and rate base to the final pro forma level for the test period.

Q. Please continue with your explanation of the pro forma adjustments on page 6.

A. Column (PF1), **Pro Forma Revenue Adjustment**, takes into account known and measurable changes that include revenue normalization, weather normalization and an unbilled revenue calculation. It encompasses restating revenues and purchased gas expense based on rates and associated gas costs approved in the Company's most recent Purchased Gas Adjustment filing. Mr. Hirschkorn is sponsoring this adjustment, the effect of which is to decrease Oregon net operating income by $411,000.

Column (PF2), **Pro Forma Labor Adjustment**, brings 2006 test period wages forward to 2008 levels. The adjustment decreases Oregon net operating income by $246,000.

Column (PF3), **Pro Forma Depreciation Adjustment**, reflects a decrease in depreciation expense due to the utilization of new depreciation rates that were the result of a detailed depreciation study performed by a consultant from Gannett Fleming, Inc. The Company has not changed its depreciation rates since acquiring the Oregon operations in 1991. The Company has filed a Petition to file a Depreciation Study concurrent with this general rate filing. This adjustment increases Oregon net operating income by $2,009,000 and increases rate base by $1,010,000.

Column (PF4), **Pro Forma Capital Additions**, pro forms in the capital cost and expenses associated with five major capital projects. This adjustment includes projects expected to be completed and transferred to plant-in-service by July 2008, in time for new rates to be approved. The capital costs have been averaged for their appropriate pro forma period with the associated depreciation expense and property tax, as well as the appropriate accumulated depreciation and deferred income tax rate base offsets. This adjustment decreases Oregon net operating income by $226,000 and increases rate base by $9,443,000.

ALLOCATION PROCEDURES

Q. Have there been any changes to the Company's system and jurisdictional procedures since the Company's last general natural gas case, Docket No. UG-153?

A. No. For ratemaking purposes, the Company 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 was implemented in 1994 and has not changed. In this filing, consistent with the accepted allocation methodology, the Company reflected the reallocation of costs resulting from the sale of the Company's California gas distribution properties in April 2005. In Andrew's work papers, pages B30 through B33, the Company also describes in detail the allocation methodology used by the Company.

Q. Does that conclude your pre-file, direct testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

ELIZABETH M. ANDREWS
Exhibit No. 501

Revenue Requirement and Allocations

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON JURISDICTION PRO FORMA RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2006
(000'S OF DOLLARS)

		WITH PRESENT RATES			WITH PROPOSED RATES	
Line No.	**DESCRIPTION**	**Actual Per Results Report**	**Total Adjustments**	**Pro Forma Total**	**Proposed Revenues & Related Exp**	**Pro Forma Proposed Total**
	a	*b*	*c*	*d*	*e*	*f*
	OPERATING REVENUES					
1	Total General Business	$122,020	$2,514	$124,534	$2,975	$127,509
2	Total Transportation	2,558	322	2,880		2,880
3	Other Revenues	44,300	(44,187)	113		113
4	Total Operating Revenues	168,878	(41,351)	127,527	2,975	130,502
	OPERATING EXPENSES					
5	Gas Purchased	133,761	(38,430)	95,331		95,331
6	Operation and Maintenance	9,100	(226)	8,874	16	8,890
7	Administration & General	5,847	61	5,908	8	5,916
8	Taxes Other than Income	5,450	(1,399)	4,051	59	4,110
9	Depreciation & Amortization	8,139		3,933		3,933
10	Total Operating Expenses	162,297	(39,994)	118,097	83	118,180
11	OPERATING INCOME BEFORE FIT	6,581	(1,357)	9,430	2,892	12,322
	INCOME TAXES					
12	Current Federal Income Taxes	2,721	443	3,164	1,007	4,171
13	Deferred Federal Income Taxes	(1,366)	676	(690)		(690)
14	State Income Taxes	303	210	513	14	527
15	Total Income Taxes	1,658	1,329	2,987	1,021	4,008
						0
16	NET OPERATING INCOME	$4,923	($2,686)	$6,443	$1,871	$8,314
	AVERAGE RATE BASE					
17	Utility Plant in Service	174,441	9,494	183,935		183,935
18	Less: Accum Depr and Amort	(77,663)	1,465	(76,198)	0	(76,198)
19	Net Utility Plant	96,778	10,959	107,737	0	107,737
20	Accumulated Deferred FIT	(18,736)	2,600	(16,136)		(16,136)
21	Inventory and Other	971	0	971	0	971
22	TOTAL AVERAGE RATE BASE	$79,013	$13,559	$92,572	$0	$92,572
23	RATE OF RETURN	6.23%		6.96%		8.98%

AVISTA UTILITIES
Calculation of General Revenue Requirement
Oregon Natural Gas Jurisdiction
TWELVE MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	(000's of Dollars)
1	Pro Forma Rate Base	\$92,572
2	Proposed Rate of Return	8.980%
3	Net Operating Income Requirement	\$8,313
4	Pro Forma Net Operating Income	\$6,443
5	Net Operating Income Deficiency	\$1,870
6	Conversion Factor	0.62862
7	Revenue Requirement	\$2,975
8	Total General Business Revenues	\$127,414
9	Percentage Revenue Increase	2.3%

AVISTA UTILITIES
Calculation of Conversion Factor
Oregon Natural Gas Jurisdiction
TWELVE MONTHS ENDED DECEMBER 31, 2006

Line No.	Description		Factor
1	Revenues		1.000000
	Expense:		
2	Uncollectibles		0.005231
3	Commission Fees		0.002500
4	Energy Resource Supplier Assessment		0.000479
5	Franchise Fees		0.019846
6	Oregon Excise Tax		0.004837
6	Total Expense		0.032893
7	Net Operating Income Before FIT		0.967107
8	Federal Income Tax @	35.00%	0.338487
9	REVENUE CONVERSION FACTOR		0.628620

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON PRO FORMA RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2006
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Per Results Report	Deferred FIT Rate Base	Subtotal Actual	Memberships & Dues Adj.	Incentive Pay Adj.	Eliminate Pass-Thru Revenue
	a	b	c	-	d	e	f
	REVENUES						
1	Total General Business	$122,020		$122,020			$ (1,619)
2	Total Transportation	2,558		2,558			(21)
3	Other Revenues	44,300		44,300			
4	Total Gas Revenues	168,878	0	168,878	0	0	(1,640)
	EXPENSES						
5	Exploration and Development	0		0			
	Production						
6	City Gate Purchases	133,761		133,761			
7	Purchased Gas Expense	0		0			
8	Other Gas Expenses	418		418			
9	Depreciation	1		1			
10	Taxes	1		1			
11	Total Production	134,181	0	134,181	0	0	0
	Transmission						
12	Operating Expenses	0		0			
13	Depreciation	0		0			
14	Taxes	0		0			
15	Total Transmission	0	0	0	0	0	0
	Distribution						
16	Operating Expenses	4,791		4,791			
17	Depreciation	6,079		6,079			
18	Taxes	5,372		5,372			(1,640)
19	Total Distribution	16,242	0	16,242	0	0	(1,640)
20	Customer Accounting	2,640	0	2,640	0	0	0
21	Customer Service & Information	983		983			
22	Sales Expenses	268		268			
	Administrative & General						
23	Operating Expenses	5,847		5,847	(31)	(120)	
24	Depreciation & Amortization	2,059		2,059			
25	Taxes	77		77			
26	Total Admin. & General	7,983	0	7,983	(31)	(120)	0
27	Total Gas Expense	162,297	0	162,297	(31)	(120)	(1,640)
28	OPERATING INCOME BEFORE FIT	6,581	0	6,581	31	120	0
	FEDERAL INCOME TAX						
29	Current Accrual	2,721		2,721	11	42	
30	Deferred FIT	(1,366)		(1,366)			
31	State Income Tax	303		303		1	
32	NET OPERATING INCOME	$4,923	$0	$4,923	$20	$77	$0
	RATE BASE: PLANT IN SERVICE						
33	Production Plant	75		75			
34	Transmission Plant	0		0			
35	Distribution Plant	162,822		162,822			
36	General Plant	11,544		11,544			
37	Total Plant in Service	174,441	0	174,441	0	0	0
	ACCUMULATED DEPRECIATION						
38	Production Plant	(70)		(70)			
39	Transmission Plant	0		0			
40	Distribution Plant	73,395		73,395			
41	General Plant	4,338		4,338			
42	Total Accum. Depreciation	77,663	0	77,663	0	0	0
43	DEFERRED FIT	(18,736)	3,106	(15,630)			
44	GAS INVENTORY	971		971			
45	TOTAL RATE BASE	$79,013	$3,106	$82,119	$0	$0	$0
46	RATE OF RETURN	6.23%		5.99%			

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON PRO FORMA RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2006
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Uncollectible Expense	MISC Adj	Remove SB 408 Accrual	SIT - FIT Adjustment	Restate Debt Interest	Restated Total
	a	g	h	i	j	k	l
	REVENUES						
1	Total General Business						$120,401
2	Total Transportation						2,537
3	Other Revenues						44,300
4	Total Gas Revenues	0	0	0	0	0	167,238
	EXPENSES						
5	Exploration and Development						0
	Production						
6	City Gate Purchases						133,761
7	Purchased Gas Expense						0
8	Other Gas Expenses						418
9	Depreciation						1
10	Taxes						1
11	Total Production	0	0	0	0	0	134,181
	Transmission						
12	Operating Expenses						0
13	Depreciation						0
14	Taxes						0
15	Total Transmission	0	0	0	0	0	0
	Distribution						
16	Operating Expenses						4,791
17	Depreciation						6,079
18	Taxes						3,732
19	Total Distribution	0	0	0	0	0	14,602
20	Customer Accounting	238	0	0	0	0	2,878
21	Customer Service & Information						983
22	Sales Expenses						268
	Administrative & General						
23	Operating Expenses		103				5,799
24	Depreciation & Amortization			$ (1,300)			759
25	Taxes						77
26	Total Admin. & General	0	103	(1,300)	0	0	6,635
27	Total Gas Expense	238	103	(1,300)	0	0	159,547
28	OPERATING INCOME BEFORE FIT	(238)	(103)	1,300	0	0	7,691
	FEDERAL INCOME TAX						
29	Current Accrual	(83)	(36)		(71)	(25)	2,559
30	Deferred FIT			$455	221		(690)
31	State Income Tax	(1)	(1)		203		505
32	NET OPERATING INCOME	($154)	($66)	$845	($353)	$25	$5,317
	RATE BASE: PLANT IN SERVICE						
33	Production Plant						75
34	Transmission Plant						0
35	Distribution Plant						162,822
36	General Plant						11,544
37	Total Plant in Service	0	0	0	0	0	174,441
	ACCUMULATED DEPRECIATION						
38	Production Plant						(70)
39	Transmission Plant						0
40	Distribution Plant						73,395
41	General Plant						4,338
42	Total Accum. Depreciation	0	0	0	0	0	77,663
43	DEFERRED FIT						(15,630)
44	GAS INVENTORY						971
45	TOTAL RATE BASE	$0	$0	$0	$0	$0	$82,119
46	RATE OF RETURN						6.47%

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON PRO FORMA RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2006
(000'S OF DOLLARS)

Line No.	DESCRIPTION	Pro Forma Revenue Adjustment	Pro Forma Labor Adjustment	Pro Forma Depreciation Adjustment	Pro Forma Capital Additions Adjustment	Pro Forma Total
	a	PF1	PF2	PF3	PF4	-
	REVENUES					
1	Total General Business	$4,133				$124,534
2	Total Transportation	343				2,880
3	Other Revenues	(44,187)				113
4	Total Gas Revenues	(39,711)	0	0	0	127,527
	EXPENSES					
5	Exploration and Development					0
	Production					
6	City Gate Purchases	(38,430)				95,331
7	Purchased Gas Expense					0
8	Other Gas Expenses	(6)	18			430
9	Depreciation			2		3
10	Taxes					1
11	Total Production	(38,436)	18	2	0	95,765
	Transmission					
12	Operating Expenses					0
13	Depreciation					0
14	Taxes					0
15	Total Transmission	0	0	0	0	0
	Distribution					
16	Operating Expenses		180			4,971
17	Depreciation			(3,122)	200	3,157
18	Taxes	91			150	3,973
19	Total Distribution	91	180	(3,122)	350	12,101
20	Customer Accounting	23	79	0	0	2,980
21	Customer Service & Information	(764)				219
22	Sales Expenses		6			274
	Administrative & General					
23	Operating Expenses	11	98			5,908
24	Depreciation & Amortization			14		773
25	Taxes					77
26	Total Admin. & General	11	98	14	0	6,758
27	Total Gas Expense	(39,075)	381	(3,106)	350	118,097
28	OPERATING INCOME BEFORE FIT	(636)	(381)	3,106	(350)	9,430
	FEDERAL INCOME TAX					
29	Current Accrual	(222)	(133)	1,082	(122)	3,164
30	Deferred FIT					(690)
31	State Income Tax	(3)	(2)	15	(2)	513
32	NET OPERATING INCOME	($411)	($246)	$2,009	($226)	$6,443
	RATE BASE: PLANT IN SERVICE					
33	Production Plant					75
34	Transmission Plant					0
35	Distribution Plant				9,494	172,316
36	General Plant					11,544
37	Total Plant in Service	0	0	0	9,494	183,935
	ACCUMULATED DEPRECIATION					
38	Production Plant			1		(69)
39	Transmission Plant					0
40	Distribution Plant			(1,561)	88	71,922
41	General Plant			7		4,345
42	Total Accum. Depreciation	0	0	(1,553)	88	76,198
43	DEFERRED FIT			(543)	37	(16,136)
44	GAS INVENTORY					971
45	TOTAL RATE BASE	$0	$0	$1,010	$9,443	$92,572
46	RATE OF RETURN					6.96%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF TARA L. KNOX
REPRESENTING THE AVISTA CORPORATION

Long-Run Incremental Cost

INTRODUCTION

Q. Would you please state your name, business address and present position with Avista Corporation?

A. My name is Tara L. Knox. My business address is East 1411 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 cost of service models for the Company as well as providing support in the preparation of pro forma results of operations studies and miscellaneous other duties as required.

Q. Would you please describe your educational background?

A. I graduated from Washington State University with a Bachelor of Arts degree in General Humanities in 1982 and a Master of Accounting degree in 1990. As an employee in the rate department of Avista Corp (and WWP) since 1991, I have attended several rate-making classes, including the EEI Electric Rates Advanced Course which specializes in cost allocation and cost of service issues.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I have testified before the Oregon, Washington and Idaho Commissions regarding cost of service and weather normalization.

Q. Would you please briefly summarize your testimony?

A. My testimony covers the weather normalization adjustment and the cost of service study prepared for this filing. The weather normalization adjustment is based on a 25 year rolling average for normal heating degree days and regression analysis of monthly billed usage per customer during the heating season. The results of the long-run incremental cost study indicate, that at current rates, residential customers are in line with cost of service, small commercial customers are paying less than their cost of service, while all other customer groups exceed their cost of service to varying degrees. An embedded cost study provided similar results, although it indicated that both residential and small commercial customers were under-earning.

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

A. Yes. I am sponsoring Exhibit No. 601, which is the Company's long-run incremental cost (LRIC) study.

Q. Was this exhibit prepared by you?

A. Yes, it was.

WEATHER NORMALIZATION

Q. Please describe the process used to arrive at the weather normalization adjustment Company witness Mr. Hirschkorn includes in the Revenue Normalization Adjustment?

A. Weather sensitivity factors for each customer subgroup are multiplied by 1) the average number of customers in the subgroup during the test period heating season, and 2) the difference between normal heating degree days and test period heating degree days. The subgroup results are then summed to get the Oregon total usage adjustment.

Q. What are the customer subgroups referred to above?

A. The Company serves customers in four distinct weather zones in the state of

Oregon. The zones are Medford, Roseburg, Klamath Falls, and La Grande. Within each zone, residential (Schedule 410) and small commercial (Schedule 420) customers were found to be weather sensitive. This results in eight customer subgroups.

Q. How are the weather sensitivity factors developed?

A. A regression analysis was performed for each subgroup using three heating seasons of monthly billed usage per customer and corresponding monthly heating degree day data. Heating seasons consist of the months October through May, so the billed data was derived from October 2003 to May 2006. The least squares regression procedure results in the equation: USECUST = INTERCEPT + SLOPE x HDD. The SLOPE is the weather sensitivity factor per customer per heating degree day.

Q. How are normal heating degree days defined?

A. Normal heating degree days are based on a rolling 25-year average of heating degree days reported for each month for the Medford, Roseburg, Klamath Falls, and La Grande weather stations. The 25 years are included on a heating season basis, July through June, so the October average reflects all of the Octobers beginning in 1981 and through 2005. The May average reflects all of the Mays beginning in 1982 and through 2006. Each year the normal values will be adjusted to capture the next heating season with the oldest heating season dropping off, thereby encapsulating the most recent information available at the end of each calendar year.

Q. Is this proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Oregon?

A. In most respects, yes. The regression analysis process and customer subgroups as well as the winter heating season definitions are all the same as the process utilized in Docket No. UG-153. However, in that case the NOAA (National Oceanographic & Atmospheric Administration) published 30-year averages were used to define "normal" heating degree days for the four weather stations. In this case, the Company is using a 25-year average instead.

Q. Why are you proposing to change from a 30-year to a 25-year average for normal heating degree days?

A. The NOAA normal publication is only updated every ten years, so those statistics now reflect 1971 to 2000 data, which does not include the most current weather. During the years since the last NOAA publication, Oregon has continued to experience consistently warmer than usual weather. Therefore, use of the outdated NOAA published data may tend to overstate expected heating requirements. Moving to a shorter average period, and maintaining the rolling average to keep current with the weather that has been experienced in Avista's territory, helps to overcome the limitations of the published "normal" data. Additionally, Northwest Natural has been allowed to utilize a 25-year rolling average to define normal weather.

Q. What were the results of the weather normalization calculation for the 2006 test period?

A. During 2006 heating months, weather was slightly warmer than normal in Medford, while it was colder than normal in Roseburg, Klamath Falls and La Grande. Since a large proportion of the Company's customer base is in the Medford weather zone, the additional usage for Medford largely offsets the reduction in usage in the other zones, resulting in a 0.68% net reduction to residential and small commercial consumption during the test year.

LONG-RUN INCREMENTAL COST STUDY

Q. What is a long-run incremental cost study and what is its purpose?

A. A long-run incremental cost study is an engineering-economic study which estimates the incremental annual cost of providing natural gas service to customers segregated into groups according to their usage characteristics. In the Company study, customers are grouped 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. It is my understanding that LRIC is the preferred cost of service analysis tool for rate-making purposes in the state of Oregon.

Q. What are the elements of the LRIC study?

A. The elements of the cost study include incremental plant investment, incremental operating and maintenance expenses, and the cost of gas supplied to a customer. All of the information is accumulated in terms of cost per customer for an average or typical member of each rate schedule.

Incremental Investment Costs

Q. What is included in incremental plant investment?

A. Plant investment required for a new customer includes a gas main extension to reach the customer, a service line to connect the customer to the main, and metering equipment at the customer's premises. The distribution system must be capable of meeting the combined peak needs of all customers at reliable pressure, so incremental capacity investment is required for new customer loads over the long term. Additionally, mandated safety requirements cause incremental costs to the distribution system for the benefit of all customers.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit 601 page 2 itemizes the various investment costs included in this study.

Q. How were the investment costs quantified in this study?

A. Typical main extensions were quantified in terms of the size and length of pipe recently provided for customers, multiplied by the most recent Oregon division cost-per-foot for each pipe size. Recent Oregon project work orders were used to identify the average length and typical size of pipe to serve different sizes of customers. Interruptible and transportation customers, that have not had recent installations, were individually examined to determine average current cost of pipe that is dedicated to them. Special contract customers were assigned their estimated bypass cost.

Services were quantified by the size of pipe typically needed for the type of customer. For interruptible and transportation customers, the identified dedicated pipe was 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 2006 average installed cost.

Q. How was incremental capacity investment quantified?

A. The costs of two specific recent system capacity investments, divided by the related increase in maximum daily therms provided by those investments, were averaged to quantify the current cost for incremental capacity. The resulting cost per design day therm of incremental capacity was divided by days in the year to arrive at a 100% load factor cost per therm shown on line 13 (Exhibit 601 page 2). 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 mandated safety-related incremental main investment quantified?

A. The cost of the 2007 integrity management investment in Medford, discussed in Company witness Mr. Christie's testimony, was divided by test year annual throughput to arrive at the average safety-related main investment per therm. This per therm cost is then applied to average annual consumption per customer to get safety-related main investment per customer for each schedule.

Q. Exhibit 601 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, and mains as these assets have 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 investment. The model accounts for property taxes, depreciation expense, cost of capital, operating and maintenance expenses, administrative and general expenses, income taxes, and revenue-sensitive expenses. The cost of capital and revenue-sensitive expense assumptions match with those used for Company witness Ms. Andrew's revenue requirement calculations.

<u>**Operating Expenses**</u>

Q. What is included in gas supply and customer service related incremental operating and maintenance expenses?

A. This category attempts to capture the current costs associated with gas scheduling and planning, meter reading, and billing customers.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit 601 page 3 itemizes the various operating and maintenance expenses included in this study.

Q. Please explain the items shown on Exhibit 601 page 3.

A. Gas supply schedulers schedule and track all the natural gas being delivered at all delivery points on the system, including the 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 the test year, resulting in an estimate of the annual hours necessary for these services. The annual hours were then divided by the number of customers served to arrive at the hours per customer shown on page 3, line 1.

The long run cost of gas management planning was estimated by dividing the hours charged by gas planning staff to FERC Account 813 "Other Gas Expenses" during the test year by the number of gas customers served to arrive at the annual hours per customer shown on page 3, line 4.

Similarly, the resource accounting hours dedicated to manually billing interruptible and transportation customers were divided by the number of customers billed to get the annual hours per customer for that function. The total hours charged to meter reading in 2006 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 the test year 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.

Cost of Gas Commodity

Q. What is included in the cost of gas?

A. In this portion of the study, the cost of gas includes all of the items included in the gas cost deferral process. These include all of the commodity, demand, and upstream transportation charges the Company passes through to customers. The per therm rates shown on Exhibit 601, page 1, came directly from the most recent purchased gas adjustment (PGA) tracker filing that went into effect November 1, 2006. The pro forma revenue and gas costs included in this case are computed from the same PGA tracker rates.

<u>Results Analysis</u>

Q. Briefly describe what is shown on Exhibit 601 page 1 entitled "Result Summary".

A. The first three lines present the pro forma test year usage and customer statistics relevant to the study. The annual per customer and per therm results of all the cost items previously discussed are summarized to obtain total incremental costs, first on a per therm basis, then expanded to reflect the pro forma test year usage on line 14. The cost of gas is deducted to result in long-run incremental distribution costs. The distribution cost relationship of the service schedules to the total is then used to allocate current and proposed total margins to service schedules. These allocated margin levels represent distribution "costs", based on the LRIC results.

Finally, margin revenues from present and proposed rates are presented for comparison with the respective costs. The relative ratio of margin to cost is shown on lines 21 and 26 for present and proposed rates, respectively.

Q. What are the results of the Company's LRIC study?

A. The following table shows the margin-to-cost ratio at present and proposed rates for each rate schedule:

Table 1 Long Run Incremental Cost Study

Customer Class	Margin-to-Cost Present Rates	Margin-to-Cost Proposed Rates
Residential Service Schedule 410	1.00	1.00
General Service Schedule 420	0.89	0.89
Large General Service Schedule 424	2.62	2.62
Interruptible Sales Service Schedule 440	1.89	1.89
Seasonal Sales Service 444	3.27	3.28
Special Contracts Schedule 447	1.10	1.00
Transportation Service Schedule 456	1.11	1.11
Total Oregon Gas	1.00	1.00

The present margin-to-cost ratios indicate that general service (primarily commercial) customers on Schedule 420 are paying somewhat less than their cost of service, residential customers on Schedule 410 are at parity and the rates for all other customer groups are higher than their cost of service to varying degrees. The summary results of this study at the current cost level were provided to Mr. Hirschkorn as an input into development of the proposed rates. The margin-to-cost ratios at proposed rates show the results of the cost study after the proposed rate spread is applied. Since the proposed rate spread is an equal percent of margin, the margin-to-cost relationships essentially do not change.

Q. Did you perform any other analysis to corroborate the results produced from the LRIC study?

A. Yes. In order to gain a greater comfort level with the results, I ran the pro forma results of operations through the embedded cost of service model used in the Company's Washington and Idaho jurisdictions. The embedded model provides results in terms of the current rate of return produced by each customer group which is then compared to the overall rate of return.

Q. How did the embedded cost results compare to the LRIC results?

A. The results were similar with two key differences. In the embedded study, both residential Schedule 410 and general service Schedule 420 were under-earning whereas in the LRIC study residential Schedule 410 was at parity. Also, in the embedded study large general service Schedule 424 was only slightly over unity whereas in the LRIC study Schedule 424 is well above parity. The embedded results were also provided to Mr. Hirschkorn for his work on rate spread and rate design. The following table shows rate of return and return ratio results of this embedded cost study:

Table 2 Embedded Cost Study

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 410	6.50%	0.93
General Service Schedule 420	6.16%	0.89
Large General Service Schedule 424	7.49%	1.08
Interruptible Sales Service Schedule 440	16.45%	2.36
Seasonal Sales Service 444	14.08%	2.02
Special Contracts Schedule 447	18.94%	2.72
Transportation Service Schedule 456	13.41%	1.93
Total Oregon Gas	6.96%	1.00

Q. Please summarize your testimony regarding cost of service.

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 small general service customers on Schedule 420 to receive a somewhat larger percentage increase than other customer groups, and large general service and seasonal service customers on Schedules 424 and 444 to receive a smaller percentage increase than other customer groups.

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

A. Yes, it does.

	OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contrac Service SCH 447	Transportation Service SCH 456
CURRENT REVENUE	$ 127,414,088	$ 76,443,408	$ 39,490,218	$ 4,933,220	$ 3,423,452	$ 243,739	$ 476,072	$ 2,403,979
COST OF GAS	$ 95,324,935	$ 55,877,345	$ 32,083,199	$ 4,198,489	$ 2,955,152	$ 210,750	$ -	$ -
CURRENT MARGIN	$ 32,089,153	$ 20,566,063	$ 7,407,019	$ 734,731	$ 468,300	$ 32,989	$ 476,072	$ 2,403,979
% of Current Margin excl Sch 447	100.00%	65.06%	23.43%	2.32%	1.48%	0.10%		7.60%
Revenue Requirement incr (decr)	$2,975,000							
PROPOSED MARGIN (allocated by % of Curr Margin excl 447)	$ 35,064,153	$ 22,501,466	$ 8,104,068	$ 803,874	$ 512,370	$ 36,093	$ 476,072	$ 2,630,209
PROPOSED MARGIN REVENUE INCREASE	$ 2,975,000	$ 1,935,403	$ 697,049	$ 69,143	$ 44,070	$ 3,104	$ -	$ 226,230
INCREASE AS PERCENT OF CURRENT MARGIN	**9.27%**	**9.41%**	**9.41%**	**9.41%**	**9.41%**	**9.41%**	**0.00%**	**9.41%**
INCREASE AS PERCENT OF TOTAL PRESENT REVENUE	2.33%	2.53%	1.77%	1.40%	1.29%	1.27%	0.00%	9.41%
Current Revenue + Proposed Margin Rev Increase	$ 130,389,088	$ 78,378,811	$ 40,187,267	$ 5,002,363	$ 3,467,522	$ 246,843	$ 476,072	$ 2,630,209
Pro Forma Therm Usage	125,959,650	49,373,825	28,349,061	3,709,830	3,355,306	186,221	5,673,162	35,312,245
Seasonal Service Demand Rate - remove						-$0.21439		
Seasonal Demand Rev. reallocated to other Firm based on therm	$0	$24,206	$13,899	$1,819		($39,924)		
Change in ¢/therm		0.049	0.049	0.049		(21.439)		
PROPOSED REVENUE	$ 130,389,088	$ 78,403,017	$ 40,201,166	$ 5,004,182	$ 3,467,522	$ 206,920	$ 476,072	$ 2,630,209
INCREASE AS PERCENT OF TOTAL PRESENT REVENUE	2.33%	2.56%	1.80%	1.44%	1.29%	-15.11%	0.00%	9.41%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

TARA L. KNOX
Exhibit No. 601

Long-Run Incremental Cost

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2006

RESULT SUMMARY

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	TOTAL ANNUAL THERM DELIVERIES	125,959,650	49,373,825	28,349,061	3,709,830	3,355,306	186,221	5,673,162	35,312,245
2	2006 AVERAGE CUSTOMERS	92,418	81,424	10,808	98	40	8	4	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		606	2,623	37,855	83,883	23,278	1,418,291	980,896
	INCREMENTAL NON-COMMODITY COSTS PER CUSTOMER								
4	INVESTMENT COSTS		$348.28	$1,109.08	$4,187.95	$8,912.66	$1,828.94	$158,475.54	$87,121.90
5	GAS SUPPLY O&M		$3.04	$3.04	$3.04	$40.46	$3.04	$901.42	$901.42
6	CUSTOMER O&M		$20.85	$20.85	$20.85	$144.82	$20.85	$144.82	$144.82
7	TOTAL NON-COMMODITY COST PER CUSTOMER		$372.17	$1,132.97	$4,211.83	$9,097.94	$1,852.83	$159,521.79	$88,168.14
8	TOTAL NON-COMMODITY COST PER THERM		$0.61414	$0.43194	$0.11126	$0.10846	$0.07960	$0.11247	$0.08989
	INCREMENTAL COMMODITY COSTS PER THERM								
9	COMMODITY COST		$0.85727	$0.85727	$0.85727	$0.85727	$0.85727		
10	DEMAND COST		$0.20787	$0.20787	$0.20787	$0.00000	$0.20787		
11	AMORTIZATION RATE/THERM		$0.06658	$0.06658	$0.06658	$0.02347	$0.06658		
12	TOTAL COMMODITY COSTS PER THERM		$1.13172	$1.13172	$1.13172	$0.88074	$1.13172	$0.00000	$0.00000
13	TOTAL INCREMENTAL COSTS PER THERM		$1.74586	$1.56366	$1.24298	$0.98920	$1.21132	$0.11247	$0.08989
14	LONG-RUN INCREMENTAL COST	$ 142,496,092	$ 86,199,897	$ 44,328,163	$ 4,611,253	$ 3,319,068	$ 225,572	$ 638,087	$ 3,174,052
15	COST OF GAS	$ 95,324,935	$ 55,877,345	$ 32,083,199	$ 4,198,489	$ 2,955,152	$ 210,750	$ -	$ -
16	LONG-RUN INCREMENTAL DISTRIBUTION COST	$ 47,171,157	$ 30,322,552	$ 12,244,964	$ 412,764	$ 363,916	$ 14,822	$ 638,087	$ 3,174,052
	16A CLASS COST AS PERCENT OF TOTAL COST	100.00%	64.28%	25.96%	0.88%	0.77%	0.03%	1.35%	6.73%
17	CURRENT REVENUE	$ 127,414,088	$ 76,443,408	$ 39,490,218	$ 4,933,220	$ 3,423,452	$ 243,739	$ 476,072	$ 2,403,979
18	COST OF GAS	$ 95,324,935	$ 55,877,345	$ 32,083,199	$ 4,198,489	$ 2,955,152	$ 210,750	$ -	$ -
19	CURRENT MARGIN	$ 32,089,153	$ 20,566,063	$ 7,407,019	$ 734,731	$ 468,300	$ 32,989	$ 476,072	$ 2,403,979
	19A CURRENT MARGIN IN $ PER THERM	$ 0.254757	$ 0.416538	$ 0.261279	$ 0.198050	$ 0.139570	$ 0.177150	$ 0.083917	$ 0.068078
20	CURRENT COST (*Current Margin Allocated by Line 16A LRIDC*)	$ 32,089,153	$ 20,627,542	$ 8,329,889	$ 280,791	$ 247,561	$ 10,083	$ 434,072	$ 2,159,214
	20A CURRENT COST IN $ PER THERM	$ 0.254757	$ 0.417783	$ 0.293833	$ 0.075688	$ 0.073782	$ 0.054145	$ 0.076513	$ 0.061146
21	**CURRENT MARGIN TO COST RATIO (Line 19 ÷ Line 20)**	**1.00**	**1.00**	**0.89**	**2.62**	**1.89**	**3.27**	**1.10**	**1.11**
22	MARGIN LESS COST @ PRESENT RATES	$ -	$ (61,479)	$ (922,870)	$ 453,940	$ 220,739	$ 22,906	$ 42,000	$ 244,765
	22A MARGIN LESS COST @ PRESENT RATES IN $ PER THERM	$ -	$ (0.001)	$ (0.033)	$ 0.122	$ 0.066	$ 0.123	$ 0.007	$ 0.007
23	PROPOSED MARGIN REVENUE INCREASE	$ 2,975,000	$ 1,935,404	$ 697,049	$ 69,143	$ 44,070	$ 3,104	$ -	$ 226,230
24	PROPOSED MARGIN	$ 35,064,153	$ 22,501,467	$ 8,104,068	$ 803,874	$ 512,370	$ 36,093	$ 476,072	$ 2,630,209
	24A PROPOSED MARGIN IN $ PER THERM	$ 0.278376	$ 0.455737	$ 0.285867	$ 0.216688	$ 0.152704	$ 0.193818	$ 0.083917	$ 0.074484
25	PROPOSED COST (*Proposed Margin Allocated by Line 16A LRIDC*)	$ 35,064,153	$ 22,539,931	$ 9,102,157	$ 306,824	$ 270,513	$ 11,018	$ 474,315	$ 2,359,396
	25A PROPOSED COST IN $ PER THERM	$ 0.278376	$ 0.456516	$ 0.321074	$ 0.082706	$ 0.080622	$ 0.059165	$ 0.083607	$ 0.066815
26	**PROPOSED MARGIN TO COST RATIO (Line 24 ÷ Line 25)**	**1.00**	**1.00**	**0.89**	**2.62**	**1.89**	**3.28**	**1.00**	**1.11**
27	MARGIN LESS COST @ PROPOSED RATES	$ -	$ (38,464)	$ (998,089)	$ 497,050	$ 241,857	$ 25,075	$ 1,757	$ 270,813
	27A MARGIN LESS COST @ PROPOSED RATES IN $ PER THERM	$ -	$ (0.001)	$ (0.035)	$ 0.134	$ 0.072	$ 0.135	$ 0.000	$ 0.008

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2006

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	45 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	3/4"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	1/2" - 1.25"	1/2" - 1.25"
2	AVERAGE SERVICE COST		$ 336.97	$ 336.97	$ 368.45	$ 744.05	$ 368.45	$ 1,802.34	$ 1,701.51
3	LEVELIZED PLANT COST FACTOR		0.1969	0.1969	0.1969	0.1969	0.1969	0.1969	0.1969
4	ANNUAL REVENUE REQUIREMENT		$ 66.35	$ 66.35	$ 72.55	$ 146.50	$ 72.55	$ 354.88	$ 335.03
	METERS & REGULATORS	40 yr life							
5	METERS & REGULATORS		$ 85.05	$ 287.24	$ 2,243.37	$ 2,658.36	$ 2,707.09	$ 22,339.71	$ 8,686.37
6	LEVELIZED PLANT COST FACTOR		0.1977	0.1977	0.1977	0.1977	0.1977	0.1977	0.1977
7	ANNUAL REVENUE REQUIREMENT		$ 16.81	$ 56.79	$ 443.51	$ 525.56	$ 535.19	$ 4,416.56	$ 1,717.30
	MAIN INVESTMENT	65 yr life							
8	AVERAGE MAIN EXTENSION PER CUSTOMER		64	232	350	Variable	350	Estimated	Variable
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	4 "	2" - 6"	4 "	Bypass Cost	2" - 6"
10	AVERAGE COST PER FOOT 2006		14.48	14.48	16.06		16.06		
11	MAIN EXTENSION INVESTMENT		$ 926.72	$ 3,359.36	$ 5,621.00	$ 11,183.89	$ 5,621.00	$ 485,880.00	$ 28,427.92
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	22.28%	24.67%	46.87%	43.92%	0.00%	81.64%	38.73%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.149868	$ 0.672657	$ 0.607491	$ 0.319753	$ 0.341230	$ -	$ 0.183572	$ 0.386956
14	2006 AVERAGE THERMS PER CUSTOMER		606	2,623	37,855	83,883	23,278	1,418,291	980,896
15	CAPACITY MAIN INVESTMENT		$ 407.63	$ 1,593.45	$ 12,104.23	$ 28,623.35	$ -	$ 260,358.20	$ 379,563.44
16	INCR SAFETY MAIN INVESTMENT PER THERM		0.025643	$ 0.025643	$ 0.025643	$ 0.025643	$ 0.025643	$ 0.025643	$ 0.025643
17	2006 AVERAGE THERMS PER CUSTOMER		606	2,623	37,855	83,883	23,278	1,418,291	980,896
18	SAFETY MAIN INVESTMENT		$ 15.54	$ 67.26	$ 970.72	$ 2,151.01	$ 596.92	$ 36,369.24	$ 25,153.12
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 1,349.89	$ 5,020.07	$ 18,695.95	$ 41,958.26	$ 6,217.92	$ 782,607.44	$ 433,144.48
20	LEVELIZED PLANT COST FACTOR		0.1964	0.1964	0.1964	0.1964	0.1964	0.1964	0.1964
21	ANNUAL REVENUE REQUIREMENT		$ 265.12	$ 985.94	$ 3,671.88	$ 8,240.60	$ 1,221.20	$ 153,704.10	$ 85,069.58
22	**TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER**		**$ 348.28**	**$ 1,109.08**	**$ 4,187.95**	**$ 8,912.66**	**$ 1,828.94**	**$ 158,475.54**	**$ 87,121.90**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2006

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 MANAGEMENT (SCHEDULING)							
1	ANNUAL HOURS	0.01714	0.01714	0.01714	1.01714	0.01714	24.02532	24.02532
2	AVERAGE RATE PER HOUR	$ 37.42	$ 37.42	$ 37.42	$ 37.42	$ 37.42	$ 37.42	$ 37.42
3	LABOR COST	$ 0.64138	$ 0.64138	$ 0.64138	$ 38.06138	$ 0.64138	$ 899	$ 899
	GAS MANAGEMENT (PLANNING)							
4	ANNUAL HOURS	0.046483	0.046483	0.046483	0.046483	0.046483	0.046483	0.046483
5	AVERAGE RATE PER HOUR	$ 51.50	$ 51.50	$ 51.50	$ 51.50	$ 51.50	$ 51.50	$ 51.50
6	LABOR COST	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387
7	**TOTAL GAS SUPPLY O&M**	**$ 3.04**	**$ 3.04**	**$ 3.04**	**$ 40.46**	**$ 3.04**	**$ 901.42**	**$ 901.42**
	METER READING							
8	ANNUAL HOURS	0.04322	0.04322	0.04322	2.08333	0.04322	2.08333	2.08333
9	AVERAGE RATE PER HOUR	$ 21.12	$ 21.12	$ 21.12	$ 37.38	$ 21.12	$ 37.38	$ 37.38
10	LABOR COST	$ 0.91281	$ 0.91281	$ 0.91281	$ 77.87488	$ 0.91281	$ 77.87488	$ 77.87488
	CUSTOMER HANDBILLS							
11	ANNUAL HOURS	0.00000	0.00000	0.00000	2.22900	0.00000	2.22900	2.22900
12	AVERAGE RATE PER HOUR	$ -	$ -	$ -	$ 21.09	$ -	$ 21.09	$ 21.09
13	LABOR COST	$ -	$ -	$ -	$ 47.01	$ -	$ 47.01	$ 47.01
	BILLING							
14	ANNUAL POSTAGE PER CUST	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92
15	5 YR AVERAGE PER CUST	$ 17.02	$ 17.02	$ 17.02	$ 17.02	$ 17.02	$ 17.02	$ 17.02
16	BILLING COST	$ 19.94	$ 19.94	$ 19.94	$ 19.94	$ 19.94	$ 19.94	$ 19.94
17	**TOTAL CUSTOMER O&M**	**$ 20.85**	**$ 20.85**	**$ 20.85**	**$ 144.82**	**$ 20.85**	**$ 144.82**	**$ 144.82**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2006

RESULT SUMMARY

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	TOTAL ANNUAL THERM DELIVERIES	125,959,650	49,373,825	28,349,061	3,709,830	3,355,306	186,221	5,673,162	35,312,245
2	2006 AVERAGE CUSTOMERS	92,418	81,424	10,808	98	40	8	4	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		606	2,623	37,855	83,883	23,278	1,418,291	980,896
	INCREMENTAL NON-COMMODITY COSTS PER CUSTOMER								
4	INVESTMENT COSTS		$348.28	$1,109.08	$4,187.95	$8,912.66	$1,828.94	$158,475.54	$87,121.90
5	GAS SUPPLY O&M		$3.04	$3.04	$3.04	$40.46	$3.04	$901.42	$901.42
6	CUST0MER O&M		$20.85	$20.85	$20.85	$144.82	$20.85	$144.82	$144.82
7	TOTAL NON-COMMODITY COST PER CUSTOMER		$372.17	$1,132.97	$4,211.83	$9,097.94	$1,852.83	$159,521.79	$88,168.14
8	TOTAL NON-COMMODITY COST PER THERM		$0.61414	$0.43194	$0.11126	$0.10846	$0.07960	$0.11247	$0.08989
	INCREMENTAL COMMODITY COSTS PER THERM								
9	COMMODITY COST		$0.85727	$0.85727	$0.85727	$0.85727	$0.85727		
10	DEMAND COST		$0.20787	$0.20787	$0.20787	$0.00000	$0.20787		
11	AMORTIZATION RATE/THERM		$0.06658	$0.06658	$0.06658	$0.02347	$0.06658		
12	TOTAL COMMODITY COSTS PER THERM		$1.13172	$1.13172	$1.13172	$0.88074	$1.13172	$0.00000	$0.00000
13	TOTAL INCREMENTAL COSTS PER THERM		$1.74586	$1.56366	$1.24298	$0.98920	$1.21132	$0.11247	$0.08989
14	LONG-RUN INCREMENTAL COST	$ 142,496,092	$ 86,199,897	$ 44,328,163	$ 4,611,253	$ 3,319,068	$ 225,572	$ 638,087	$ 3,174,052
15	COST OF GAS	$ 95,324,935	$ 55,877,345	$ 32,083,199	$ 4,198,489	$ 2,955,152	$ 210,750	$ -	$ -
16	LONG-RUN INCREMENTAL DISTRIBUTION COST	$ 47,171,157	$ 30,322,552	$ 12,244,964	$ 412,764	$ 363,916	$ 14,822	$ 638,087	$ 3,174,052
	16A CLASS COST AS PERCENT OF TOTAL COST	100.00%	64.28%	25.96%	0.88%	0.77%	0.03%	1.35%	6.73%
17	CURRENT REVENUE	$ 127,414,088	$ 76,443,408	$ 39,490,218	$ 4,933,220	$ 3,423,452	$ 243,739	$ 476,072	$ 2,403,979
18	COST OF GAS	$ 95,324,935	$ 55,877,345	$ 32,083,199	$ 4,198,489	$ 2,955,152	$ 210,750	$ -	$ -
19	CURRENT MARGIN	$ 32,089,153	$ 20,566,063	$ 7,407,019	$ 734,731	$ 468,300	$ 32,989	$ 476,072	$ 2,403,979
	19A CURRENT MARGIN IN $ PER THERM	$ 0.254757	$ 0.416538	$ 0.261279	$ 0.198050	$ 0.139570	$ 0.177150	$ 0.083917	$ 0.068078
20	CURRENT COST (*Current Margin Allocated by Line 16A LRIDC*)	$ 32,089,153	$ 20,627,542	$ 8,329,889	$ 280,791	$ 247,561	$ 10,083	$ 434,072	$ 2,159,214
	20A CURRENT COST IN $ PER THERM	$ 0.254757	$ 0.417783	$ 0.293833	$ 0.075688	$ 0.073782	$ 0.054145	$ 0.076513	$ 0.061146
21	**CURRENT MARGIN TO COST RATIO (Line 19 ÷ Line 20)**	**1.00**	**1.00**	**0.89**	**2.62**	**1.89**	**3.27**	**1.10**	**1.11**
22	MARGIN LESS COST @ PRESENT RATES	$ -	$ (61,479)	$ (922,870)	$ 453,940	$ 220,739	$ 22,906	$ 42,000	$ 244,765
	22A MARGIN LESS COST @ PRESENT RATES IN $ PER THERM	$ -	$ (0.001)	$ (0.033)	$ 0.122	$ 0.066	$ 0.123	$ 0.007	$ 0.007
23	PROPOSED MARGIN REVENUE INCREASE	$ 2,975,000	$ 1,935,404	$ 697,049	$ 69,143	$ 44,070	$ 3,104	$ -	$ 226,230
24	PROPOSED MARGIN	$ 35,064,153	$ 22,501,467	$ 8,104,068	$ 803,874	$ 512,370	$ 36,093	$ 476,072	$ 2,630,209
	24A PROPOSED MARGIN IN $ PER THERM	$ 0.278376	$ 0.455737	$ 0.285867	$ 0.216688	$ 0.152704	$ 0.193818	$ 0.083917	$ 0.074484
25	PROPOSED COST (*Proposed Margin Allocated by Line 16A LRIDC*)	$ 35,064,153	$ 22,539,931	$ 9,102,157	$ 306,824	$ 270,513	$ 11,018	$ 474,315	$ 2,359,396
	25A PROPOSED COST IN $ PER THERM	$ 0.278376	$ 0.456516	$ 0.321074	$ 0.082706	$ 0.080622	$ 0.059165	$ 0.083607	$ 0.066815
26	**PROPOSED MARGIN TO COST RATIO (Line 24 ÷ Line 25)**	**1.00**	**1.00**	**0.89**	**2.62**	**1.89**	**3.28**	**1.00**	**1.11**
27	MARGIN LESS COST @ PROPOSED RATES	$ -	$ (38,464)	$ (998,089)	$ 497,050	$ 241,857	$ 25,075	$ 1,757	$ 270,813
	27A MARGIN LESS COST @ PROPOSED RATES IN $ PER THERM	$ -	$ (0.001)	$ (0.035)	$ 0.134	$ 0.072	$ 0.135	$ 0.000	$ 0.008

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2006

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	45 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	3/4"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	1/2" - 1.25"	1/2" - 1.25"
2	AVERAGE SERVICE COST		$ 336.97	$ 336.97	$ 368.45	$ 744.05	$ 368.45	$ 1,802.34	$ 1,701.51
3	LEVELIZED PLANT COST FACTOR		0.1969	0.1969	0.1969	0.1969	0.1969	0.1969	0.1969
4	ANNUAL REVENUE REQUIREMENT		$ 66.35	$ 66.35	$ 72.55	$ 146.50	$ 72.55	$ 354.88	$ 335.03
	METERS & REGULATORS	40 yr life							
5	METERS & REGULATORS		$ 85.05	$ 287.24	$ 2,243.37	$ 2,658.36	$ 2,707.09	$ 22,339.71	$ 8,686.37
6	LEVELIZED PLANT COST FACTOR		0.1977	0.1977	0.1977	0.1977	0.1977	0.1977	0.1977
7	ANNUAL REVENUE REQUIREMENT		$ 16.81	$ 56.79	$ 443.51	$ 525.56	$ 535.19	$ 4,416.56	$ 1,717.30
	MAIN INVESTMENT	65 yr life							
8	AVERAGE MAIN EXTENSION PER CUSTOMER		64	232	350	Variable	350	Estimated	Variable
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	4 "	2" - 6"	4 "	Bypass Cost	2" - 6"
10	AVERAGE COST PER FOOT 2006		14.48	14.48	16.06		16.06		
11	MAIN EXTENSION INVESTMENT		$ 926.72	$ 3,359.36	$ 5,621.00	$ 11,183.89	$ 5,621.00	$ 485,880.00	$ 28,427.92
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	22.28%	24.67%	46.87%	43.92%	0.00%	81.64%	38.73%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.149868	$ 0.672657	$ 0.607491	$ 0.319753	$ 0.341230	$ -	$ 0.183572	$ 0.386956
14	2006 AVERAGE THERMS PER CUSTOMER		606	2,623	37,855	83,883	23,278	1,418,291	980,896
15	CAPACITY MAIN INVESTMENT		$ 407.63	$ 1,593.45	$ 12,104.23	$ 28,623.35	$ -	$ 260,358.20	$ 379,563.44
16	INCR SAFETY MAIN INVESTMENT PER THERM		0.025643	$ 0.025643	$ 0.025643	$ 0.025643	$ 0.025643	$ 0.025643	$ 0.025643
17	2006 AVERAGE THERMS PER CUSTOMER		606	2,623	37,855	83,883	23,278	1,418,291	980,896
18	SAFETY MAIN INVESTMENT		$ 15.54	$ 67.26	$ 970.72	$ 2,151.01	$ 596.92	$ 36,369.24	$ 25,153.12
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 1,349.89	$ 5,020.07	$ 18,695.95	$ 41,958.26	$ 6,217.92	$ 782,607.44	$ 433,144.48
20	LEVELIZED PLANT COST FACTOR		0.1964	0.1964	0.1964	0.1964	0.1964	0.1964	0.1964
21	ANNUAL REVENUE REQUIREMENT		$ 265.12	$ 985.94	$ 3,671.88	$ 8,240.60	$ 1,221.20	$ 153,704.10	$ 85,069.58
22	**TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER**		**$ 348.28**	**$ 1,109.08**	**$ 4,187.95**	**$ 8,912.66**	**$ 1,828.94**	**$ 158,475.54**	**$ 87,121.90**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2006

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 MANAGEMENT (SCHEDULING)							
1	ANNUAL HOURS	0.01714	0.01714	0.01714	1.01714	0.01714	24.02532	24.02532
2	AVERAGE RATE PER HOUR	$ 37.42	$ 37.42	$ 37.42	$ 37.42	$ 37.42	$ 37.42	$ 37.42
3	LABOR COST	$ 0.64138	$ 0.64138	$ 0.64138	$ 38.06138	$ 0.64138	$ 899	$ 899
	GAS MANAGEMENT (PLANNING)							
4	ANNUAL HOURS	0.046483	0.046483	0.046483	0.046483	0.046483	0.046483	0.046483
5	AVERAGE RATE PER HOUR	$ 51.50	$ 51.50	$ 51.50	$ 51.50	$ 51.50	$ 51.50	$ 51.50
6	LABOR COST	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387	$ 2.39387
7	**TOTAL GAS SUPPLY O&M**	**$ 3.04**	**$ 3.04**	**$ 3.04**	**$ 40.46**	**$ 3.04**	**$ 901.42**	**$ 901.42**
	METER READING							
8	ANNUAL HOURS	0.04322	0.04322	0.04322	2.08333	0.04322	2.08333	2.08333
9	AVERAGE RATE PER HOUR	$ 21.12	$ 21.12	$ 21.12	$ 37.38	$ 21.12	$ 37.38	$ 37.38
10	LABOR COST	$ 0.91281	$ 0.91281	$ 0.91281	$ 77.87488	$ 0.91281	$ 77.87488	$ 77.87488
	CUSTOMER HANDBILLS							
11	ANNUAL HOURS	0.00000	0.00000	0.00000	2.22900	0.00000	2.22900	2.22900
12	AVERAGE RATE PER HOUR	$ -	$ -	$ -	$ 21.09	$ -	$ 21.09	$ 21.09
13	LABOR COST	$ -	$ -	$ -	$ 47.01	$ -	$ 47.01	$ 47.01
	BILLING							
14	ANNUAL POSTAGE PER CUST	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92
15	5 YR AVERAGE PER CUST	$ 17.02	$ 17.02	$ 17.02	$ 17.02	$ 17.02	$ 17.02	$ 17.02
16	BILLING COST	$ 19.94	$ 19.94	$ 19.94	$ 19.94	$ 19.94	$ 19.94	$ 19.94
17	**TOTAL CUSTOMER O&M**	**$ 20.85**	**$ 20.85**	**$ 20.85**	**$ 144.82**	**$ 20.85**	**$ 144.82**	**$ 144.82**

AVISTA/601
Knox/Page 3 of 3

Exhibit 700
Hirschkorn

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

DIRECT TESTIMONY OF BRIAN J. HIRSCHKORN
REPRESENTING THE AVISTA CORPORATION

Rate Design and Rate Spread

INTRODUCTION

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

A. My name is Brian J. Hirschkorn and my business address is East 1411 Mission Avenue, Spokane, Washington. My present position is Manager of Retail Pricing.

Q. Would you describe your responsibilities in your position as Manager of Retail Pricing?

A. My primary areas of responsibility include electric and gas rate design, special contract pricing, customer usage and revenue analysis, and tariff administration.

Q. Would you briefly describe your educational background?

A. I graduated from Washington State University in 1978 with Bachelor degrees in Business Administration and Accounting.

Q. Have you previously testified before other state commissions?

A. Yes. I have testified before the Washington & Idaho Commissions in numerous rate proceedings as a revenue and rate design witness.

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

A. My testimony in this proceeding will cover the spread of the proposed annual revenue increase among the Company's gas service schedules as well as the application of the increase to the rates within each of the schedules. I will also discuss the revenue normalization adjustment, as well as recent changes in customer natural gas usage.

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

A. Yes. I am sponsoring Exhibit Nos. 701, 702, and 703, which were prepared under my supervision and direction.

Q. Would you please explain what is contained in Exhibit No. 701?

A. Exhibit No. 701 is a copy of the Company's present rates governing natural gas service in the State of Oregon, which are on file with this Commission as a part of the Company's tariff, PUC OR. No. 4.

Q. Turning now to Exhibit No. 702, would you please state what is contained in that Exhibit?

A. Exhibit No. 702 contains the proposed natural gas rates and schedules which are being filed with the Commission as a part of our revised tariff, PUC OR. No. 4.

Q. Could you please explain what is contained in Exhibit No. 703?

A. Exhibit No. 703 contains information regarding the proposed rate spread and rate design of the proposed annual revenue increase of $2,975,000. Page 1 shows the proposed revenue and percentage increase by service schedule. Page 2 shows the present billing 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.

REVENUE NORMALIZATION

Q. Would you please describe the "Revenue Normalization Adjustment" which you have referred to?

A. The Revenue Normalization Adjustment represents the difference between the Company's actual recorded retail revenues during the 2006 test period and revenue adjusted for normal weather and other pro forma adjustments. The total revenue normalization adjustment decreases Oregon net operating income by $411,000, as shown in column PF 1 on Page 6 of Exhibit No. 501, sponsored by Company witness Ms. Andrews. The adjustment consists of four primary components: 1) re-pricing customer usage (adjusted for known and measurable changes) at present tariff rates in effect; 2) adjusting customer loads and revenue to a calendar-year basis by estimating unbilled revenue; 3) weather normalizing customer usage and revenue; and 4) restating gas supply costs at the rates approved in the Company's last Purchased Gas Adjustment (PGA) filing.

Q. You stated that the first component of the Revenue Normalization Adjustment is to re-price test period customer usage at present rates in effect. You also stated that customer usage is adjusted for known and measurable changes. Have you made any adjustments to actual customer usage?

A. Yes, but only for a few of the large customers that the Company serves. As part of this filing, I examined the 2006 usage for all customers served under Interruptible Service Schedule 440, Transportation Service Schedule 456 and Special Contract Schedule 447. Adjustments were made for customers that switched service schedules since the beginning of 2006, or have significantly changed their gas consumption as compared to their usage during 2006. Adjustments were made to reflect a full year of service to these customers based on their current service schedule and/or natural gas usage. The net revenue effect of these adjustments is not material.

Q. You mentioned that the Company estimates "unbilled" revenue as part of the Revenue Normalization Adjustment. Why is this necessary?

A. The unbilled revenue estimate serves to adjust customer usage billed during the test year to estimated usage on calendar year basis. Because a substantial portion of customer usage billed in January is actually consumed in December, the Company estimates this usage based on meter-reading schedules and actual weather (degree-day) information. The adjustment on each end of the test year (January and December) results in a net unbilled adjustment. The weather normalization adjustment, as discussed by Company witness Ms. Knox, is determined on a calendar-year basis, and, together with the unbilled revenue adjustment, results in weather-normalized usage on a calendar year basis.

Q. Could you please summarize the process used in deriving the Revenue Normalization Adjustment?

A. Yes. First, actual customer usage for the test period is adjusted for known and measurable large customer changes. Then the usage adjustments for unbilled revenue and weather normalization are added to arrive at pro forma test period usage by schedule. The pro forma test period usage, together with the number of customers, is multiplied by present rates to determine pro forma revenue. Actual revenue for the test period is then subtracted from pro forma revenue resulting in the revenue adjustment.

Q. Does the Company make a similar adjustment to actual gas costs during the test period?

A. Yes. The Company's present retail rates include gas costs approved by the Commission in the Company's last PGA filing, effective November 1, 2006. Actual 2006 gas costs must be adjusted to reflect the gas costs included in present rates. Therefore, the current PGA rates (forward-looking gas costs and amortization) are multiplied by the 2006 pro forma usage resulting in pro forma gas costs. Actual gas costs are then subtracted from the pro forma gas costs to arrive at the corresponding gas cost adjustment.

Q. Is the Company proposing any changes to the present allocation of gas costs by rate schedule used in its PGA filings?

A. Yes, but only one. The Company proposes to remove firm pipeline transportation costs from the rates for Seasonal Service Schedule 444. Under the present tariff, Schedule 444 customers are precluded from taking service between November 30^{th} and March 1^{st}, the period during which the system peak occurs. As firm pipeline transportation is contracted for by the Company to meet peak demand during this period, these customers should not bear any of these costs. There are only eight customers served under this Schedule, nearly all of which are mint farmers, with a total annual usage of 186,000 therms. This proposed change would reallocate $40,000 in demand costs to the other firm service rate schedules (410, 420 and 424), and would be spread based on normalized test year volumes. The result of this cost reallocation results in a decrease of 21.439 cents per therm in the rate under Seasonal Schedule 444 and an increase of 0.049 cents per therm in the rates of schedules 410, 420, and 424.

CHANGES IN CUSTOMER USAGE

Q. Has the Company seen a decline in usage per customer in recent years?

A. Yes, it has. Average use per customer declined by 5.3% for residential customers and by 1.4% for commercial customers from 2002 to 2006. On a compound average annual basis, the decrease is 1.3% for residential customers and 0.4% for commercial customers.

Q. What is the impact of decreased use per customer on the Company?

A. While the decrease in usage per customer is not as pronounced as it was prior to 2002 , the declining trend continues to erode the Company's recovery of fixed costs. The present annual lost margin associated with the decline in usage per customer since 2002 amounts to $766,000 for residential customers and $81,000 for commercial customers over a four-year period (2002 to 2006).

Q. Has the Company seen a decrease in natural gas usage by its industrial customers?

A. Yes, it has. Gas prices have increased significantly since 2002 and a number of industrial customers have significantly reduced load either because of fuel switching or market conditions. Total Transportation Schedules 456 and 447 usage is down 23.8%; however, because of annual minimum bill requirements for special contract Schedule 447 customers, loss of margin has been mitigated.

PROPOSED RATE DESIGN AND RATE SPREAD

Q. Would you please describe the Company's present rate schedules and the types of gas service offered under each?

A. Yes. The table on the following page shows the type of customer and the average number of customers served during 2006 under each of the Company's Oregon natural gas schedules.

Schedule	Type of Customer	No. of Customers
Residential Sch. 410	Residential	81,400
General Sch. 420	Commercial	10,800
Lge. General Sch. 424	Lge. Comm. & Industrial	98
Interruptible Sch. 440	Lge. Comm. & Industrial	21
Seasonal Sch. 444	Non-winter Use	8
Transportation Sch. 456	Lge. Industrial	36
Sp. Contract Sch. 447	Lge. Industrial Transportation	5

Q. How does the Company propose to spread the proposed revenue increase of $2,975,000, or 2.3%, among its various service schedules?

A. The Company proposes to spread the revenue increase on a uniform percentage increase applied to the present margin under each of the schedules (excluding Special Contract Schedule 447). The following table shows the resulting percentage increase in present revenue for each of the service schedules.

Schedule	Type of Customer	% Increase
Residential Sch. 410	Residential	2.6%
General Sch. 420	Commercial	1.8%
Lge. General Sch. 424	Lge. Comm. & Industrial	1.4%
Interruptible Sch. 440	Lge. Comm. & Industrial	1.3%
Seasonal Sch. 444	Non-winter Use	-15.1%
Transportation Sch. 456	Lge. Industrial	9.4%

This information, as well as the related revenue information, is also provided on Page 1 of Exhibit No. 703. Two items of note in the above table: 1) the decrease for Schedule 444 results from the elimination of pipeline firm transportation costs discussed earlier, and 2) the rates and revenue for Schedule 456 do not include gas costs or pipeline transportation costs, as the Company provides only distribution service to these customers.

Q. Did the Company examine the results of the cost of service study prepared by Ms. Knox?

A. Yes. Ms. Knox prepared a long-run incremental cost study as well as an embedded cost of service study. Upon examining the results of these studies, the Company felt that the results were not conclusive enough to propose a rate spread that substantially deviated from a uniform percent of margin increase.

Q. Turning now to the proposed changes to the rates <u>within</u> the various service schedules, could you please describe what is shown on Page 2 of Exhibit No. 703?

A. Page 2 of Exhibit No. 703 shows the present rates for each of the various schedules, the proposed increases to those rates, and the resulting proposed rates.

Q. Could you please describe the proposed changes in the rates for Residential Schedule 410 that result in the overall increase of 2.6% for that Schedule?

A. As shown on Page 24 of Exhibit No. 703, the Company is proposing an increase in the present monthly customer charge of $0.50 per month, from $5.00 to $5.50. The present charge per therm is increased by 2.979 cents per therm, from 144.931 cents to 147.910 cents. The additional revenue resulting from these increases yields the proposed overall increase of 2.6% in the revenue from customers served under the Schedule.

Q. Why is the Company proposing an increase in the monthly customer charge?

A. The monthly customer charge should recover a reasonable level of Company fixed costs that are necessary to serve those customers. In measuring the adequacy of the monthly customer charge, the Company typically examines costs associated with meters, meter reading, billing and billing assistance (call center), and distribution services, which are shown on Page 3 of Exhibit No. 703. The distribution service is typically the cost of the gas service line from the street in front of the customer's premise to the meter. These costs, as well as other fixed costs, are incurred regardless of customer usage. While the Company has a substantial amount of other fixed costs required to provide natural gas service, these costs represent the minimum level of fixed costs required to provide service to a customer. As shown on line 5, the Company's average monthly cost associated with providing these services to a residential customer is $6.46 per month.

Q. What is the change in the average residential customer's bill as a result of these proposed changes?

A. Based on an average usage level of 51 therms per month, the average residential bill would increase $2.02 per month, or 2.6%, from $78.91 to $80.93.

Q. Could you please describe the changes you propose to the rates of General Service Schedule 420?

A. Yes. As shown on Page 2 of Exhibit No. 703, the present rates for service under Schedule 420 consist of a $6.00 per month customer charge and a usage charge of 136.555 cents per therm. The Company is proposing an increase in the customer charge of $0.50 per month, from $6.00 to $6.50, and an increase of 2.279 cents per therm in the usage charge. These changes result in the overall proposed increase of 1.8% in the revenue for the Schedule.

Q. Regarding the proposed increase in the customer charge, did you prepare an analysis, similar to that provided for residential customers, of the fixed costs associated with providing service to customers served under this Schedule?

A. Yes. Line 5, column (g) on page 3 of Exhibit No. 703, shows the average monthly cost associated with meters, meter reading, billing and service lines for these customers. As shown, these monthly costs total $10.33; the proposed customer charge of $6.50 per month represents only about 63% of these costs.

Q. Could you 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, i.e., who have a relatively high load-factor compared to other firm service customers. The Company is proposing an increase of 1.913 cents per therm to the present usage rate under the Schedule and no change to the present monthly customer charge of $65.00 per month, resulting in an overall increase of 1.4% in the revenue under the Schedule.

Seasonal Service Schedule 444 is for customers who use no natural gas during December, January and February. As previously discussed, there are presently only eight customers 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 <u>decrease</u> in the per therm charge under the Schedule of 19.772 cents, resulting from the decrease of 21.439 cents per therm for the removal of pipeline demand charges, and an increase of 1.667 cents per therm reflecting the proposed margin increase.

Q. Could you 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 do not pay for firm pipeline transportation through their rates, as they do not create peak service requirements. The Company is proposing that the rate for service under Schedule 440 be increased by 1.313 cents per therm, resulting in a proposed revenue increase of 1.3%.

Q. Could you please describe the proposed changes to the present rates for Transportation Service Schedule 456?

A. Yes. 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 2 of Exhibit No. 703, the present rates under the Schedule consist of a monthly customer charge of $187.50 and a five-block rate structure with declining rates for higher usage. The Company is proposing a $12.50 per month increase in the customer charge, to $200.00, and a uniform percentage increase to all rate blocks in the Schedule.

Q. Is the Company proposing any other changes to its natural gas service tariffs in this filing?

A. Yes, just one. Under the present tariff for Schedule 440 there is an annual minimum charge based on an annual minimum usage requirement of 225,000 therms. Over time, a number of customer served under the Schedule have reduced their usage to less than 225,000 therms per year. Customers served under the Schedule are required to have alternate fuel capability and have the ability to reduce their gas usage on short notice. The Company wants to discourage existing interruptible customers from switching to a firm service schedule merely because of the size of the present annual minimum charge under the Schedule, as the interruptibility of these customers help ensure service to existing firm customers. The Company proposes to reduce the annual minimum usage requirement to 50,000 therms per year, which is less than the present usage of all customers served under the Schedule, together with a corresponding change in the annual minimum charge.

Q. Does that conclude your pre-file, direct testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

BRIAN J. HIRSCHKORN
Exhibit No. 701

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:	$5.00	
Commodity Charge Per Therm:	$1.44931	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. A reconnection charge shall be made for restoration of service where service has been turned off for seasonal turnoff, or for other reasons arising through the action or for the convenience of the customer. (See Rule No. 20)

2. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.

3. The above Commodity Charge includes a $.00438 per therm for the Residential Low Income Rate Assistance Program, as set forth under Schedule 493.

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:	$6.00	
Commodity Charge Per Therm:	$1.36555	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. A reconnection charge shall be made for restoration of service when service has been turned off for reasons arising through action of or for the convenience of the customer. (See Rule No. 20)

2. Service for the sole purpose of supplying a fireplace, log lighter, gas log, barbecue or any multiple or combination thereof, will be rendered only under this schedule. Where service for such purpose is requested, an advance-in-aid of construction in the amount of the Company's estimated total additional investment in the facilities required to provide such service shall be made prior to the commencement of construction. If the advance is for facilities to serve more than one customer location, an appropriate portion thereof will be assigned to each customer location. The advance will be refunded by the Company to the person or entity who made the advance, or his or its designee, upon the expiration of 36 months of billings for consumption under this schedule (which may or may not be continuous),

(continued)

SCHEDULE 420 (continued)

GENERAL NATURAL GAS SERVICE - OREGON

or upon the transfer of service at the customer location to a different schedule. Any advance or portion thereof not refunded within five years from the inception of service shall be retained by the Company.

3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.

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:	\$65.00	
Commodity Charge Per Therm:	\$1.30913	(I)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

SPECIAL CONDITIONS:

1. This service is available only where adequate capacity exists in the Company's system.

2. As a condition precedent to service under this schedule an executed Agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.

3. The term of service shall be for a period of one year when service is first rendered and year by year thereafter, continuing until cancelled by ninety days prior written notice given by either party to the other.

(continued)

SCHEDULE 424 (continued)

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

4. The applicability clause shown above will not apply to any customer taking service on or before August 1, 1990.

5. Service under this schedule is subject to adjustments as specified under Schedule No. 451 as well as any other applicable adjustments approved by the Public Utility Commission.

6. Rates contained in this schedule will be used to determine balancing penalties and the standby sales service commodity price for Schedule No. 455.

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 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	
Commodity Charge Per Therm:	$1.02031	(I)

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 225,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 225,000 therms multiplied by 11.285 cents per therm.

SPECIAL CONDITIONS:

1. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.
2. 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

(continued)

SCHEDULE 440 (continued)

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

3. As a condition precedent to service under this schedule, an executed agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.

4. The term of service shall be for a period of one year when service is first rendered and year by year thereafter, continuing until cancelled by ninety days prior written notice given by either party to the other.

5. No customer shall be entitled to service under this rate schedule unless adequate standby equipment and alternative fuel are provided by the customer and are ready at all times for immediate operation in the event that natural gas is interrupted or curtailed in whole or in part.

6. The Company shall give the customer as much notice of an impending curtailment as is reasonably possible under the circumstances at the time. The Company will not be liable for damages occasioned by interruption or discontinuance of service provided under this schedule.

7. In the event of curtailment, customers under this schedule will be curtailed in accordance with Rule No. 14, Continuity Of Service. Interruptible customers are the first to be curtailed.

8. Insofar as operationally practicable, curtailment to each customer receiving service under this schedule shall be pro rata. Proration shall be based on equalization of the number of hours of curtailment for each customer in each heating season (July 1 through June 30).

9. In the event that it is necessary to discontinue service, the monthly minimum charge will be prorated on the basis of the ratio of the number of days on which service was available to the number of days in the billing period. For this purpose

(continued)

SCHEDULE 440 (continued)

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

service will be considered available if curtailed by the Company less than eight hours in any particular day.

10. Service under this schedule is subject to adjustments as specified under Schedule No. 452 as well as any other applicable adjustments approved by the Public Utility Commission.

11. Rates contained in this schedule will be used to determine balancing penalties and the standby sales service commodity price for Schedule No. 456.

12. The applicability clause shown above will not apply to any customer taking service on or before August 1, 1990.

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:	$1.30887	(I)
Minimum Charge: $8,620.20 per season.		(I)

SPECIAL CONDITIONS:

1. A contract will be required for a period of one (1) year when service is first rendered and year by year thereafter. Service will be subject to termination at the end of any contract year in the event the supply of gas may become limited to other firm gas customers.

2. The Company, when operating its propane-air peak shaving facilities, falls under the jurisdiction of the Federal Energy Agency with respect to the Company's allocation of propane for such purposes as directed

(continued)

SCHEDULE 444 (continued)

SEASONAL NATURAL GAS SERVICE - OREGON

in Chapter II, Title 10, CFR, Part 211, or similar orders which may be subsequently issued. In the event that customer has an alternate fuel capability, the Company shall discontinue service to customer and customer shall convert immediately to alternate fuel usage during those times the Company's peak shaving facilities are in operation, in accordance with these orders.

3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.

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:	$187.50
Volumetric Charge Per Therm:	
First 10,000	$.12900
Next 20,000	$.07757
Next 20,000	$.06373
Next 200,000	$.04984
All Additional	$.02520

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

Gross Revenue Fee Reimbursement:
The total of all charges invoiced by the Company shall be subject to a Gross Revenue Fee reimbursement charge of 2.2545 percent to cover (R)
governmental fees and levies imposed upon the Company, as those fees and levies may be in effect from time to time.

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 456 (continued)

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

SPECIAL CONDITIONS:

1. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.

2. 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.

3. As a condition precedent to service under this schedule, an executed agreement with the Company is required specifying transportation quantity requirements and other terms and conditions as hereinafter provided.

4. The term of service shall be for a period of one year when service is first rendered and year by year thereafter, continuing until cancelled by ninety days prior written notice given by either party to the other.

5. All terms and conditions of Rule No. 21 apply to the transportation of customer-owned gas under this schedule.

6. No customer shall be entitled to service under this rate schedule until the customer complies with the standby facilities requirements for interruptible transportation service customers as described in Rule No. 21.

7. It is the intent of the Company and the customer that the quantity of customer-owned gas delivered to the customer on any day approximately equal the quantity of gas received by the Company for transportation to the customer. Imbalances in deliveries will be handled with a balancing account. Rule No. 21 describes how the balancing account will work.

(continued)

SCHEDULE 456 (continued)

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

8. Customers receiving service under this schedule have the option to procure the standby sales service offered by the Company under Schedule No. 459.

9. Rates contained in Schedule No. 440 will be used to determine balancing penalties and the standby sales service commodity price for customers procuring service under this schedule.

10. The Company shall give the customer as much notice of an impending curtailment as is reasonably possible under the circumstances at the time. The Company will not be liable for damages occasioned by interruption or discontinuance of service provided under this schedule.

11. In the event of capacity curtailment, customers under this schedule will be curtailed in accordance with Rule No. 14, Continuity Of Service. Interruptible customers are the first to be curtailed.

12. In the event of supply shortages, customers under this schedule shall receive their transport volumes except during an emergency requiring the use of the customer's gas to serve essential human needs. Appropriation of customer-owned gas during supply shortages is more fully described in Rule No. 21.

13. Insofar as operationally practicable, curtailment to each customer receiving service under this schedule shall be pro rata. Proration shall be based on equalization of the number of hours of curtailment for each customer in each heating season (July 1 through June 30).

14. In the event that it is necessary to discontinue service, the monthly minimum charge will be prorated on the basis of the ratio of the number of days on which service was available to the number of days in the billing period. For this purpose service will be considered available if curtailed by the Company less than eight hours in any particular day.

15. Service under this schedule is subject to the general rules and regulations contained in this tariff and to those prescribed by regulatory authorities.

(continued)

Advice No. 99-3-G
Issued April 15, 1999

Effective For Service On & After
May 19, 1999

Issued by Avista Utilities
By Thomas D. Dukich ,Manager, Rates & Tariff Administration

SCHEDULE 456 (continued)

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

16. Upon mutual agreement between Company and customer, a customer whose business is of a seasonal nature may limit transportation service to their seasonal operating period.

17. The Company is not obligated to maintain long-term gas supplies for transportation customers. Therefore, if a customer provided service under this schedule desires to change to a sales service schedule, the customer shall be liable for any additional charges associated with incremental gas supply costs, if they are higher than average supply costs.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

BRIAN J. HIRSCHKORN
Exhibit No. 702

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:	\$5.50	(I)
Commodity Charge Per Therm:	\$1.47910	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. A reconnection charge shall be made for restoration of service where service has been turned off for seasonal turnoff, or for other reasons arising through the action or for the convenience of the customer. (See Rule No. 20)
2. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.
3. The above Commodity Charge includes a \$.00438 per therm for the Residential Low Income Rate Assistance Program, as set forth under Schedule 493.

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:	$6.50	(I)
Commodity Charge Per Therm:	$1.38834	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

SPECIAL CONDITIONS:

1. A reconnection charge shall be made for restoration of service when service has been turned off for reasons arising through action of or for the convenience of the customer. (See Rule No. 20)

2. Service for the sole purpose of supplying a fireplace, log lighter, gas log, barbecue or any multiple or combination thereof, will be rendered only under this schedule. Where service for such purpose is requested, an advance-in-aid of construction in the amount of the Company's estimated total additional investment in the facilities required to provide such service shall be made prior to the commencement of construction. If the advance is for facilities to serve more than one customer location, an appropriate portion thereof will be assigned to each customer location. The advance will be refunded by the Company to the person or entity who made the advance, or his or its designee, upon the expiration of 36 months of billings for consumption under this schedule (which may or may not be continuous),

(continued)

SCHEDULE 420 (continued)

GENERAL NATURAL GAS SERVICE - OREGON

or upon the transfer of service at the customer location to a different schedule. Any advance or portion thereof not refunded within five years from the inception of service shall be retained by the Company.

3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.

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:	$65.00	
Commodity Charge Per Therm:	$1.32826	(I)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

SPECIAL CONDITIONS:

1. This service is available only where adequate capacity exists in the Company's system.
2. As a condition precedent to service under this schedule an executed Agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.
3. The term of service shall be for a period of one year when service is first rendered and year by year thereafter, continuing until cancelled by ninety days prior written notice given by either party to the other.

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 424 (continued)

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

4. The applicability clause shown above will not apply to any customer taking service on or before August 1, 1990.

5. Service under this schedule is subject to adjustments as specified under Schedule No. 451 as well as any other applicable adjustments approved by the Public Utility Commission.

6. Rates contained in this schedule will be used to determine balancing penalties and the standby sales service commodity price for Schedule No. 455.

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. (C)

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:	$1.03344	(I)

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 (C)
Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 15.270 (C)(I)
cents per therm.

SPECIAL CONDITIONS:

1. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.

2. 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

(continued)

SCHEDULE 440 (continued)

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

3. As a condition precedent to service under this schedule, an executed agreement with the Company is required specifying quantity requirements and other terms and conditions as hereinafter provided.

4. The term of service shall be for a period of one year when service is first rendered and year by year thereafter, continuing until cancelled by ninety days prior written notice given by either party to the other.

5. No customer shall be entitled to service under this rate schedule unless adequate standby equipment and alternative fuel are provided by the customer and are ready at all times for immediate operation in the event that natural gas is interrupted or curtailed in whole or in part.

6. The Company shall give the customer as much notice of an impending curtailment as is reasonably possible under the circumstances at the time. The Company will not be liable for damages occasioned by interruption or discontinuance of service provided under this schedule.

7. In the event of curtailment, customers under this schedule will be curtailed in accordance with Rule No. 14, Continuity Of Service. Interruptible customers are the first to be curtailed.

8. Insofar as operationally practicable, curtailment to each customer receiving service under this schedule shall be pro rata. Proration shall be based on equalization of the number of hours of curtailment for each customer in each heating season (July 1 through June 30).

9. In the event that it is necessary to discontinue service, the monthly minimum charge will be prorated on the basis of the ratio of the number of days on which service was available to the number of days in the billing period. For this purpose

(continued)

SCHEDULE 440 (continued)

INTERRUPTIBLE NATURAL GAS SERVICE
FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

service will be considered available if curtailed by the Company less than eight hours in any particular day.

10. Service under this schedule is subject to adjustments as specified under Schedule No. 452 as well as any other applicable adjustments approved by the Public Utility Commission.

11. Rates contained in this schedule will be used to determine balancing penalties and the standby sales service commodity price for Schedule No. 456.

12. The applicability clause shown above will not apply to any customer taking service on or before August 1, 1990.

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:	$1.11115	(R)

Minimum Charge:
$8,620.20 per season.

SPECIAL CONDITIONS:

1. A contract will be required for a period of one (1) year when service is first rendered and year by year thereafter. Service will be subject to termination at the end of any contract year in the event the supply of gas may become limited to other firm gas customers.

2. The Company, when operating its propane-air peak shaving facilities, falls under the jurisdiction of the Federal Energy Agency with respect to the Company's allocation of propane for such purposes as directed

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 444 (continued)

SEASONAL NATURAL GAS SERVICE - OREGON

in Chapter II, Title 10, CFR, Part 211, or similar orders which may be subsequently issued. In the event that customer has an alternate fuel capability, the Company shall discontinue service to customer and customer shall convert immediately to alternate fuel usage during those times the Company's peak shaving facilities are in operation, in accordance with these orders.

3. Service under this schedule is subject to adjustments as specified under Schedule 451 as well as any other applicable adjustments approved by the Public Utility Commission.

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:	$200.00	(I)
Volumetric Charge Per Therm:		
First 10,000	$.14126	(I)
Next 20,000	$.08494	(I)
Next 20,000	$.06979	(I)
Next 200,000	$.05458	(I)
All Additional	$.02760	(I)

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

Gross Revenue Fee Reimbursement:

The total of all charges invoiced by the Company shall be subject to a Gross Revenue Fee reimbursement charge of 2.2825 percent to cover governmental fees and levies imposed upon the Company, as those fees and levies may be in effect from time to time. (I)

(continued)

SCHEDULE 456 (continued)

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

SPECIAL CONDITIONS:

1. This service is available only where capacity in excess of firm sales and firm transportation requirements exists in the Company's system.

2. 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.

3. As a condition precedent to service under this schedule, an executed agreement with the Company is required specifying transportation quantity requirements and other terms and conditions as hereinafter provided.

4. The term of service shall be for a period of one year when service is first rendered and year by year thereafter, continuing until cancelled by ninety days prior written notice given by either party to the other.

5. All terms and conditions of Rule No. 21 apply to the transportation of customer-owned gas under this schedule.

6. No customer shall be entitled to service under this rate schedule until the customer complies with the standby facilities requirements for interruptible transportation service customers as described in Rule No. 21.

7. It is the intent of the Company and the customer that the quantity of customer-owned gas delivered to the customer on any day approximately equal the quantity of gas received by the Company for transportation to the customer. Imbalances in deliveries will be handled with a balancing account. Rule No. 21 describes how the balancing account will work.

(continued)

SCHEDULE 456 (continued)

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

8. Customers receiving service under this schedule have the option to procure the standby sales service offered by the Company under Schedule No. 459.

9. Rates contained in Schedule No. 440 will be used to determine balancing penalties and the standby sales service commodity price for customers procuring service under this schedule.

10. The Company shall give the customer as much notice of an impending curtailment as is reasonably possible under the circumstances at the time. The Company will not be liable for damages occasioned by interruption or discontinuance of service provided under this schedule.

11. In the event of capacity curtailment, customers under this schedule will be curtailed in accordance with Rule No. 14, Continuity Of Service. Interruptible customers are the first to be curtailed.

12. In the event of supply shortages, customers under this schedule shall receive their transport volumes except during an emergency requiring the use of the customer's gas to serve essential human needs. Appropriation of customer-owned gas during supply shortages is more fully described in Rule No. 21.

13. Insofar as operationally practicable, curtailment to each customer receiving service under this schedule shall be pro rata. Proration shall be based on equalization of the number of hours of curtailment for each customer in each heating season (July 1 through June 30).

14. In the event that it is necessary to discontinue service, the monthly minimum charge will be prorated on the basis of the ratio of the number of days on which service was available to the number of days in the billing period. For this purpose service will be considered available if curtailed by the Company less than eight hours in any particular day.

15. Service under this schedule is subject to the general rules and regulations contained in this tariff and to those prescribed by regulatory authorities.

(continued)

SCHEDULE 456 (continued)

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

16. Upon mutual agreement between Company and customer, a customer whose business is of a seasonal nature may limit transportation service to their seasonal operating period.

17. The Company is not obligated to maintain long-term gas supplies for transportation customers. Therefore, if a customer provided service under this schedule desires to change to a sales service schedule, the customer shall be liable for any additional charges associated with incremental gas supply costs, if they are higher than average supply costs.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-___

AVISTA CORP

BRIAN J. HIRSCHKORN
Exhibit No. 703

Rate Design & Rate Spread

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
12 Months Ended December 31, 2006
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Revenue Under Present Rates	Increase/ (Decrease)	Revenue Under Proposed Rates	Therms (000s)	Increase/ (Decrease) Per Therm	Revenue Percentage Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Residential	410	$76,444	$1,959	$78,403	49,375	3.97¢	**2.6%**
2	General Service	420	39,490	711	40,201	28,349	2.51¢	**1.8%**
3	Large General Service	424	4,933	71	5,004	3,710	1.91¢	**1.4%**
4	Interruptible Service	440	3,423	45	3,468	3,355	1.34¢	**1.3%**
5	Seasonal Service	444	244	-37	207	186	-19.89¢	**-15.1%**
6	Transportation Service	456	2,404	226	2,630	35,312	0.64¢	**9.4%**
7	Special Contract	447	476	0	476	5,673	0.00¢	**0.0%**
8	Total		$127,414	$2,975	$130,389	125,960	2.36¢	**2.3%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Rates	Change	Proposed Rates
Residential Service Schedule 410		
$5.00 Customer Charge	$0.50/month	$5.50 Customer Charge
All Therms - 144.931¢/Therm	2.979¢/therm	All Therms - 147.910¢/Therm
General Service Schedule 420		
$6.00 Customer Charge	$0.50/month	$6.50 Customer Charge
All Therms - 136.555¢/Therm	2.279¢/therm	All Therms - 138.834¢/Therm
Large General Service Schedule 424		
$65.00 Customer Charge	$0.00/month	$65.00 Customer Charge
All Therms - 130.913¢/Therm	1.913¢/therm	All Therms - 132.826¢/Therm
Interruptible Service Schedule 440		
All Therms - 102.031¢/Therm	1.313¢/therm	All Therms - 103.344¢/Therm
Seasonal Service Schedule 444		
All Therms - 130.887¢/Therm	-19.772¢/therm	All Therms - 111.115¢/Therm
Transportation Service Schedule 456		
$187.50 Customer Charge	$12.50/month	$200.00 Customer Charge
1st 10,000 Therms - 12.900¢/Therm	1.226¢/therm	1st 10,000 Therms - 14.126¢/Therm
Next 20,000 Therms - 7.757¢/Therm	0.737¢/therm	Next 20,000 Therms - 8.494¢/Therm
Next 20,000 Therms - 6.373¢/Therm	0.606¢/therm	Next 20,000 Therms - 6.979¢/Therm
Next 200,000 Therms - 4.984¢/Therm	0.474¢/therm	Next 200,000 Therms - 5.458¢/Therm
Over 250,000 Therms - 2.520¢/Therm	0.240¢/therm	Over 250,000 Therms - 2.760¢/Therm

Avista Utilities
Avg. Monthly Cost per Customer
for Meters, Services, Meter Reading, Billing & Customer Assistance
Oregon Gas - Schedules 410 & 420
12 Months Ended December 31, 2006

		Sch. 410			Sch. 420		
Line No.	(a)	2006 Annual Cost (b)	No. of Billings (c)	2006 Cost per Bill (d)	2006 Annual Cost (e)	No. of Billings (f)	2006 Cost per Bill (g)
1	Meter Reading	$ 164,837	977,086	$ 0.17	$ 21,880	129,693	$ 0.17
2	Billing & Bill Assistance	$ 1,686,271	977,086	$ 1.73	$ 223,826	129,693	$ 1.73
3	Meters (1)	$ 1,586,909	977,086	$ 1.62	$ 711,955	129,693	$ 5.49
4	Services (2)	$ 2,876,470	977,086	$ 2.94	$ 381,807	129,693	$ 2.94
5	Total	$ 6,314,487	977,086	**$ 6.46**	$ 1,339,468	129,693	**$ 10.33**

Line No.		Sch. 410	Sch. 420
	(1) Meters-Expense		
6	Depreciation Exp.	$ 452,529	$ 203,024
7	Return on Net Plant (3)	1,134,380	508,931
8	Total	$ 1,586,909	$ 711,955
	(2) Services-Expense		
9	Depreciation Exp.	$ 917,689	$ 121,809
10	Return on Net Plant (4)	1,958,781	259,998
11	Total	$ 2,876,470	$ 381,807
	(3) Meter-ROR		
12	Gross Plant	$ 16,723,665	$ 7,502,947
13	Less: Acc. Depr.	4,091,373	1,835,564
14	Net Plant	$ 12,632,292	$ 5,667,383
15	Times: Prop. ROR	0.0898	0.0898
16	Return Requirement	$ 1,134,380	$ 508,931
	(4) Services-ROR		
17	Gross Plant	$ 45,431,778	$ 6,030,363
18	Less: Acc. Depr.	23,619,075	3,135,066
19	Net Plant	$ 21,812,703	$ 2,895,297
20	Times: Prop. ROR	0.0898	0.0898
21	Return Requirement	$ 1,958,781	$ 259,998