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

AVISTA Corp.

August 14, 2013

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Dr, SE
Salem, OR 97302-1166

RE: Advice 13-03-G/UG- 246 – Avista Corporation's Request for General Rate Revision

In accordance with Oregon Administrative Rules, Avista Corp., dba Avista Utilities (Avista or Company), respectfully submits an original and 30 copies of the Company's trial brief, testimony and associated exhibits in support of its request for a general rate revision associated with the Company's Tariff P.U.C OR. No. 5. The Company is requesting the proposed revisions to the following enclosed tariff sheets:

Fourteenth Revision Sheet 410	Canceling	Thirteenth Revision Sheet 410
Thirteenth Revision Sheet 420	Canceling	Twelfth Revision Sheet 420
Thirteenth Revision Sheet 424	Canceling	Twelfth Revision Sheet 424
Thirteenth Revision Sheet 440	Canceling	Twelfth Revision Sheet 440
Fourteenth Revision Sheet 444	Canceling	Thirteenth Revision Sheet 444
Twelfth Revision Sheet 456	Canceling	Eleventh Revision Sheet 456
Second Revision Sheet 493	Canceling	First Revision Sheet 493

Please note that Exhibit 401 of Stephen Harper is being provided in electronic format only due to the voluminous nature of this file. Avista's CONFIDENTIAL Exhibit No.502 and associated Attachments 7, and 11 -18 are being provided under a sealed separate envelope, marked CONFIDENTIAL. Additionally, three (3) copies of supporting work papers have also been included with this filing. Mr. La Bolle's workpapers are CONFIDENTIAL and are being provided under a sealed separate envelope, marked CONFIDENTIAL.

Copies of the Company's responses to the Standard Data Requests are being provided under separate cover.

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

Sincerely,

David J. Meyer
Vice President and Chief Counsel for Regulatory and Governmental Affairs

Enclosure
cc: 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, (UG-246) upon the parties listed below by mailing a copy thereof, postage prepaid and/or by electronic mail.

Judy Johnson
Oregon Public Utility Commission
PO Box 1088
3930 Fairview Industrial Drive SE
Salem, OR 97302
Judy.johnson@state.or.us

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

Dated at Spokane, Washington this 14th day of August 2013.

Wendy Manskey

Wendy Manskey
Rates Coordinator

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG-246

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. This brief is submitted to meet the requirements of OAR 860-022-0019.

1.

Avista provides natural gas service in the State of Oregon and is a public utility subject to the Public Utility Commission of Oregon'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. As of December 31, 2012, Avista supplied retail electric service to 360,459 customers and retail natural gas service to 320,580 customers, including approximately 96,650 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.
Vice President and 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
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Kelly Norwood
Vice President, State and Federal Regulation
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E-mail: kelly.norwood@avistacorp.com

3.

The test period being used by the Company is the twelve months ended December 31, 2014, presented on a forecasted basis. 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 4.69 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 base rates (including natural gas costs) for Oregon retail customers of $9,481,000, or 9.5 percent, which would produce an overall rate of return of 7.83 percent and a return on equity of 10.1 percent. Pursuant to ORS 757.220, the revised schedules contain an effective date of September 16, 2013.

4.

The Company acquired its Oregon natural gas operations from CP National in 1991. In the past 23 years that Avista has operated these properties, Avista has filed only four general rate increase requests[1]. A combination of capital additions, declining margins and increases in general business expense now require the Company to request an increase in overall base retail rates of $9,481,000.

The Company used the cost of service results prepared by Company witness Miller as a guide in the proposed spread of the requested increase to the various service schedules. As described in Company witness Ehrbar's testimony, the spread of the proposed increase generally results in the margin-to-cost ratios for the various service schedules moving approximately 50% closer to 1.00 (unity) for Schedules 420, 424, 444 and 456, and to unity for Schedules 410 and 440. As a result, the proposed rate spread would result in an increase of 10.4% to residential customers, and increases ranging between 1.0% and 9.6% to other rate schedules.

5.

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

(a) Policy and Operations – Exhibit 100. **Scott L. Morris**, Chairman of the Board, President and Chief Executive Officer of Avista Corporation, presents an overview of the filing and identifies the cost increases that make this filing necessary. Mr. Morris describes efforts to reduce operating costs and explains the Company's customer support programs that are in place to assist customers.

(b) Financial Overview, Capital Structure, and Overall Rate of Return – Exhibit 200. **Mark T. Thies**, Senior Vice President and Chief Financial Officer, will address the Company's capital structure, the proposed cost of embedded debt and the overall rate of return. He will

[1] Dockets UG-153, UG-181, UG-186 and UG-201.

explain the actions the Company has taken to acquire needed capital and improve Avista's financial condition in recent years.

(c) Return on Equity – Exhibit 300. **William E. Avera**, as President of Financial Concepts and Applications (FINCAP), Inc., has been retained to present testimony with respect to the reasonableness of the Company's proposed overall capital structure and will testify in support of the proposed 10.1% return on equity.

(d) Gas Supply and Storage - Exhibit 400. **Stephen Harper**, Director, Gas Supply, will describe Avista's natural gas resource planning process, discuss the Company's purchase of the Klamath Falls Lateral in 2013, and provide an update on the Company's 2012 Natural Gas Integrated Resource Plan.

(e) Major Capital Investment Projects – Exhibit 500. **Larry La Bolle**, Director, Federal and Regional Affairs, will describe the replacement of the Company's Customer Information System (CIS), and Avista's Aldyl A pipe replacement program.

(f) Revenue Requirement and Allocations - Exhibit 600. **Elizabeth M. Andrews,** Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposal. 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 the allocation methodologies. She will also explain forecasted operating results, including expense and rate base adjustments made to actual operating results and rate base.

(g) Capital Projects – Exhibit 700. **Dave B. DeFelice**, Senior Business Analyst, will describe the Company's proposed regulatory treatment of capital investments in utility plant through June 30, 2014.

(h) Long-Run Incremental Cost of Service – Exhibit 800. **Joseph D. Miller**, Senior Regulatory Analyst, sponsors the long-run incremental cost study for Oregon natural gas service. Mr. Miller discusses his study results and how each schedule's present and proposed rates compare to the indicated cost.

(i) Rate Design and Rate Spread – Exhibit 900. **Patrick D. Ehrbar**, Manager, Rates and Tariffs, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. Mr. Ehrbar also discusses the Forecasted Revenue Load Adjustment.

6.

The following exhibits are attached pursuant to OAR 860-022-0019:

(a) Exhibit A. The information required by OAR 860-022-0019(1)(a)-(f).

(b) Exhibit B. From Ms. Andrew's Exhibit 601, page 1, which shows the results of operations for Avista's Oregon jurisdiction before and after the proposed rate change, as required by OAR 860-022-0019(1)(g).

(c) Exhibit C. This exhibit shows the effect of the proposed rate change on each class of customers as required by OAR 860-022-0019(1)(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: August 14, 2013.

David J. Meyer
Vice President and 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 base revenues, including natural gas costs, that would be collected under the proposed rates is $108,839,000.

B. The dollar amount of revenue change requested is $9,481,000.

C. The percentage change in base revenues requested is 9.5 percent.

D. The forecasted test period proposed is January 1, 2014 to December 31, 2014.

E. The requested overall rate of return is 7.83 percent and the requested return on equity is 10.1 percent.

F. The rate base proposed in this filing is $176,201,000.

Exhibit B

AVISTA UTILITIES
OREGON NATURAL GAS
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description	PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2014 AMA Forecasted Test Period	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Forecasted Proposed Total (AMA)
		a	*b*	*c*	*d*	*e*
1	OPERATING REVENUES					
2	Total General Business	$95,274	1,161	96,435	9,481	105,916
3	Total Transportation	2,888	35	2,923	0	2,923
4	Other Revenues	67,391	(67,247)	144	0	144
5	Total Operating Revenues	165,553	(66,051)	99,502	9,481	108,983
6						
7	OPERATING EXPENSES					
8	Gas Purchased	119,814	(64,355)	55,459	0	55,459
9	Operation and Maintenance	12,734	(907)	11,827	51	11,878
10	Administration & General	7,675	128	7,803	229	8,032
11	Total Operation & Maintenance	140,223	(65,134)	75,089	280	75,369
12						
13	DEPRECIATION, AMORTIZATION, TAXES					
14	Taxes Other than Income	5,654	(751)	4,903	699	5,602
15	Depreciation & Amortization	5,022	4,027	9,049	0	9,049
16	Total Operating Expenses	150,899	(61,858)	89,041	979	90,020
17						
18	OPERATING INCOME BEFORE FIT	14,654	(4,193)	10,461	8,502	18,963
19						
20	INCOME TAXES					
21	Current Federal Income Taxes	72	(1,355)	(1,283)	2,976	1,693
22	Debt Interest	0	(288)	(288)	0	(288)
23	Deferred Federal Income Taxes	3,817	0	3,817	0	3,817
24	State Income Taxes	268	(323)	(55)	0	(55)
25	Total Income Taxes	4,157	(1,966)	2,191	2,976	5,167
26						
27	NET OPERATING INCOME	$10,497	($2,227)	$8,270	$5,526	$13,796
28						
29						
30	RATE BASE					
31	Utility Plant in Service	269,913	42,241	312,154	0	312,154
32	Less: Accum Depr and Amort	(94,566)	(11,976)	(106,542)	0	(106,542)
33	Net Utility Plant	175,347	30,265	205,612	0	205,612
34						
35	Accumulated Deferred FIT	(36,866)	(7,694)	(44,560)	0	(44,560)
36	Inventory	3,084	0	3,084	0	3,084
37	Prepaid Pension (1)	0	5,710	5,710	0	5,710
38	Working Capital	0	6,355	6,355	0	6,355
39						
40	TOTAL RATE BASE	$141,565	$34,636	$176,201	$0	$176,201
41						
42	RATE OF RETURN	7.41%		4.69%		7.83%

(1) Prepaid Pension Asset of $5.71 million is offset by $2.0 million Accumulated Deferred Federal Income Tax (ADFIT), resulting in a net Prepaid Pension rate base amount of $3.71 million. See detail information at Andrews Exhibit No. 602, page 5.

Avista Utilities
Docket No. UG-246
Rate Spread Summary
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2014

	Type of Service	Schedule Number	Avg. No. of Customers	Annual Therms	Avg. Use per Customer per Month	Revenue at Pres. Rates ($000's)	Avg. Bill Under Pres. Rates	Revenue Percentage Increase	Revenue Increase ($000's)	Avg. Increase per Customer per Month	Revenue at Prop. Rates ($000's)	Avg. Bill Under Prop. Rates
1	Residential	410	85,557	48,912,477	48	$62,855	$61.63	10.4%	$6,548	$6.41	$69,403	$68.04
2	General Service	420	11,231	26,046,807	193	28,616	$212.05	9.6%	2,738	$20.29	31,354	$232.34
3	Large General Service	424	80	4,098,586	4,274	3,535	$3,687	1.0%	36	$37	3,570	$3,723
4	Interruptible Service	440	35	2,536,455	6,039	1,221	$2,908	4.6%	56	$133	1,277	$3,041
5	Seasonal Service	444	3	238,479	5,817	207	$5,044	3.0%	6	$151	213	$5,195
6	Transportation Service	456	37	30,374,148	68,257	2,645	$5,943	3.7%	97	$219	2,742	$6,162
7	Special Contract	447	3	7,350,651	204,185	279	$7,740	0.0%	0	$0	279	$7,740
8	Total		96,947	119,557,603		$99,358		9.5%	$9,481		$108,839	

EXHIBIT C

Exhibit B

AVISTA UTILITIES
OREGON NATURAL GAS
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2014

		PRESENT RATES			WITH PROPOSED RATES	
Line No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2014 AMA Forecasted Test Period	Proposed Revenues & Related Exp	Forecasted Proposed Total (AMA)
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36	Inventory	3,084	0	3,084	0	3,084
37	Prepaid Pension (1)	0	5,710	5,710	0	5,710
38	Working Capital	0	6,355	6,355	0	6,355
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40	TOTAL RATE BASE	$141,565	$34,636	$176,201	$0	$176,201
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42	RATE OF RETURN	7.41%		4.69%		7.83%

(1) Prepaid Pension Asset of $5.71 million is offset by $2.0 million Accumulated Deferred Federal Income Tax (ADFIT), resulting in a net Prepaid Pension rate base amount of $3.71 million. See detail information at Andrews Exhibit No. 602, page 5.

Avista Utilities
Docket No. UG-246
Rate Spread Summary
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2014

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3	Large General Service	424	80	4,098,586	4,274	3,535	$3,687	1.0%	36	$37	3,570	$3,723
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7	Special Contract	447	3	7,350,651	204,185	279	$7,740	0.0%	0	$0	279	$7,740
8	Total		96,947	119,557,603		$99,358		9.5%	$9,481		$108,839	

EXHIBIT C

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF SCOTT L. MORRIS
REPRESENTING AVISTA CORPORATION

Policy and Operations

I. INTRODUCTION

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

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

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

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

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

I am a member of the Western Energy Institute board of directors, a member of the Gonzaga University board of trustees, a member of Edison Electric Institute board of directors, a member of the American Gas Association, a member of ReliOn board of directors, and board director of the Washington Roundtable. On January 1, 2011, I was appointed to the Federal Reserve Bank of San Francisco, Seattle Branch board of directors and in January 2012 I was appointed as Chairman of the Board to Innovate Washington by Governor

Christine Gregoire. I also serve on the board of trustees of Greater Spokane Incorporated.

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

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

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

Q. Are you sponsoring exhibits in this proceeding?

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

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

A. Yes. A combination of increasing rate base and increases in general business expenses requires the Company to request an overall increase in billing rates of $9.481 million or 9.8%. This request is based on a proposed rate of return of 7.83%, with a capital structure common equity component of 50%, and a 10.1% return on equity. The Company is utilizing a forecasted test period for the calendar year 2014. The forecasted test period was selected to best reflect the conditions during the time new rates would be in effect, as discussed further by Company witness Ms. Andrews. The Company used the results of a long-run incremental cost study as a starting point in the proposed spread of the requested increase to the various customer rate schedules. Company witnesses Mr. Miller and Mr. Ehrbar testify to these rate spread issues.

Based on an average usage level of 48 therms per month, the average residential bill would increase $6.17 per month, or 10.6%, from $58.00 to $64.17.

II. OVERVIEW OF AVISTA

Q. Please briefly describe Avista Utilities.

A. Avista Utilities provides natural gas distribution service in southwestern and northeastern Oregon. The Company, headquartered in Spokane, Washington, also provides electric and natural gas service within a 26,000 square mile area of eastern Washington and northern Idaho.[1] Of the Company's 360,459 electric and 320,580 natural gas customers (as of December 31, 2012), approximately 96,650 were Oregon customers. A map showing Avista's electric and natural gas service areas is provided in Exhibit No. 101.

As of December 31, 2012, Avista Utilities had total assets (electric and natural gas) of approximately $3.9 billion (on a system basis), with electric retail revenues of $730 million (system) and natural gas retail revenues of $302 million (system). As of December 2012, the Utility had 1,518 full-time employees.[2]

The Company acquired its Oregon natural gas operations from CP National in 1991. Avista serves four counties in southwest Oregon and one county in northeast Oregon, which include Medford, Klamath Falls, Roseburg, Ashland, Grants Pass and LaGrande as shown on page 1 of Exhibit No. 101.

The Company's Oregon service area includes approximately 82 miles of natural gas distribution mains and 2,000 miles of distribution lines. Natural gas is received at more than 20 points along interstate pipelines and distributed to almost 97,000 residential, commercial and industrial customers.

Avista purchases natural gas for its distribution customers in wholesale markets at

[1] Avista also serves approximately 25 retail electric customers in western Montana.
[2] The number of full time employees was decreased by 55 in 2013, as part of the Voluntary Severance Incentive Plan, as explained later in my testimony.

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

Avista has a long history of innovation and environmental stewardship. At the turn of the 19th century, the Company built its first renewable hydro generation plant on the banks of the Spokane River. In the 1980's, Avista developed an award-winning biomass plant (Kettle Falls) that generates energy from wood-waste.

Avista was one of the three original developers of the natural gas 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 one-third share of this underground gas storage facility. Development began in the 1960's and the project first went into service in 1972.

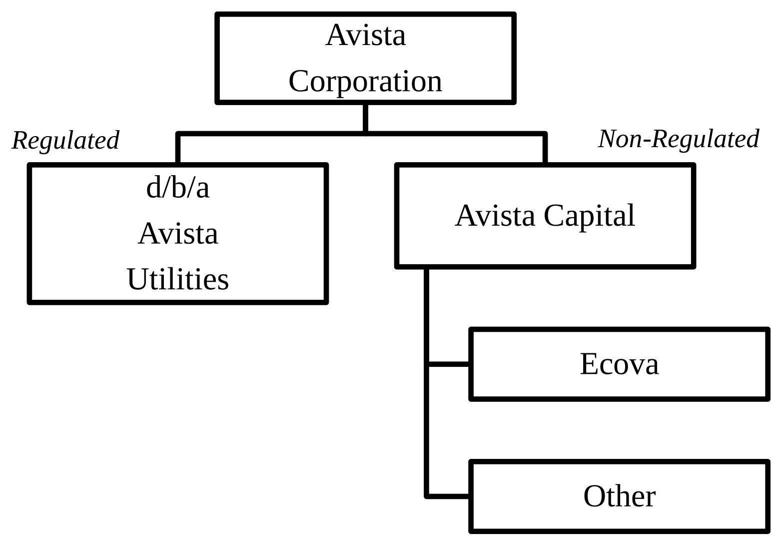
Q. Please describe Avista's current business focus for its utility operations.

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

Q. Please briefly describe Avista's subsidiary businesses.

A. Avista Corp.'s primary subsidiary is the information and technology business, Ecova, described below, which is headquartered in Spokane, Washington.

The following is a diagram of Avista's corporate structure:



Advantage IQ, and Ecos, an Advantage IQ subsidiary delivering electric and natural gas utility demand-side management services, joined forces to become Ecova in October 2011. Ecova provides utility expense management and energy management solutions to multi-site companies across North America. This includes more than 450,000 business sites. Ecova clients include Fortune 1000 companies such as GameStop, Panda Restaurant Group, Petco, Shell, Staples, and many North American electric and natural gas utilities. Avista currently holds a 79.2% share in Ecova, which is held under Avista Capital.

III. REASONS FOR AVISTA'S RATE INCREASE REQUEST

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

A. Before I provide additional details related to our rate request, I would like to specifically address the issue of the economy. The people of the State of Oregon and our Country continue to face the challenges of a recovering economy. I can assure you that the decisions we make at Avista are not made without taking into consideration the current state of the economy, as well as other issues raised by our customers.

With regard to cost-control, we contracted with a consultant in 2010 to take an independent, objective look at opportunities to do our work more efficiently and more cost-effectively. In the past several years we have also managed our capital budget in order to mitigate rate impacts to customers. There are limitations however, on how far we, as a utility, can go with cost-cutting before we begin to jeopardize reliability of service and customer satisfaction.

At the same time, while we continue to maintain tight controls on capital and O&M budgets, our customer service surveys indicate that customer satisfaction remains high. Our overall customer satisfaction from our voice-of-the-customer surveys in the second quarter of 2013 was 94% in our Oregon, Idaho, and Washington operating divisions.[3] This rating reflects a positive experience for customers who have contacted Avista related to the customer or field service they received.

[3] The purpose of the VOC Survey is to measure and track customer satisfaction for Avista Utilities' customer contacts – customers who have contact with Avista through the Call Center and/or work performed through an Avista construction office.

With regard to low income customers and seniors, we understand that when energy costs go up, especially in times like these, it affects everyone. But we make it a priority to do the best we can to assist customers who need more help. I will describe in more detail the Company's support programs later in my testimony.

Our last general rate case, which was filed in 2010, resulted in a rate increase in three increments (March 2011, June 2011 and June 2012) totaling approximately 3.5%. Therefore, it has been three years since Avista has filed a General Rate Case in Oregon.

With regard to the increased costs driving our rate increase request, over 92% (or approximately $8.75 million) of the Company's need for additional rate relief is related to increases in total rate base, including changes in net plant investment (including return on investment, depreciation and taxes, offset by the tax benefit of interest), resulting in an increase of approximately $36.9 million in net rate base for the Oregon jurisdiction. The remaining 8% (or approximately $730,000) of the Company's requested revenue requirement is related to a three-year net increase in Operating and Maintenance (O&M) and Administrative and General (A&G) expenditures since the Company's last filed rate case. Major capital investment projects included in this rate request include the Company's Customer Information System (CIS) and Aldyl A pipe replacement projects, as more fully described by Company witness Mr. La Bolle.

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

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

IV. COST MANAGEMENT AND EFFICIENCIES

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

A. In the last couple of years we have renewed our efforts to control our costs and improve efficiency. We are focused on long-term sustainable savings to continuously improve our service to customers and manage costs into the future.

As an example, in October 2012, the Company's Board of Directors approved a Voluntary Severance Incentive Plan (VSIP) that proposed to reduce the total utility workforce in order to achieve necessary long-term, sustainable, Company-wide savings. The VSIP was designed as a "Double Yes" program. Eligible employees (regular full and part-time employees of Avista Utilities who were not covered by a collective bargaining agreement) had an opportunity to voluntarily leave the Company, (which constituted the 1st Yes). Employees who elected to participate in the program (total of 110), however, would still require approval by the Company's management. After weighing short and long term business needs, critical skill sets, and the ability to accommodate departure requests, the Company determined that 55 of the employee requests would be approved (constituting the 2nd Yes of the "Double Yes" approach).

Each participant in the program were entitled to receive severance pay based on the participant's years of service and base pay as of December 31, 2012, not to exceed 78 weeks of a participant's base pay. Severance pay was distributed in a single lump sum cash payment to each participant in January 2013.

Through this program, effective January 1, 2013, Avista reduced its number of employees by 55, or approximately 6 percent, of the eligible 919 non-union employees. The cost of the program of $7.3 million was expensed in December 2012, and the annual benefits on a going-forward basis are approximately $5 million per year. Avista has a process in place to regularly review the total number of employees in order to carefully manage the growth in the number of employees over time.

Some of the other measures that we are continuing are briefly explained below.

Hiring Restriction

The Company continues to operate under a hiring restriction which requires approval by the Chairman/President/CEO, President of the Utility, the CFO, and the Sr. VP for Human Resources for all replacement or new hire positions.

Reduced Pension Benefit for New Hires

As part of the new contract negotiated with Avista's bargaining unit employees, the Defined Benefit Pension Plan's benefit formula was reduced by approximately 28% for all bargaining unit new hires, effective January 1, 2011. This change was earlier made for non-bargaining unit employees effective January 1, 2006.

Performance Excellence Initiative

In May 2010, the Company enlisted the help of Booz & Company to work with us on what we have referred to as Performance Excellence. They brought with them industry knowledge, expertise and a phased-approach. Phase 1 involved assessing and identifying Avista's top opportunities to better align our resources so we can run our business more efficiently, and be better prepared to meet customers' future needs for energy and energy information. In Phase 2 we designed changes to our processes to capture these opportunities. These changes encompassed six areas: T&D Work Estimating/Scheduling, Supply Chain Sourcing, Integrated Planning (Capital & O&M), Asset Management, Enterprise Technology, and Integrated Measurement (Metrics). In Phase 3, teams completed work plans to implement the new designs. The changes have resulted in either improved efficiency, avoided costs, and/or enhanced customer service.

Customer Touch Point Teams

As part of a Business Process Improvement (BPI) initiative, in the fall of 2011 a team from across the Company identified every contact point or touch point a customer has with Avista. The objective of the initiative was to improve our customers' overall experience when doing business with us, as well as improve responsiveness in a respectful and least cost manner. This team identified a "map" of 168 different customer interactions or touch points. Designing improvements to these touch points required that we take an outside-in view of the customer interaction. The Company used the BPI methodology (plan, analyze, design, implement and sustain) and each team spends approximately four weeks on their specific touch point. To date, we have had 26 teams and they have completed over 55 distinct touch points. For example, two recent teams redesigned the way we welcome new customers to Avista, and the way we notify customers when we're planning work near their home or business.

V. COMMUNICATIONS WITH CUSTOMERS

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

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

We have listened to our customers and learned that they want information and conversations with Avista employees to better understand the choices they have to manage how they use energy and the forces that are impacting their energy prices.

That's why we are continuing to build on our communications, so that customers receive information directly from us on issues important to them. We are also continuing to engage employees in the Company in our efforts to more directly communicate with customers.

Q. How has the Company stepped-up communications with its customers?

A. One of the important principles in our intensified outreach is to meet customers where they gather. Our customer conversation uses traditional and non-traditional communication channels, including one-on-one and group presentations, print, radio, website, newsletters, videos, social media and direct emails.

Another important customer segment that we seek to reach are those customers who gather online. We are continuing to focus on our social media program with the Avista blog as our foundation. We also communicate on Twitter©, in online discussion forums when appropriate, and this year have added the Avista Utilities Facebook© page. For customers who want a more private online conversation, we offer customers a conversation email account to make sure they're comfortable communicating with us.

One important customer communication channel is our website at www.avistautilities.com. A section focusing on rates provides customers a video on how rates are set, including the regulatory process; other videos focus on the components of general rate requests, and provide additional information on general rate requests.

Our employees provide excellent customer service, and this focus on communicating with our customers includes providing employees messaging and new tools and training to make it easier to have conversations about Avista with friends, family and customers. We are finding that once a customer talks with one of our employees and has the opportunity to voice their concerns and receive answers to their questions, their satisfaction level increases. We're listening to our customers' point-of-view and sharing ours about energy issues that directly affect us all.

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

VI. CUSTOMER SUPPORT PROGRAMS

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

A. Avista Utilities offers a number of programs for its Oregon customers, such as energy efficiency programs, the Low Income Rate Assistance Program (LIRAP), Project Share for emergency assistance to customers, the 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.

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

A. Avista Utilities' Low-Income Rate Assistance Program (LIRAP) approved by the Commission in 2002 collects revenue under Schedule 410, "General Residential Natural Gas Service–Oregon." The current rate for LIRAP is approximately 0.4% of the current volumetric billing rate. The purpose of LIRAP is to reduce the energy cost burden among those customers least able to pay energy bills. These funds are distributed by community action agencies in a manner similar to the Federal and State-sponsored Low Income Home Energy Assistance Program (LIHEAP). Avista Utilities' LIRAP program supplements the reach of available LIHEAP funds. LIRAP provided 680 grants and distributed a total of $200,011 during the 2012/2013 heating season in its Oregon service territory.

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

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

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

A. Yes. Comfort Level Billing helps smooth out the seasonal highs and lows of customers' energy usage and provides the customer with the option to pay the same bill amount each month of the year. This allows customers to more easily budget for energy bills and it also avoids higher winter bills. This program has been well-received by participating customers. A total of 8,920 (or 9%) 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 2012, 13,951 Oregon customers were provided with over 27,600 such payment arrangements.

Q. Please summarize Avista's CARES program.

A. In Oregon, Avista is currently working with over 247 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 2012 heating season, 5,256 Oregon customers received $1,056,034 in various forms of energy assistance (Avista LIRAP, Federal LIHEAP program, Project Share, and local community funds). This program and the partnerships we have formed have been invaluable to customers who often have nowhere else to go for help.

VII. OTHER COMPANY WITNESSES

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

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

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

Mr. William E. Avera, as President of Financial Concepts and Applications (FINCAP), Inc., has been retained to present testimony with respect to the reasonableness of the Company's proposed overall capital structure and will testify in support of the proposed 10.1% return on equity.

Mr. Stephen Harper, Director, Gas Supply, will describe Avista's natural gas resource planning process, discuss the Company's purchase of the Klamath Falls Lateral effective January, 1 2013, and provide an update on the Company's 2012 Natural Gas Integrated Resource Plan.

Mr. Larry La Bolle, Director, Federal and Regional Affairs, will describe the replacement of the Company's Customer Information System (CIS), and Avista's Aldyl A pipe replacement program.

Ms. Elizabeth Andrews, Manager, Revenue Requirements, will discuss the Company's overall revenue requirement proposal. 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 the allocation methodologies. She will also explain forecasted operating results, including expense and rate base adjustments made to actual operating results and rate base.

Mr. Dave DeFelice, Senior Business Analyst, will describe the Company's proposed regulatory treatment of capital investments in utility plant through June 30, 2014.

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

Mr. Patrick Ehrbar, Manager, Rates and Tariffs, discusses the spread of the annual revenue changes among the Company's general service schedules and related rate design. Mr. Ehrbar also discusses the Forecast Revenue Load Adjustment.

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

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF MARK T. THIES
REPRESENTING AVISTA CORPORATION

Financial Overview, Capital Structure and Overall Rate of Return

Table of contents for the testimony of Mark T. Thies:

I. INTRODUCTION

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

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

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

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

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

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

A. I will provide a financial overview of the Company and will explain the overall rate of return proposed by the Company in this filing for its natural gas operations. The proposed rate of return is derived from Avista's long-term cost of debt, and common equity, weighted in proportion to the proposed capital structure.

I will address the proposed capital structure, as well as the proposed cost of debt and equity in this filing. Dr. Avera, on behalf of the Company, will provide additional testimony related to the appropriate return on equity for Avista, based on the specific circumstances of the Company, together with the current state of the financial markets.

In brief, I will provide information that shows:

- Avista's plans call for significant capital expenditure requirements for the utility over the next two years to assure reliability in serving our customers and meeting customer growth. Capital expenditures of approximately $526 million are planned for 2013-2014 for customer growth, necessary maintenance and replacements of our natural gas utility systems, and investment in generation, transmission and distribution facilities for the electric utility business. Capital expenditures of approximately $1.3 billion are planned for the five year period ending December 31, 2017. Avista needs adequate cash flow from operations to fund these requirements, together with access to capital from external sources under reasonable terms.

- Avista's corporate credit rating from Standard & Poor's (S&P) is currently BBB and from Moody's Investors Service (Moody's) it is Baa2. Avista must operate at a level that will support a solid investment grade corporate credit rating in order to access capital markets at reasonable rates, which will result in lower long-term borrowing costs to customers. A supportive regulatory environment is an important consideration by the rating agencies when reviewing Avista. Maintaining solid credit metrics and credit ratings will also help support a stock price necessary to issue equity under reasonable terms to fund capital requirements.

- The Company has proposed an overall rate of return of 7.83%, including a 50% equity ratio and a 10.1% return on equity. Our cost of debt is 5.55%. We believe the overall rate of return of 7.83% provides a reasonable balance of the competing objectives of financial health for the utility, and the impacts that increased rates have on our customers.

The Company's ongoing efforts to carefully manage its operating costs and capital expenditures are an important part of our performance, but are not sufficient without revenues from the general rate request for our natural gas business in this case. Sufficient cash flows from operations can only be achieved with the support of regulators in allowing the timely recovery of costs and the ability to earn a reasonable 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 two principal rating agencies are summarized on page 1. Page 2 includes Avista's actual capital structure at December 31, 2012 and the forecasted capital structure at December 31, 2014 utilized for this case. Pages 3 through 4 are supporting documentation for page 2.

II. FINANCIAL OVERVIEW

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

A. We are operating the business efficiently to keep costs as low as practicable for our customers, while at the same time ensuring that our energy service is reliable, and customers are satisfied. An efficient, well-run business is not only important to our customers, but also to investors. Additionally, 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 ratings.

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

A. We are working to assure there are adequate funds for operations, capital expenditures and debt maturities. We obtain a portion of these funds through the issuance of long-term debt and common equity. During 2011 and 2012 the Company priced and issued $165 million of long-term debt at historically low rates and issued $55.6 million of common equity. We are planning to issue up to $50 million of common stock in 2013, in order to maintain our capital structure at an appropriate level for our business.

We are anticipating the cost of debt to decrease to 5.55% by December 31, 2014, from 5.90% as of December 31, 2012. This decrease is primarily due to the 2013 issuance of $90 million three year loan agreement, at a fixed rate of 0.84 percent, which is being issued, in part, to refinance the Company’s $50.0 million of 1.68 percent First Mortgage Bonds that mature in December 2013.

The Company entered into forward-starting interest rate swaps for a total of $115 million as a hedge on a portion of the interest payments on forecasted issuances of long-term debt in 2014, 2015 and 2016. The Company continues to analyze the possibility of entering into additional transactions in order to reduce cash flow volatility and the associated retail rate impacts related to future interest rate variability.

Q. In addition to having credit ratings that will allow Avista to attract debt capital under reasonable terms, is it also necessary to attract capital from equity investors?

A. It is absolutely essential. Avista has two primary sources of external capital: debt and equity investors. As of June 30, 2013, Avista had approximately $2.8 billion of debt and equity. Approximately half of Avista’s outstanding debt and equity is funded by debt holders, and the other half is funded by equity investors and retained earnings. There tends to be significant emphasis on maintaining credit metrics and credit ratings that will provide access to debt capital markets under reasonable terms, however, access to equity capital markets are equally important. In fact, equity investors also focus on cash flows, capital structure and liquidity, much like debt investors. The level of common equity in the Company's capital structure can have a direct impact on its credit rating.

Equity capital growth generally comes in two forms: retained earnings and new stock issuances. Retained earnings represent the annual earnings of the Company that is not paid out to investors in dividends. The retained earnings are reinvested by the Company in utility capital expenditures to serve customers and other capital/investments, which avoids the need to issue new debt or new stock. Occasionally, it's necessary to issue common equity in order to maintain a balanced debt and equity capital structure. A balanced capital structure allows Avista access to both debt and equity markets under reasonable terms, on a sustainable basis. As previously noted, our capital requirements for the next five years are sizable at approximately $1.3 billion, which will need to be funded with both debt and equity.

Q. Are the debt and equity capital markets a competitive market?

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

Q. What is Avista doing to attract equity investment?

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

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

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

Dr. Avera provides additional testimony related to the appropriate return on equity for Avista that would allow the Company access to equity capital under reasonable terms, and on a sustainable basis.

III. CREDIT RATINGS

Q. How important are credit ratings for Avista?

A. Utilities require ready access to capital markets in all types of economic environments. The nature of our business with long-term capital projects, our obligation to serve, and the potential for significant volatility in commodity costs, necessitates the need to have the ability to go to the financial markets under reasonable terms on a regular basis. In order to have this ability, investors need to understand the risks related to any of their investments. To help investors assess the creditworthiness of a company, Nationally Recognized Statistical Rating Organizations (rating agencies) developed their own standardized ratings scale, otherwise known as credit ratings. These credit ratings indicate the creditworthiness of a company and assist investors in determining if they want to invest in a Company.

Q. Please summarize the credit ratings for Avista's debt securities.

A. Avista has credit ratings assigned by S&P and Moody's, two of the most widely recognized rating agencies. These credit ratings are summarized on page 1 of Exhibit No. 201.

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

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

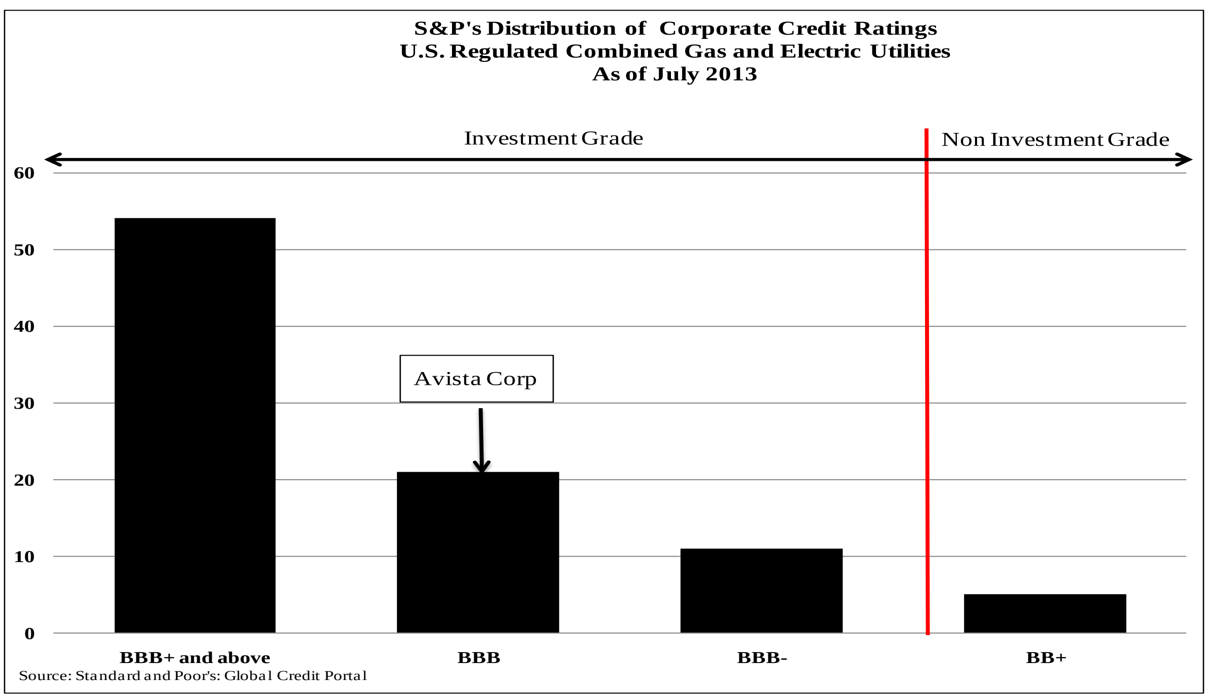
In challenging credit markets, where investors are less likely to buy corporate bonds (as opposed to U.S. Government bonds), a higher credit rating will attract more investors, and a lower credit rating could reduce or eliminate the number of potential investors. Thus, lower credit ratings may result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

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

A. Avista believes operating at a corporate credit rating level that is comparable with other US utilities providing both electricity and natural gas, is appropriate. Avista is currently able to support a corporate credit rating BBB, and has a long-term goal of operating at a Corporate Credit rating of BBB+. Operating at a BBB+ rating level will result in lower long-term borrowing costs to customers and provide additional security to the Company's stakeholders. We expect that a continued focus on the regulated utility, conservative financing strategies and a supportive regulatory environment will contribute toward an upgrade to a BBB+ credit rating.

As shown in Illustration No. 1, Avista's current S&P corporate credit rating of BBB, is below the average credit rating for U.S. Regulated Combined Gas and Electric Utilities. The Company's long-term goal is to operate at a credit rating of at least the utility average (BBB+). Operating at a BBB+ would likely attract additional investors, lower the Company's debt pricing, and makes us more competitive with other utilities.

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



Financially healthy utilities have lower financing costs which, in turn, benefit customers. In addition, financially healthy utilities are better able to invest in the required infrastructure over time to serve their customers, and to withstand the challenges facing the industry.

Q. What are the key credit factors S&P uses to establish credit ratings?

A. Credit factors utilized by S&P to establish credit ratings typically include an assessment of a company's Business Risk and Financial Risk. The Business Risk includes such items as country risk, industry risk, competitive position, and profitability. The Business Risk analysis is supported by statistics; however, it also involves subjective judgment. S&P assigns a Business Risk profile to each company that may range from the lowest of "Vulnerable" to the highest of "Excellent". Avista's Business risk profile is currently Excellent.

Financial risk is assessed primarily through quantitative means, particularly by using financial ratios. S&P's financial ratios are used to assist them in rating companies such as Avista. A few of these ratios that are commonly referred to in S&P's credit analysis are summarized in Illustration No. 2 below.

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

Standard & Poor's Financial Risk Indicative Ratios
(Corporate)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	**Greater than 60**	**less than 1.5**	**Less than 25**
Modest	**45 - 60**	**1.5-2**	**25 - 35**
Intermediate	**30 - 45**	**2-3**	**35 - 45**
Significant	**20 - 30**	**3-4**	**45 - 50**
Aggressive	**12 - 20**	**4-5**	**50 - 60**
Highly leveraged	**Less than 12**	**greater than 5**	**Greater than 60**
12 Months Ended 12/31/12 Ratios:			
Avista Adjusted (a)	16.63%	4.75%	55.12%

(a) Calculated as of 12/31/12 based on last known S&P methodology

The ratios above are utilized to determine the financial risk profile. Currently, Avista is in the Aggressive category. The financial risk category along with the business risk profile is then utilized in Illustration No. 3 below to determine a company's rating. S&P currently has Avista's corporate credit rating as BBB, based upon an Aggressive financial risk profile and Excellent business risk profile.

Illustration No. 3:

Standard & Poor's Business and Financial Risk Profile Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	$\boxed{\text{BBB}}$	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

S&P recently stated, "We could raise the [corporate credit] rating with significant financial improvement, including adjusted FFO to debt of 20% or more and adjusted debt to capital of 50% or less without any weakening of the business profile, but this is unlikely in the near term."[1]

Q. Please describe how S&P's Financial Risk ratios are calculated and what they mean?

A. The first ratio, Funds From Operations ("FFO")/total debt (%), calculates the amount of cash flow from operations as a percent of total debt. The ratio indicates the Company's ability to fund debt obligations. The second ratio, Debt/Earnings before interest, taxes, depreciation and amortization ("EBITDA"), is used as a proxy of debt repayment

[1] Standard and Poor's, Summary Avista Corp., June 27, 2013.

capacity for the Company. The ratio indicates the Company's ability to pay back debt obligations. The third ratio, total debt/total capital (%), is the amount of debt in our total capital structure. The ratio is an indication of the extent to which the Company is leveraged. The higher this ratio is the more risk the rating agencies recognize in their ratings and outlooks. S&P looks at many other financial ratios; however, these are the three commonly referenced when analyzing the Company's 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 (e.g., purchased power agreements and the unfunded status of pension and other post-retirement benefits) that negatively impact the ratios. For example, in 2012 S&P made adjustments to Avista's debt totaling approximately $187.3 million primarily related to post-retirement benefits, purchased power contracts, and non-recourse debt. The adjusted financial ratios for Avista are included in Illustration No. 2 above.

Q. What other risks are Avista and the utility sector facing that may impact credit ratings?

A. Avista's credit ratings are impacted by risks that could negatively affect the Company's cash flows. These risks include, but are not limited to, weather conditions, the effect of state and federal regulatory decisions on the ability to recover costs and earn a reasonable return, changes in wholesale energy prices, local and global economic conditions, access to capital markets at a reasonable cost, potential effects of legislation or administrative rulemaking, volatility and illiquidity in the wholesale energy market, and delays or changes in construction costs.

Credit ratings for the utility sector are also adversely impacted by large capital expenditures for new generation, transmission and distribution facilities, and environmental compliance. The utility sector is in a cycle of significant capital spending, which will likely be funded by significant issuances of debt and equity. This will likely affect the competition for financial capital.

The increased capital spending needs and resulting increased debt and equity issuances make regulatory support for full and timely recovery of prudently incurred costs critical to the utility sector.

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

A. The regulatory environment in which a company operates is a major qualitative factor in determining a company's creditworthiness.

S&P stated the following:

> Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program[2].

Due to the major capital expenditures planned by Avista, a supportive regulatory environment is essential.

[2] Standard and Poor's, Key Credit Factors: Business and Financial Risks in the Investor-owned Utility Industry, March 2010.

IV. CASH FLOW

Q. What are the Company's sources to fund capital requirements?

A. The Company utilizes cash flow from operations, long-term debt and common stock issuances to fund its capital expenditures. Additionally, on an interim basis, the Company utilizes its credit facilities to fund short-term cash requirement needs and capital expenditures until longer-term financing can be obtained.

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

A. As a combination natural gas and electric utility, over the next few years capital will be required for customer growth as well as necessary maintenance and replacements of our natural gas systems, investment in generation upgrades, and transmission and distribution facilities for the electric utility business.

We have been making significant capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. Utility capital expenditures were $271.2 million for 2012.

The amount of capital expenditures planned for 2013-2014 is approximately $526 million, and over a five year period ending December 31, 2017 is approximately $1.3 billion. These significant increases in capital investment continue to be the driving force behind Avista's need for additional rate relief in each of its jurisdictions, including such major projects as the replacement of Avista's customer information system and replacement of its Aldyl-A natural gas distribution lines, as discussed further by Company witness Morris and others. Additionally, these planned capital investments are substantial given the relative size of the Company's total rate base, which as of May 31, 2013, was $2.3 billion.

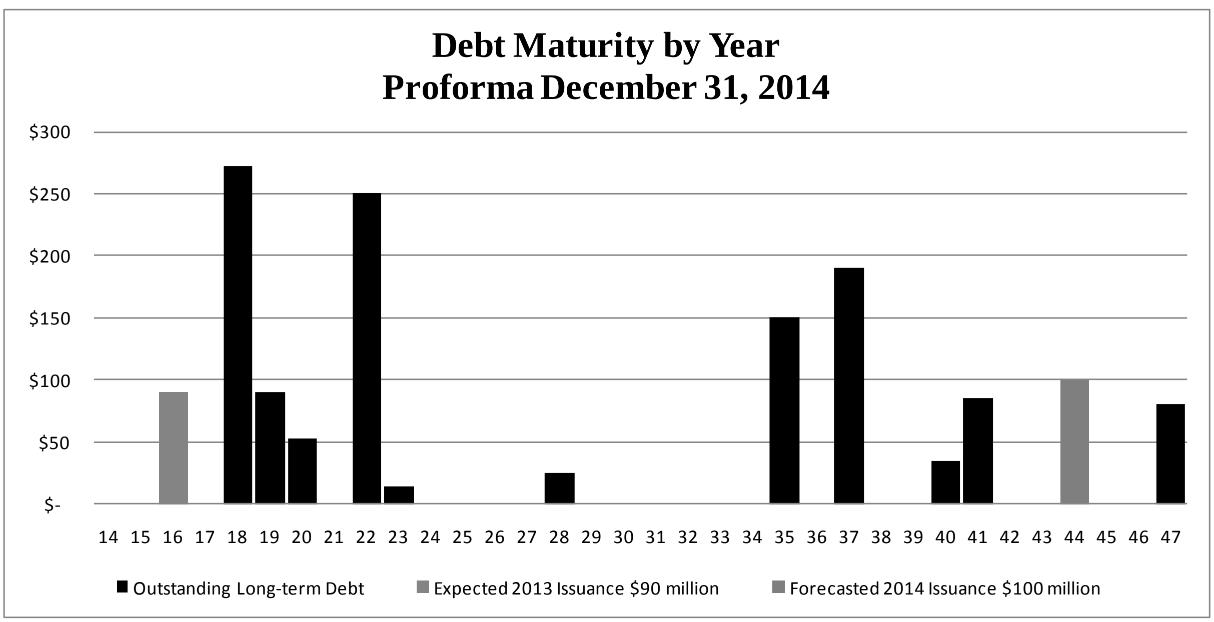
Q. What are the Company's near-term plans related to its debt?

A. The Company finances its rate base assets with long term debt and equity. As such, from time to time, we need to access long-term capital markets in order to finance these long-term assets as well as fund maturing debt.

In August 2013, the Company expects to execute a $90 million three-year loan agreement, at a fixed rate of 0.84 percent. The Company has $50.0 million of 1.68 percent First Mortgage Bonds that mature in December 2013. Additionally, the Company is forecasting the issuance of $100 million of 5.50 percent First Mortgage bonds in September 2014.

Illustration No. 4 below shows the amount of debt maturities by year including the maturity date of the forecasted long-term debt issuances through December 2014:

Illustration No. 4:



V. CAPITAL STRUCTURE

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

A. The proportionate shares of Avista Corp.'s pro forma capital structure are 50.0 percent common equity, and 50.0 percent long-term debt as shown on page 2 of Exhibit No. 201. Additional details related to Avista Corp.'s capital structure are included on pages 3 through 4.

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

A. Avista continuously monitors the common equity ratio of its capital structure, and assesses the need to issue additional common equity in order to maintain a capital structure that is appropriate for our business. In 2012, we issued $29.1 million of equity and in 2011, we issued $26.5 million of equity. We are planning to issue up to $50 million of common stock in 2013, in order to maintain our capital structure at an appropriate level for our business. It is important to the rating agencies and investors for Avista to maintain a balanced debt/equity ratio in order to minimize the risk of default on required debt interest payments.

In Dr. Avera's testimony he concludes that the 50.0 percent common equity ratio is reasonable based on the following:

- The common equity ratio implied by Avista's capital structure falls within the range of capitalizations maintained by the proxy groups of utilities based on data at year-end and near-term expectations;
- Avista's 50% common equity ratio falls below the 54.4% average for the proxy group of gas utilities at year-end 2012. Similarly, Avista's requested equity ratio falls short of the 54.3% equity ratio based on Value Line's expectations for these utilities over the near-term. Because a capitalization that contains relatively more debt leverage implies greater financial risk, it also implies a higher required rate of return to compensate investors for bearing additional uncertainty. (Avera Testimony, p. 11, ll. 6 to 14).

VI. COST OF DEBT

Q. How have you determined the cost of debt?

A. Cost of total long-term debt in the Company's proposed capital structure includes actual and forecasted weighted average long-term debt as shown on page 2 of Exhibit No. 201. The size and mix of debt changes over time based upon the actual financing completed. We have made certain pro forma adjustments to update the debt cost through December 31, 2014. Pro forma adjustments to total long-term debt reflect the issuance of new debt for the pro forma period.

We are anticipating the cost of debt to decrease to 5.55% by December 31, 2014, from 5.90% as of December 31, 2012. This decrease is primarily due to the 2013 issuance of $90 million through a three year loan agreement, at a fixed rate of 0.84 percent, which is being issued, in part, to refinance the Company's $50.0 million of 1.68 percent First Mortgage Bonds that mature in December 2013.

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 a 10.1% return on common equity (ROE), which falls in 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 with an ROE range of 9.9% to 10.9% and 10.04% to 11.04% (after accounting for the impact of common equity flotation costs).

Q. Dr. Avera suggests an ROE range of 10.04 to 11.04%. Why is Avista requesting an ROE in the lower end of the range?

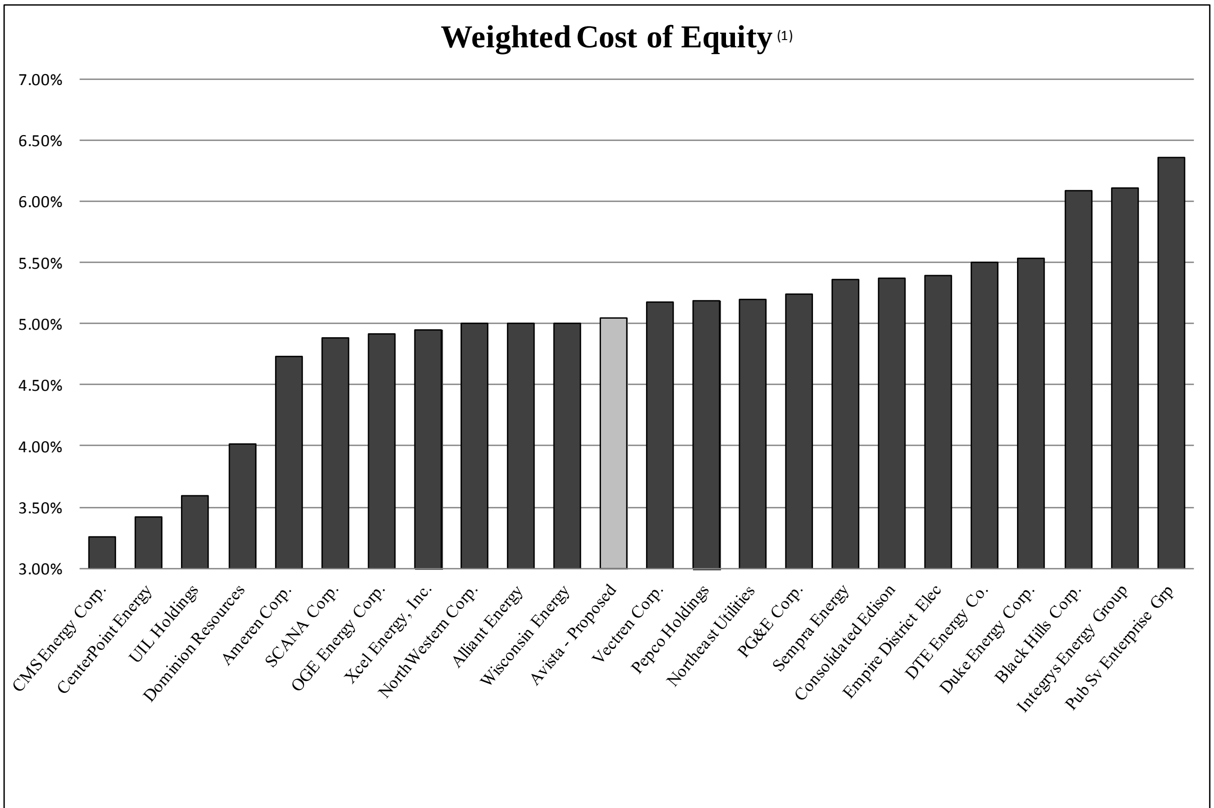
A. The Company is proposing a 10.1% return on common equity (ROE), at the lower end of Dr. Avera's range, primarily to mitigate the overall requested rate increase to customers. In his testimony Dr. Avera states:

> "Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, I concluded that Avista's requested ROE of 10.1% percent is reasonable and, if anything, understated. Based on my evaluation, I determined that:
>
> - Because Avista's requested ROE of 10.1% percent falls in the bottom end of my recommended range, it represents a conservative estimate of investors' required rate of return;
> - The reasonableness of a 10.1% minimum ROE for Avista is also reinforced by the lack of a WNA [weather normalization adjustment] in Oregon for Avista, and the fact that, unlike many gas utilities, Avista does not benefit from a decoupling mechanism that provides recovery of fixed costs as customer usage changes. (Avera Testimony, p. 9, ll. 11 through p. 10, ll. 6).

Q. How does Avista's requested Weighted Cost of Equity compare to Dr. Avera's Utility Proxy Group's Weighted Cost of Equity?

A. With regard to the Weighted Cost of Equity (ROE x equity layer), the following graph shows the weighted cost of equity (WCOE) for the Utility Proxy Group in Dr. Avera's testimony. The WCOE represents the authorized ROE by state commissions for the most current rate cases per Dr. Avera's Exhibit No. 301, Schedule WEA-13, page 2, multiplied by the common equity ratio per 2013 Value Line Investment Surveys as shown on Exhibit No. 301, Schedule WEA-6, page 2. The Illustration below shows that the majority of WCOEs are at 5.0% or above.

Illustration No. 5:



(1) Source - Dr. Avera Proxy Group, Exhibit 301 (Schedule WEA-6,page 2) (The Value Line Investment Survey (May24, Jun. 21 & Aug. 2, 2013) times Schedule WEA-13, page 2) (AUS Monthly Utility Report (July 2013))

As this illustration demonstrates, Avista's weighted cost of equity of 5.05% (10.1% ROE x 50% equity layer) is in the middle range of Dr. Avera's Utility Proxy Group.

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 illustration shows the capital structure and cost components proposed by the Company.

<u>Illustration No. 6:</u>

AVISTA CORPORATION
Proposed Cost of Capital

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,433,000,000	50.00%	5.55%	2.78%
Common Equity	1,412,212,167	50.00%	10.10%	5.05%
Total	$2,845,212,167	100.00%		**7.83%**

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

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

MARK T. THIES
Exhibit No. 201

Financial Overview, Capital Structure and Overall Rate of Return

AVISTA CORPORATION
Long-term Securities Credit Ratings

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

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

AVISTA CORPORATION
Proposed Cost of Capital
December 31, 2014

	Amount	Percent of Total Capital		Cost		Component
Total Debt	$1,433,000,000	50.00%	(1)	5.55%		2.78%
Common Equity	1,412,212,167	50.00%	(1)	10.10%	(2)	5.05%
Total	$2,845,212,167	100.00%				**7.83%**

AVISTA CORPORATION
Cost of Capital as of
December 31, 2012

	Amount	Percent of Total Capital	Cost	Component
Total Debt	$1,293,000,000	50.23%	5.90%	2.96%
Common Equity	1,280,966,489	49.77%	10.10%	5.03%
Total	$2,573,966,489	100.00%		**7.99%**

1 The Company's forecasted percentage of debt and equity is 50.4% and 49.6%, respectively. Consistent with prior regulatory filings the Company is filing a capital structure of 50% equity and 50% total debt.

2 Proposed Return on Common Equity - See Avera testimony

AVISTA CORPORATION
Cost of Long-Term Debt Detail - Oregon
December 31, 2014

Line No.	Description	Coupon Rate	Maturity Date	Settlement Date	Principal Amount	Issuance Costs	SWAP Loss/(Gain)	Discount (Premium)	Loss/Reacq Expenses	Net Proceeds	Yield to Maturity	Outstanding 12/31/2014	Effective Cost	Years to Maturity	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)	(h)	(i)	(j)	(k)	(l)		
1	FMBS - SERIES A	7.530%	5/5/2023	5/6/1993	5,500,000	42,712	-	-	963,011	4,494,277	9.359%	5,500,000	514,744	8.4 years	1
2	FMBS - SERIES A	7.540%	5/5/2023	5/7/1993	1,000,000	7,766	-	-	175,412	816,822	9.375%	1,000,000	93,747	8.4 years	2
3	FMBS - SERIES A	7.390%	5/11/2018	5/11/1993	7,000,000	54,364	-	-	1,227,883	5,717,753	9.287%	7,000,000	650,114	3.4 years	3
4	FMBS - SERIES A	7.450%	6/11/2018	6/9/1993	15,500,000	120,377	-	50,220	2,140,440	13,188,963	8.953%	15,500,000	1,387,715	3.5 years	4
5	FMBS - SERIES A	7.180%	8/11/2023	8/12/1993	7,000,000	54,364	-	-	-	6,945,636	7.244%	7,000,000	507,064	8.7 years	5
6	TRUST PREFERRED	1.442% [1]	6/1/2037	6/3/1997	40,000,000	1,296,086	-	-	(1,769,125)	40,473,039	1.403%	40,000,000	561,163	22.5 years	6
7	FMBS - SERIES C	6.370%	6/19/2028	6/19/1998	25,000,000	158,304	-	-	188,649	24,653,047	6.475%	25,000,000	1,618,863	13.5 years	7
8	FMBS - 5.45% SERIES	5.450%	12/1/2019	11/18/2004	90,000,000	1,192,681	-	239,400	-	88,567,919	5.608%	90,000,000	5,047,001	5 years	8
9	FMBS - 6.25%	6.250%	12/1/2035	11/17/2005	150,000,000	1,812,935	(4,445,000)	367,500	-	152,264,565	6.139%	150,000,000	9,208,605	21 years	9
10	FMBS - 5.70%	5.700%	7/1/2037	12/15/2006	150,000,000	4,702,304	3,738,000	222,000	-	141,337,696	6.120%	150,000,000	9,179,674	22.6 years	10
11	FMBS - 5.95% SERIES	5.950%	5/1/2018	4/2/2008	250,000,000	2,246,419	16,395,000	835,000	-	230,523,581	7.041%	250,000,000	17,603,224	3.4 years	11
12	FMBS - 5.125% SERIES	5.125%	4/1/2022	9/22/2009	250,000,000	2,284,788	(10,776,222)	575,000	2,875,817	255,040,618	4.907%	250,000,000	12,268,615	7.3 years	12
13	FMBS - 3.89% SERIES	3.890%	12/20/2020	12/20/2010	52,000,000	383,338	-	-	6,273,664	45,342,997	5.578%	52,000,000	2,900,325	6 years	13
14	FMBS - 5.55% SERIES	5.550%	12/20/2040	12/20/2010	35,000,000	258,834	-	-	5,263,822	29,477,345	6.788%	35,000,000	2,375,887	26 years	14
15	FMBS - 4.45% SERIES	4.450%	12/14/2041	12/14/2011	85,000,000	692,722	10,557,000	-	-	73,750,278	5.340%	85,000,000	4,538,863	27 years	15
16	FMBS - 4.23% SERIES	4.230%	11/29/2047	11/30/2012	80,000,000	725,635	18,546,870	-	105,020	60,622,475	5.868%	80,000,000	4,694,097	32.9 years	16
17	FMBS - 0.84% SERIES	0.840%	9/1/2016	9/1/2013	90,000,000	500,000 [2]	(2,900,680)			92,400,678	-0.048%	90,000,000	(43,549)	1.8 years	17
18	Forecasted Debt Issuance [3]	5.500% [4]	9/15/2044	9/15/2014	100,000,000	1,000,000 [2]				98,999,998	5.569%	100,000,000	5,568,962	29.8 years	18
19												1,433,000,000	78,675,117		19
20															20
21	Repurchase [5]	7.74%	12/31/2017	6/30/2006	6,875,000				483,582	6,391,418	8.721%	[6]	70,127	3 years	21
22	Repurchase [5]	8.17%	6/30/2015	6/30/2005	26,000,000				1,700,371	24,299,629	9.184%	[6]	267,096	0.5 years	22
23	Repurchase [5]	5.72%	3/1/2034	12/30/2009	17,000,000				1,916,297	15,083,703	6.661%	[6]	159,446	19.3 years	23
24	Repurchase [5]	6.55%	10/1/2032	12/31/2008	66,700,000				3,709,174	62,990,826	7.034%	[6]	324,360	17.8 years	24
25			**OREGON TOTAL DEBT OUTSTANDING AND COST OF DEBT AT December 31, 2014**									1,433,000,000	79,496,146		25
26															26
27								**Adjusted Weighted Average Cost of Debt**			**5.55%**				27
28															28
29															29

30 [1] Average Monthly Average Rate over a thirteen month period (see page four of this Exhibit) 30
31 [2] The issuance costs are estimated 31
32 [3] Forecasted issuance pursuant to the Company's internal forecast 32
33 [4] Forecasted Rates are based on forward rates from Thomson Reuters analysis tools plus an estimated credit spread 33
[5] Coupon Rate at the time of repurchase
[6] Calculated using the Internal Rate of Return method

AVISTA CORPORATION
Cost of Long-Term Variable Rate
December 31, 2014

Line		Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Avg of
2	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
3	TRUST PREFERRED*	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	**$ 40,000,000**
4															
5	Number of Days in Month	31	31	28	31	30	31	30	31	31	30	31	30	31	
6	Monthly Borrowing Rate**	1.18%	1.18%	1.18%	1.25%	1.25%	1.25%	1.34%	1.34%	1.34%	1.41%	1.41%	1.41%	1.51%	
7	Interest Expense	$ 40,472	$ 40,472	$ 36,556	$ 42,918	$ 41,533	$ 42,918	$ 44,633	$ 46,121	$ 46,121	$ 47,133	$ 48,704	$ 47,133	$ 51,942	**$ 576,658**
8															

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

10 **Forecasted Rates are based on forward rates from Thomson Reuters analysis tools plus the 87.5 basis points pursuant to the debt agreement. Average borrowing rate 1.44%

11

12

13

AVISTA CORPORATION

Long-term Securities Credit Ratings

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

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December 31, 2014

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13	FMBS - 3.89% SERIES	3.890%	12/20/2020	12/20/2010	52,000,000	383,338	-	-	6,273,664	45,342,997	5.578%	52,000,000	2,900,325	6 years	13
14	FMBS - 5.55% SERIES	5.550%	12/20/2040	12/20/2010	35,000,000	258,834	-	-	5,263,822	29,477,345	6.788%	35,000,000	2,375,887	26 years	14
15	FMBS - 4.45% SERIES	4.450%	12/14/2041	12/14/2011	85,000,000	692,722	10,557,000	-	-	73,750,278	5.340%	85,000,000	4,538,863	27 years	15
16	FMBS - 4.23% SERIES	4.230%	11/29/2047	11/30/2012	80,000,000	725,635	18,546,870	-	105,020	60,622,475	5.868%	80,000,000	4,694,097	32.9 years	16
17	FMBS - 0.84% SERIES	0.840%	9/1/2016	9/1/2013	90,000,000	500,000 [2]	(2,900,680)			92,400,678	-0.048%	90,000,000	(43,549)	1.8 years	17
18	Forecasted Debt Issuance [3]	5.500% [4]	9/15/2044	9/15/2014	100,000,000	1,000,000 [2]				98,999,998	5.569%	100,000,000	5,568,962	29.8 years	18
19												1,433,000,000	78,675,117		19
20															20
21	Repurchase [5]	7.74%	12/31/2017	6/30/2006	6,875,000				483,582	6,391,418	8.721%	[6]	70,127	3 years	21
22	Repurchase [5]	8.17%	6/30/2015	6/30/2005	26,000,000				1,700,371	24,299,629	9.184%	[6]	267,096	0.5 years	22
23	Repurchase [5]	5.72%	3/1/2034	12/30/2009	17,000,000				1,916,297	15,083,703	6.661%	[6]	159,446	19.3 years	23
24	Repurchase [5]	6.55%	10/1/2032	12/31/2008	66,700,000				3,709,174	62,990,826	7.034%	[6]	324,360	17.8 years	24
25		**OREGON TOTAL DEBT OUTSTANDING AND COST OF DEBT AT December 31, 2014**										1,433,000,000	79,496,146		25
26															26
27								**Adjusted Weighted Average Cost of Debt**			**5.55%**				27
28															28
29															29

30 [1] Average Monthly Average Rate over a thirteen month period (see page four of this Exhibit) 30
31 [2] The issuance costs are estimated 31
32 [3] Forecasted issuance pursuant to the Company's internal forecast 32
33 [4] Forecasted Rates are based on forward rates from Thomson Reuters analysis tools plus an estimated credit spread 33
[5] Coupon Rate at the time of repurchase
[6] Calculated using the Internal Rate of Return method

AVISTA CORPORATION
Cost of Long-Term Variable Rate
December 31, 2014

	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Avg of
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
TRUST PREFERRED*	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	**$ 40,000,000**
Number of Days in Month	31	31	28	31	30	31	30	31	31	30	31	30	31	
Monthly Borrowing Rate**	1.18%	1.18%	1.18%	1.25%	1.25%	1.25%	1.34%	1.34%	1.34%	1.41%	1.41%	1.41%	1.51%	
Interest Expense	$ 40,472	$ 40,472	$ 36,556	$ 42,918	$ 41,533	$ 42,918	$ 44,633	$ 46,121	$ 46,121	$ 47,133	$ 48,704	$ 47,133	$ 51,942	**$ 576,658**

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

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

Average borrowing rate 1.44%

Exhibit No. 300
Avera

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF WILLIAM E. AVERA

REPRESENTING 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 Exhibit No. 303.

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 10.1% fair rate of return on equity ("ROE") that Avista Corp. ("Avista" or "the Company") is requesting for its jurisdictional gas utility operations. In addition, I also examined the reasonableness of the Company's requested capital structure, considering both the specific risks faced by Avista and other industry guidelines.

Q. Please summarize the 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 the issues relevant to investors' required return for Avista, and they form the basis of my analyses and conclusions.

Q. How is your testimony organized?

A. After first summarizing my conclusions and recommendations, I review current conditions in the capital markets and their implications in evaluating a fair ROE for Avista. With this as a background, I conducted well-accepted quantitative analyses to estimate the current cost of equity for separate reference groups of gas and combination utilities. These included the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on allowed ROEs for gas and electric utilities. Based on the cost of equity estimates indicated by my analyses, the reasonableness of Avista's requested 10.1% ROE was evaluated taking into account the specific risks for its jurisdictional utility operations in Oregon, Avista's requirements for financial strength that provides benefits to customers, as well as flotation costs, which are properly considered in setting a fair ROE.

Finally, I tested my conclusions based on the results of alternative ROE benchmarks for my proxy groups, including applications of the traditional Capital Asset Pricing Model ("CAPM") and reference to expected rates of return and allowed ROEs. Further, I corroborate my utility quantitative analyses by applying the DCF model to a group of low risk non-utility firms.

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

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility commensurate with other investments of comparable risk, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

II. RETURN ON EQUITY FOR AVISTA

Q. What is the purpose of this section?

A. This section presents my conclusions regarding the reasonableness of the 10.1% ROE requested by Avista for its jurisdictional gas utility operations. This section also

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

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

A. Importance of Financial Strength

Q. What role does OPUC regulation play in supporting investor confidence?

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

Q. Does Avista anticipate the need for capital going forward?

A. Yes. 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. Company-wide utility capital additions are expected to total approximately $526 million for 2013-2014 alone, and approximately $1.3 billion through 2017. These planned capital additions are far from routine, given that Avista's total rate base amounted to $2.3 billion at May 31, 2013.

Significant increases in capital investment continue to be the driving force behind Avista's need for additional rate relief in each of its jurisdictions, including such major projects as the replacement of Avista's customer information system and replacement of its Aldyl-A natural gas distribution lines, as discussed further by Company witnesses Mr. Morris and others. 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.

Q. What other considerations are relevant in determining a reasonable ROE for Avista's jurisdictional gas utility operations?

A. Unlike many gas utilities, Avista does not have a weather normalization adjustment ("WNA") 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, all of the ten LDCs in the proxy group used to estimate the cost of equity have some form of weather mitigant, including decoupling mechanisms, 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:

> Unseasonable warmer or colder weather can lead to volatility in results. By using these rate mechanisms, natural gas utilities are less subject to swings in profitability due to unforeseen weather conditions.[3]

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.

Q. Are there other factors that distinguish the risks of Avista's gas utility operations from other gas utilities in Oregon?

A. Yes. In evaluating a reasonable rate of return on equity, it is also important to

[3] The Value Line Investment Survey at 547 (Sep. 10, 2010).

note that, unlike some utilities in Oregon, Avista does not benefit from elasticity or decoupling mechanisms that insulate utility margins from declining usage. Avista's jurisdictional gas utility operations have experienced declines in customer usage that have translated into reduced margins. Moreover, customer load growth in Avista's Oregon jurisdictional gas utility operations continues to be weak and is not expected to strengthen in the near future.

Q. What does this imply with respect to Avista's risks relative to other gas utilities in general?

A. In contrast to Avista's situation in Oregon, adjustment mechanisms and trackers, including decoupling, have been increasingly prevalent in the utility industry in recent years. Reflective of this industry trend, the companies included in the proxy groups referenced in my analyses operate under a variety of cost adjustment and decoupling mechanisms. For example, Regulatory Research Associates recently reported that Atmos Energy Corporation, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, and Southwest Gas Corporation all have operating subsidiaries that operate under some form of decoupling mechanism that accounts for the impact of various factors affecting sales volumes and revenues.[4] In addition, AGL Resources and NiSource, Inc. have operating subsidiaries that operate under Straight-Fixed-Variable rate design, which has a similar impact.

As a result, Avista's continued exposure to the uncertainties associated with the impact

[4] Regulatory Research Associates, "Adjustment Clauses and Rate Riders," *Regulatory Focus* (March 21, 2012).

of price elasticity and other fluctuations in customer usage implies a greater level of risk than is faced by other utilities, including other utilities operating in Oregon and the firms in my proxy groups.

B. Recommended ROE

Q. What are your findings regarding the fair ROE for Avista's gas utility operations?

A. Based on the adjusted cost of equity estimates presented on Exhibit No. 301, Schedule WEA-1, page 1, I recommend that Avista be authorized an ROE in the range of 9.90% to 10.90%, or 10.04% to 11.04% after considering an adjustment for flotation costs.

Q. Please summarize the results of the quantitative analyses on which your recommended ROE range was based.

A. In order to reflect the risks and prospects associated with Avista's jurisdictional utility operations, my analyses focused on two proxy groups of firms with gas utility operations. The cost of common equity estimates produced by the DCF, ECAPM, and risk premium analyses described subsequently are presented on Exhibit No. 301, Schedule WEA-1, page 2, and summarized below:

- Taken together, I concluded that the DCF, ECAPM, and risk premium results suggested an overall cost of equity range of 9.90% to 10.9%;
  - Considering the relative merits of the alternative growth rates, I determined that the DCF results implied an ROE range on the order of 9.2% to 10.2%;
  - The forward-looking ECAPM estimates suggested an ROE on the order of 10.3% to 11.3%;
  - The utility risk premium approach implies an ROE estimate of 10.2% to 11.1% for gas utilities;
- Adding a minimal flotation cost adjustment of 14 basis points resulted in an adjusted ROE range of 10.04% to 11.04%.

Q. What did the results of alternative ROE benchmarks indicate with respect to your recommended ROEs?

A. The results of the traditional CAPM analyses, a review of expected earned rates of return and authorized returns for gas utilities, as well as DCF results for a low risk group of non-utility firms,[5] are shown on Exhibit No. 301, Schedule WEA-1, page 3, and summarized in Exhibit No. 302, Table WEA-7, which is reproduced below:

TABLE WEA-7
SUMMARY OF ALTERNATIVE ROE BENCHMARKS

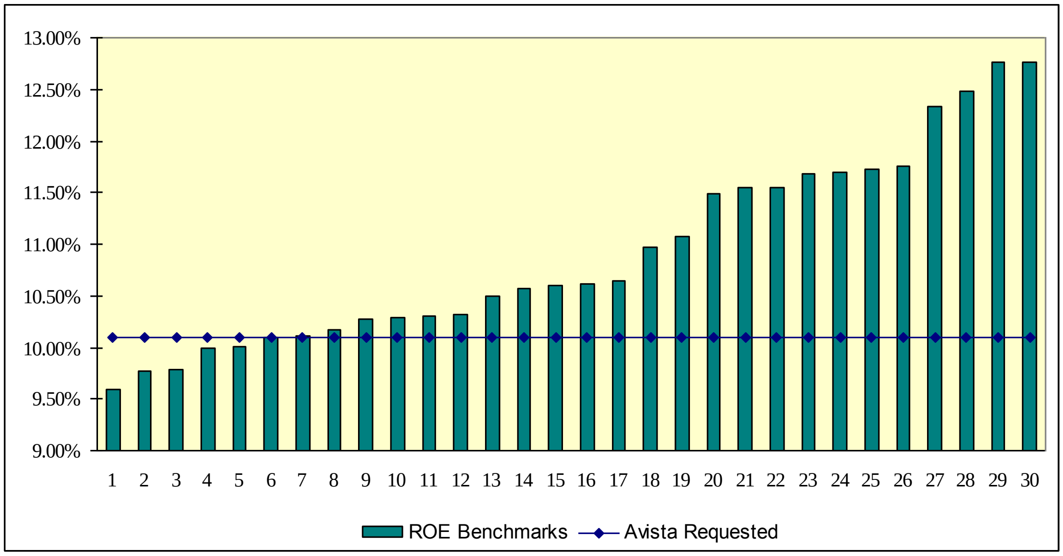
	Gas Group		Combination Group	
	Average	Midpoint	Average	Midpoint
CAPM - 2013 Yield				
Unadjusted	9.59% [1]	9.78% [3]	9.77% [2]	9.99% [4]
Size Adjusted	11.07% [19]	10.57% [14]	10.64% [17]	10.3% [11]
CAPM - Projected Yield				
Unadjusted	10.01% [5]	10.17% [8]	10.10% [6]	10.29% [10]
Size Adjusted	11.49% [20]	11.68% [23]	10.968% [18]	10.60% [15]
Expected Earnings	11.55% [21]	12.49% [28]	10.49% [13]	12.33% [27]
Allowed ROE	10.32% [12]	10.61% [16]	10.27% [9]	10.12% [7]
Non-Utility DCF				
Value Line	11.56% [22]	11.73% [25]		
IBES	11.69% [24]	12.76% [29]		
Zacks	11.75% [26]	12.77% [30]		

Note: Footnotes correspond to rank order in the subsequent figure.

[5] As discussed subsequently, the average risk measures for group of non-utility firms indicate less investment risk that investors would associate with Avista or the proxy groups of utilities.

Figure WEA-1, below, compares the alternative benchmark results presented in the table above with Avista's 10.1% ROE request:

FIGURE WEA-1
ALTERNATIVE ROE BENCHMARKS VS. AVISTA ROE REQUEST



As illustrated in Figure WEA-1, the tests of reasonableness presented in my testimony confirm that Avista's 10.1% requested ROE falls in the reasonable range to maintain Avista's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

Q. What did you conclude with respect to the reasonableness of Avista's requested ROE?

A. Considering investors' expectations for capital markets and the need to support financial integrity and fund crucial capital investment even under adverse circumstances, I concluded that Avista's requested ROE of 10.1% percent is reasonable and, if anything, understated. Based on my evaluation, I determined that:

- Because Avista's requested ROE of 10.1% percent falls in the bottom end of my recommended range, it represents a conservative estimate of investors' required rate of return;

- The reasonableness of a 10.1% minimum ROE for Avista is also reinforced by the lack of a WNA in Oregon for Avista, and the fact that, unlike many gas utilities, Avista does not benefit from a decoupling mechanism that provides recovery of fixed costs as customer usage changes.

Q. Does this 10.1% ROE represent a reasonable cost for Avista's customers to pay?

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

Apart from the results of the quantitative methods, it is crucial to recognize the importance of maintaining a strong financial position so that Avista remains prepared to respond to unforeseen events that may materialize in the future. While this imperative is reinforced by current capital market conditions, it extends well beyond the financial markets and includes the Company's ability to absorb potential shocks associated with natural disasters such as catastrophic storms and unexpected events. Recent challenges in the capital markets and ongoing economic uncertainties highlight the benefits of supporting Avista's financial standing to ensure that the Company can attract the capital needed to secure reliable service at a reasonable cost for customers.

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

A. Based on my evaluation, I concluded that a common equity ratio of 50% represents a reasonable capitalization for Avista. This conclusion was based on the following findings:

- The common equity ratio implied by Avista's capital structure falls within the range of capitalizations maintained by the proxy groups of utilities based on data at year-end and near-term expectations;
- Avista's 50% common equity ratio falls below the 54.4% average for the proxy group of gas utilities at year-end 2012. Similarly, Avista's requested equity ratio falls short of the 54.3% equity ratio based on Value Line's expectations for these utilities over the near-term. Because a capitalization that contains relatively more debt leverage implies greater financial risk, it also implies a higher required rate of return to compensate investors for bearing additional uncertainty.

III. OUTLOOK FOR CAPITAL COSTS

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

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

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

A. The yields on utility bonds are at their lowest levels in modern history. Figure WEA-2, below, compares the current yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

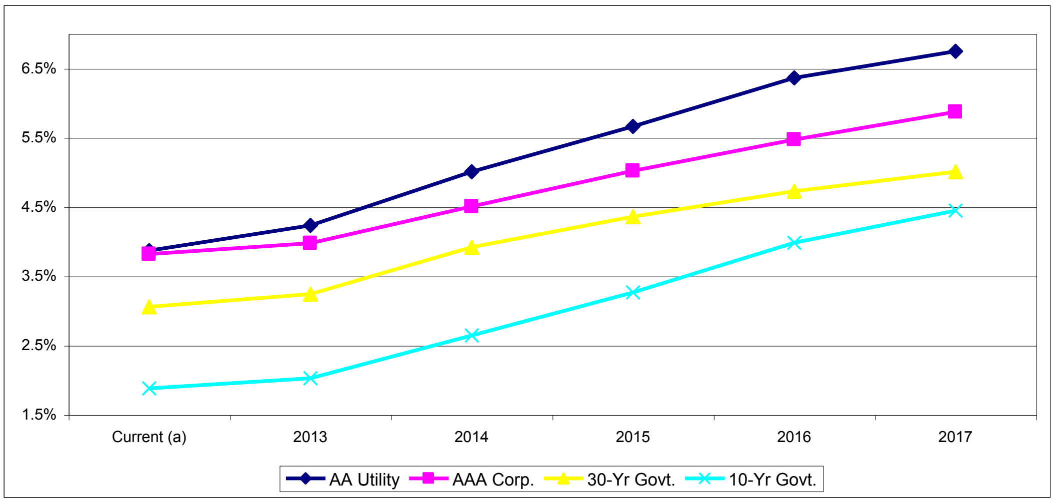
FIGURE WEA-2
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience.

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

A. No. Investors do not anticipate that these low interest rates will continue into the future. It is widely anticipated that as the economy stabilizes and resumes a more robust pattern of growth, long-term capital costs will increase significantly from present levels. Figure WEA-3 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE WEA-3
INTEREST RATE TRENDS



(a) Based on monthly average bond yields for the six-month period Dec. 2012 - May 2013 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.

Sources:
Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013)
IHS Global Insight, U.S. Economic Outlook at 25 (May 2013)
Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013)
Blue Chip Financial Forecasts, Vol. 32, No. 6 (Jun. 1, 2013)

These forecasting services are highly regarded and widely referenced, with FERC incorporating forecasts from IHS Global Insight and the EIA in its preferred DCF model for natural gas pipelines. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2014-2017 period than it is currently.

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

A. No. While the Federal Reserve continues to express support for maintaining current stimulus policies, it has also has begun to map out a strategy for reducing its bond-buying program based on conditions for employment and inflation. The Wall Street Journal noted the close link between investors' required returns in the capital markets and the Federal Reserve's policy pronouncements:

> Investors are bracing for a stormy summer, as steady asset-price gains fueled by bottomless central-bank liquidity have given way to sharp swings jolting stocks, currencies, and commodities alike. … Since Federal Reserve meeting minutes released May 22 indicated the central bank would consider as soon as this month cutting back on bond purchases, the Dow Jones Industrial Average has swung more that 200 points in a day six times.[6]

Similarly, Value Line also highlighted the impact on investors of ongoing uncertainties over a potential revision of Federal Reserve's stimulus policies:

> Investors are becoming more wary, as they speculate on whether or not the Fed is about to shift policy gears. With the economy in a holding pattern over here, with things in flux overseas, and with the central bank unclear regarding its intentions, the recent rise in volatility on Wall Street may be here to stay for a while.[7]

The Wall Street Journal observed that the plan to reduce bond purchases "is of intense interest in the financial markets."[8] More recently, the International Monetary Fund noted that, "A lack of Fed clarity could cause a major spike in borrowing costs that could cause severe damage to the U.S. recovery and send destructive shockwaves around the global economy,"

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[6] Scaggs, Alexandra, "Forecast Calls for Volatility," *Abreast of the Market*, The Wall Street Journal (Jun. 9, 2013).
[7] The Value Line Investment Survey, *Selection and Opinion* at 905 (Jun. 14, 2013).
[8] Hilsenrath, Jon, "Fed Maps Exit from Stimulus, *Wall Street Journal* at A1 (May 11, 2013).

adding that, "A smooth and gradual upward shift in the yield curve might be difficult to engineer, and there could be periods of higher volatility when longer yields jump sharply, -- as resent events suggest."[9] These discussions highlight concerns for investors and supports expectations for higher interest rates as the economy and labor markets continue to recover.

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

A. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets. As a result, current capital costs are not representative of what is likely to prevail over the near-term future, with this conclusion being demonstrated by comparisons to the historical record and independent forecasts. Recognized economic forecasting services project that long-term capital costs will increase from present levels. To address the reality of current capital markets, the OPUC should consider near-term forecasts for public utility bond yields in evaluating the reasonableness of individual cost of equity estimates and in selecting a reasonable ROE for Avista from within the zone of reasonableness.

Q. Does Avista's ability to seek an increase in its allowed ROE through a future rate filing eliminate the need to consider expectations for higher capital costs?

A. No. The fact that Avista can request a higher ROE at some future time does not imply that the OPUC can ignore the impact that exceptionally low interest rates have on quantitative estimates of the cost of equity, or the fact that yields are expected to increase

[9] Talley, Ian, "IMF Urges 'Improved' U.S. Fed Policy Transparency as It Mulls Easy Money Exit," *The Wall Street Journal* (July 26, 2013).

significantly. Given the inherent lag in rate proceedings, a failure to consider near-term expectations for higher capital costs will render any new ROE insufficient by the time it becomes effective. Considering the costs and burdens inherent in any rate filing, it is simply not practical or desirable to promote an outcome of continuous rate filings in an effort to keep pace with ongoing increases in capital costs. The OPUC has the flexibility to consider a wide variety of evidence in this evaluation, including the DCF range, the results of other methods, and ongoing capital market trends that impact shareholders' required rate of return. Interest rate projections are a key indicator that has direct relevance in evaluating a fair ROE, and deliberately ignoring expected changes in capital market conditions will deny Avista the opportunity to earn a fair ROE during the time that rates are in effect.

IV. COMPARABLE RISK PROXY GROUPS

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

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

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

A. In order to reflect the risks and prospects associated with Avista's jurisdictional gas utility operations, I examined quantitative estimates of investors' required ROE for a group of natural gas utilities, consisting of ten publicly traded firms included in Value Line's Natural Gas Utility industry.[10] I refer to these utilities as the "Gas Group."

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

A. My analyses also considered those utilities followed by Value Line with both electric and gas utility operations. In addition, I excluded three firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because of current involvement in a major merger or acquisition,[11] as well as one firm (Exelon Corporation) that recently cut its dividend payments These criteria resulted in a proxy group composed of twenty-five companies, which I will refer to as the "Combination Utility Group."

Q. How do the overall risks of your two proxy groups compare with Avista?

A. Table WEA-1 compares the average corporate credit rating for Gas and Combination Groups with Avista, as well as three key quality rankings published by Value Line, which are also widely referenced by investors:

[10] I excluded one firm – UGI Corporation – that was included in Value Line's Natural Gas Utility Industry because it is primarily engaged in propane sales and marketing.
[11] Entergy Corporation, NV Energy, Inc., and TECO Energy, Inc.

TABLE WEA-1
COMPARISON OF RISK INDICATORS

Proxy Group	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Gas Utility	A-	2	B++	0.68
Combination Utility	BBB+	2	B++	0.70
Avista	BBB	2	A	0.70

Q. Do these indicators provide objective evidence to evaluate investors' risk perceptions?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Investment restrictions tied to credit ratings continue to influence capital flows, and credit ratings are widely cited in the investment community and referenced by investors, and also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

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

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

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

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[12]

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

Q. What does this comparison indicate regarding investors' assessment of the equity risks associated with your utility proxy groups?

A. As displayed in Table WEA-1, Avista is assigned a corporate credit rating of "BBB" by S&P, with the average corporate credit ratings for the Gas and Combination Groups indicating less risk. The average Safety Rank and beta values for the two utility groups are essentially identical to Avista, while the Company's higher Financial Strength Rating indicates slightly less risk than for the group of utilities.

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

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

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

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

A. The capital structure used to compute the overall rate of return for Avista includes 50.0% common equity.

Q. How can the Company's requested capital structure be evaluated?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. What average capitalizations are maintained by the Combination and Gas Groups?

A. As shown on page 1 of Exhibit No. 301, Schedule 2, for the firms in the Gas Group, common equity ratios at December 31, 2012 averaged 54.4% of long-term capital, with Value Line expecting an average common equity ratio of 54.3% for its three-to-five year forecast horizon. Meanwhile, for the firms in the Combination Group, common equity ratios averaged 48.4% in 2012, with Value Line projecting this to increase to 50.2% (page 2 of Exhibit No. 301, Schedule 2). Thus, Avista's common equity ratio is within the range maintained by the Combination Group, while indicating somewhat greater financial risk than investors would associate with the Gas Group.

Based on my evaluation, I concluded that Avista's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return.

V. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

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

A. Economic Standards

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

A. The return on common equity is the cost of inducing and retaining 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. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

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

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

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

$$k_i = R_f + RP_i$$

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

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

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

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

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

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

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

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

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

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

C. Discounted Cash Flow Analyses

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

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

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

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

That is, the cost of common equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

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

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[13]

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

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

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

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

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

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

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

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

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

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second 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 common equity.

Q. How was the dividend yield for the Gas Group determined?

A. For D_1, I used estimates of dividends to be paid by each of these utilities over the next 12 months, obtained from Value Line. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Gas Group are presented on Exhibit No. 301, Schedule 3. As shown on page 1, dividend yields for the firms in the Gas Group ranged from 2.7% to 4.3%.

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

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

Q. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to distort historical growth measures, they are neither representative of long-term growth for the utility industry nor the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

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

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

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 per share ("EPS"), 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, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS"). Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that dividend growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

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

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

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

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

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[14]

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

A. The earnings growth projections for each of the firms in the Gas Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on page 2 of Exhibit No. 301, Schedule 3. [15]

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[14] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).
[15] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

Q. Some argue that analysts' assessments of growth rates are biased. Do you believe these projections are appropriate for estimating investors' required return using the DCF model?

A. Yes, I do. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

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

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[16]

Q. Have other regulators recognized that consensus growth rate estimates are an important and meaningful guide to investors' expectations?

A. Yes. FERC has expressed a clear preference for projected EPS growth rates from IBES in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities, and has expressly rejected reliance on other sources.[17] As FERC concluded:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are

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

[17] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 99 FERC ¶ 63,011 at P 53 (2002); *Golden Spread Elec. Coop. Inc.*, 123 FERC ¶ 61,047 (2008);

> biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[18]

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

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

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

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

[18] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) ((footnote omitted).

expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Gas Group?

A. The sustainable, "br+sv" growth rates for each firm in the Gas Group are summarized on page 2 of Exhibit No. 301, Schedule 3, with the underlying details being presented on Exhibit No. 301, Schedule 4. 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 factor 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. Are there significant shortcomings associated with the "br+sv" growth rate?

A. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[19]

I have included the "sustainable growth" approach for completeness, but I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

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

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

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

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

I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they

[19] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006).

expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[20] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[21]

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

A. As noted earlier, S&P has assigned a corporate credit rating of BBB to Avista. Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 5.1% in

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[20] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[21] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

June 2013.[22] It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock.

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

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table WEA-2 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.72% over the period 2014-2017:

TABLE WEA-2
IMPLIED BBB BOND YIELD

	2014-17
Projected AA Utility Yield	
IHS Global Insight (a)	5.64%
EIA (b)	6.26%
Average	5.95%
Current BBB - AA Yield Spread (c)	0.77%
Implied Triple-B Utility Yield	**6.72%**

(a) IHS Global Insight, U.S. Economic Outlook at 25 (May 2013)
(b) Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Jan. 2013 - Jun. 2013

[22] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb approximately 250 basis points through 2018.[23]

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

A. As highlighted on page 3 of Exhibit No. 301, Schedule 3, low-end DCF estimates ranged from 5.5% to 6.7%. In light of the risk-return tradeoff principle and the test of economic logic applied by FERC, 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, consistent with the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. Is there a basis to exclude DCF estimates at the high end of the range?

A. No. The upper end of the DCF range for the Gas Group was set by a cost of equity estimate of 13.3%. While this cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return.

[23] *Blue Chip Financial Forecasts*, Vol. 32, No. 6 (Jun. 1, 2013).

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

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

TABLE WEA-3
DCF RESULTS – GAS GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.0%	10.3%
IBES	9.3%	10.0%
Zacks	8.5%	8.8%
br + sv	9.2%	9.9%

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

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

As shown on page 3 of Exhibit No. 301, Schedule 5 and summarized in Table WEA-4, below, after eliminating illogical values, application of the constant growth DCF model to the Combination Group resulted in the following cost of equity estimates:

TABLE WEA-4
DCF RESULTS – COMBINATION GROUP

	Cost of Equity	
Growth Rate	Average	Midpoint
Value Line	9.2%	11.1%
IBES	9.2%	10.0%
Zacks	9.0%	9.8%
br + sv	8.1%	8.6%

D. Empirical Capital Asset Pricing Model

Q. Please describe the CAPM.

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

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

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

Like the DCF model, the 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. What other considerations are relevant in evaluating a fair ROE using the CAPM?

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

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[24]

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

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

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

A. Application of the ECAPM to the Gas Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No.

301, Schedule 7. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES, 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 for the 390 individual firms, current estimates imply an average growth rate over the next five years of 10.1%. Combining this average growth rate with a year-ahead dividend yield of 2.5% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 12.6%. Subtracting a 3.2% risk-free rate based on the average yield on 30-year Treasury bonds for 2013 produced a market equity risk premium of 9.4%.

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

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

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

A. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[25]

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[24] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).
[25] *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at p. 85.

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

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[26] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of 6.0% for a company in the first decile (market capitalization less than $254.6 million), to a reduction of 37 basis points for firms in the tenth decile (market capitalization between $17.6 billion and $626.6 billion). Accordingly, my ECAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Gas Group.

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

A. As shown on page 1 of Exhibit No. 301, Schedule 7, a forward-looking application of the ECAPM approach resulted in an average unadjusted ROE estimate of 10.5%.[27] After adjusting for the impact of firm size, the ECAPM approach implied an

[26] *Id.* at Table C-1.
[27] The midpoint of the unadjusted ECAPM range was 10.6%.

average cost of equity of 11.4% for the Gas Group, with a midpoint cost of equity estimate of 11.0%.

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

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. Accordingly, in addition to the use of current bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. As shown on page 2 of Exhibit No. 301, Schedule 7, incorporating a forecasted Treasury bond yield for 2014-2017 implied a cost of equity of approximately 10.8% for the Gas Group, or 11.6% after adjusting for the impact of relative size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 10.9% and 11.2%, respectively.

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

A. An identical application of the ECAPM to the firms in the Combination Group is presented on Exhibit No. 301, Schedule 8. As shown on page 1, the forward-looking ECAPM analysis resulted in an average unadjusted ROE estimate of 10.5% for the Combination group, or 11.3% after adjusting for the impact of firm size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 10.6% and 11.0%, respectively. Incorporating a projected Treasury bond yield for 2014-2017 (Exhibit No. 301, Schedule 8, p.

2) implied a cost of equity of approximately 10.7% for the Combination Group, or 11.6% after adjusting for the impact of relative size.[28]

E. Utility Risk Premium

Q. Briefly describe the risk premium method.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. How did you implement the risk premium method?

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

[28] The midpoint of the unadjusted ECAPM range was 10.9%, or 11.2% after adjusting for relative size.

data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

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

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

Q. How did you implement the risk premium method using surveys of allowed ROEs?

A. Surveys of previously authorized ROEs are frequently referenced as the basis for estimating equity risk premiums. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit No. 301, Schedule 9, the average yield on public utility bonds is subtracted from the average allowed ROE for gas utilities to calculate equity risk premiums for each quarter between 1980 and 2011.[29] As shown on page 3 of Exhibit No. 301, Schedule 9, over this period, these equity risk premiums for electric utilities averaged 3.25%, and the yield on public utility bonds averaged 8.69%.

[29] My analysis encompasses the entire period for which published data is available.

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

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[30] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Finally, it is important to recognize that the historical focus of risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's utility industry.

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

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit No. 301, Schedule 9, the equity risk premium for

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

gas utilities increased approximately 46 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. 301, Schedule 9, with an average yield on single-A public utility bonds for 2013 of 4.50%, this implied a current equity risk premium of 5.17% for gas utilities. Adding this equity risk premium to the average yield on triple-B utility bonds for 2013 of 5.01% implies a current cost of equity of approximately 10.2%.

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

A. As shown on page 2 of Exhibit No. 301, Schedule 9, incorporating a forecasted yield for 2014-2017 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.39% for gas utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2014-2017 of 6.72% resulted in an implied cost of equity of approximately 11.1%.

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

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

A. Yes. First, an adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[31] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[32]

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

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

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[31] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.
[32] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

> 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.[33]

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%.[34]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to an average dividend yield of 4.0% implies a flotation cost adjustment on the order of 14 to 40 basis points.

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

A. Yes. I included a minimum adjustment for flotation costs of 14 basis points in evaluating a fair ROE range for Avista.

VI. OTHER ROE BENCHMARKS

Q. Did you examine other benchmarks to confirm that the end-results of your ROE analyses are reasonable?

A. Yes. Exhibit No. 302 presents alternative tests to confirm my conclusion that a 10.1% ROE falls well within a reasonable range and does not exceed a fair return given the facts and circumstances of Avista. These tests include applications of the traditional CAPM analysis using current and projected interest rates, a review of expected earned returns and allowed rates of return for the utility proxy groups. Finally, Exhibit No. 302 also presents a

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[33] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

[34] *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%.

DCF analysis for a low risk group of non-utility firms, with which Avista must compete for investors' money.

Q. What did these alternative analyses indicate regarding Avista's requested ROE in this case?

A. As shown in Exhibit No. 302, Table WEA-7, the alternative ROE benchmarks ranged from 9.6% to 12.8%, with the majority falling in the range of 10.0% to 11.7%. The results of these alternative benchmarks confirm my conclusion that an ROE of 10.1% for Avista's gas operations is reasonable.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

WILLIAM E. AVERA
Exhibit No. 301

Return on Equity

RECOMMENDED ROE RANGE

	Range		
DCF	9.20%	--	10.20%
ECAPM	10.30%	--	11.30%
Utility Risk Premium	10.20%	--	11.10%
Recommended ROE Range	**9.90%**	--	**10.90%**
Flotation Cost Adjustment			
Dividend Yield	4.00%		4.00%
Flotation Cost Percentage	3.60%		3.60%
Adjustment	0.14%		0.14%
Adjusted Cost of Equity Range	**10.04%**	--	**11.04%**

SUMMARY OF RESULTS

	Gas Group		Combination Group	
DCF	**Average**	**Midpoint**	**Average**	**Midpoint**
Value Line	10.0%	10.3%	9.2%	11.1%
IBES	9.3%	10.0%	9.2%	10.0%
Zacks	8.5%	8.8%	9.0%	9.8%
br + sv	9.2%	9.9%	8.1%	8.6%
Empirical CAPM - 2013 Yield				
Unadjusted	10.3%	10.5%	10.5%	10.6%
Size Adjusted	11.8%	12.0%	11.3%	11.0%
Empirical CAPM - Projected Yield				
Unadjusted	10.7%	10.2%	10.7%	10.9%
Size Adjusted	12.1%	11.9%	11.6%	11.2%
Utility Risk Premium				
2013 Bond Yields	10.2%		--	
Projected Bond Yields	11.1%		--	

CHECKS OF REASONABLENESS

	Gas Group		Combination Group	
	Average	Midpoint	Average	Midpoint
CAPM - 2013 Yield				
Unadjusted	9.6%	9.8%	9.8%	10.0%
Size Adjusted	11.1%	10.6%	10.6%	10.3%
CAPM - Projected Yield				
Unadjusted	10.0%	10.2%	10.1%	10.3%
Size Adjusted	11.5%	11.7%	11.0%	10.6%
Expected Earnings	11.6%	12.5%	10.5%	12.3%
Allowed ROE	10.3%	10.6%	10.3%	10.1%
Non-Utility DCF				
Value Line	11.6%	11.7%		
IBES	11.7%	12.8%		
Zacks	11.8%	12.8%		

GAS GROUP

		At Fiscal Year-End 2012 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	AGL Resources	50.8%	0.0%	49.2%	51.5%	0.0%	48.5%
2	Atmos Energy Corp.	45.3%	0.0%	54.7%	49.0%	0.0%	51.0%
3	Laclede Group	37.7%	0.0%	62.3%	48.0%	0.0%	52.0%
4	New Jersey Resources	39.6%	0.0%	60.4%	34.5%	0.0%	65.5%
5	NiSource, Inc.	56.9%	0.0%	43.1%	58.0%	0.0%	42.0%
6	Northwest Natural Gas	48.5%	0.0%	51.5%	48.0%	0.0%	52.0%
7	Piedmont Natural Gas	48.7%	0.0%	51.3%	48.5%	0.0%	51.5%
8	South Jersey Industries	46.0%	0.0%	54.0%	42.0%	0.0%	58.0%
9	Southwest Gas Corp.	50.2%	0.0%	49.8%	48.5%	0.0%	51.5%
10	WGL Holdings, Inc.	31.2%	1.5%	67.3%	28.0%	1.5%	70.5%
	Average	**45.5%**	**0.1%**	**54.4%**	**45.6%**	**0.2%**	**54.3%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Jun. 7, 2013).

CAPITAL STRUCTURE

COMBINATION GROUP

		At Fiscal Year-End 2012 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	Alliant Energy	48.4%	3.2%	48.4%	46.0%	2.5%	51.5%
2	Ameren Corp.	50.8%	0.0%	49.2%	44.0%	1.0%	55.0%
3	Avista Corp.	50.1%	0.0%	49.9%	48.5%	0.0%	51.5%
4	Black Hills Corp.	45.8%	0.0%	54.2%	51.5%	0.0%	48.5%
5	CenterPoint Energy	61.0%	0.0%	39.0%	56.5%	0.0%	43.5%
6	CMS Energy Corp.	69.1%	0.0%	30.9%	62.0%	0.0%	38.0%
7	Consolidated Edison	47.6%	0.0%	52.4%	47.0%	0.0%	53.0%
8	Dominion Resources	64.2%	0.0%	35.8%	58.0%	0.5%	41.5%
9	DTE Energy Co.	50.4%	0.0%	49.6%	50.0%	0.0%	50.0%
10	Duke Energy Corp.	48.5%	0.1%	51.4%	52.0%	0.0%	48.0%
11	Empire District Elec	49.1%	0.0%	50.9%	51.5%	0.0%	48.5%
12	Integrys Energy Group	42.6%	0.0%	57.4%	46.5%	0.5%	53.0%
13	MGE Energy	38.4%	0.0%	61.6%	36.0%	0.0%	64.0%
14	Northeast Utilities	45.9%	0.9%	53.2%	46.5%	0.5%	53.0%
15	NorthWestern Corp.	53.0%	0.0%	47.0%	45.5%	0.0%	54.5%
16	OGE Energy Corp.	48.1%	0.0%	51.9%	43.5%	0.0%	56.5%
17	Pepco Holdings	49.2%	1.0%	49.8%	50.0%	0.0%	50.0%
18	PG&E Corp.	44.7%	0.0%	55.3%	50.0%	1.0%	49.0%
19	Pub Sv Enterprise Grp	48.7%	0.0%	51.3%	44.0%	0.0%	56.0%
20	SCANA Corp.	55.2%	0.0%	44.8%	53.5%	0.0%	46.5%
21	Sempra Energy	53.6%	0.1%	46.3%	54.0%	0.5%	45.5%
22	UIL Holdings	53.1%	10.9%	36.0%	54.5%	0.0%	45.5%
23	Vectren Corp.	52.1%	0.0%	47.9%	48.5%	0.0%	51.5%
	Average	**50.9%**	**0.7%**	**48.4%**	**49.5%**	**0.3%**	**50.2%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).

DCF MODEL - GAS GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	AGL Resources	$ 43.28	$ 1.88	4.3%
2	Atmos Energy Corp.	$ 43.52	$ 1.42	3.3%
3	Laclede Group	$ 46.37	$ 1.70	3.7%
4	New Jersey Resources	$ 45.95	$ 1.60	3.5%
5	NiSource, Inc.	$ 29.39	$ 0.98	3.3%
6	Northwest Natural Gas	$ 44.13	$ 1.82	4.1%
7	Piedmont Natural Gas	$ 34.14	$ 1.24	3.6%
8	South Jersey Industries	$ 59.55	$ 1.85	3.1%
9	Southwest Gas Corp.	$ 49.46	$ 1.35	2.7%
10	WGL Holdings, Inc.	$ 44.45	$ 1.68	3.8%
	Average			**3.5%**

(a) Average of closing prices for 30 trading days ended Jun. 7, 2013.
(b) The Value Line Investment Survey, Summary & Index (Jun. 7, 2013).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	AGL Resources	9.0%	NA	3.5%	5.7%
2	Atmos Energy Corp.	5.5%	6.0%	6.0%	4.9%
3	Laclede Group	5.5%	8.9%	3.0%	7.3%
4	New Jersey Resources	2.0%	4.0%	4.0%	4.8%
5	NiSource, Inc.	8.5%	7.9%	6.7%	4.7%
6	Northwest Natural Gas	5.0%	3.8%	3.8%	5.0%
7	Piedmont Natural Gas	3.0%	5.0%	4.3%	4.0%
8	South Jersey Industries	8.0%	6.0%	6.0%	9.2%
9	Southwest Gas Corp.	7.0%	5.5%	5.3%	7.1%
10	WGL Holdings, Inc.	3.5%	5.3%	5.3%	3.9%

(a) The Value Line Investment Survey (Jun. 7, 2013).
(b) www.finance.yahoo.com (retrieved Jun. 27, 2013).
(c) www.zacks.com (retrieved Jun. 27, 2013).
(d) See Avista/301, Schedule WEA-4.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	AGL Resources	13.3%	NA	7.8%	10.1%
2	Atmos Energy Corp.	8.8%	9.3%	9.3%	8.2%
3	Laclede Group	9.2%	12.6%	6.7%	11.0%
4	New Jersey Resources	5.5%	7.5%	7.5%	8.3%
5	NiSource, Inc.	11.8%	11.2%	10.0%	8.1%
6	Northwest Natural Gas	9.1%	7.9%	7.9%	9.1%
7	Piedmont Natural Gas	6.6%	8.6%	7.9%	7.6%
8	South Jersey Industries	11.1%	9.1%	9.1%	12.3%
9	Southwest Gas Corp.	9.7%	8.2%	8.0%	9.9%
10	WGL Holdings, Inc.	7.3%	9.0%	9.1%	7.7%
	Average (b)	**10.0%**	**9.3%**	**8.5%**	**9.2%**
	Midpoint (c)	**10.3%**	**10.0%**	**8.8%**	**9.9%**

(a) Sum of dividend yield (Avista/301, Schedule WEA-3, p. 1) and respective growth rate (Avista/301, Schedule WEA-3, p. 2).

(b) Excludes highlighted figures.

(c) Average of low and high values.

DCF MODEL - GAS GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		-------------- 2017	-------------				Adjustment			--------- "sv" Factor	--------		
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	AGL Resources	$4.10	$2.04	$36.05	50.2%	11.4%	1.0215	11.6%	5.8%	(0.0026)	0.4232	-0.11%	**5.7%**
2	Atmos Energy Corp.	$3.00	$1.50	$34.65	50.0%	8.7%	1.0413	9.0%	4.5%	0.0309	0.1338	0.41%	**4.9%**
3	Laclede Group	$3.75	$1.82	$28.65	51.5%	13.1%	1.0135	13.3%	6.8%	0.0125	0.3870	0.48%	**7.3%**
4	New Jersey Resources	$2.95	$1.72	$23.50	41.7%	12.6%	1.0147	12.7%	5.3%	(0.0127)	0.4125	-0.53%	**4.8%**
5	NiSource, Inc.	$1.90	$1.10	$18.80	42.1%	10.1%	1.0114	10.2%	4.3%	0.0137	0.3200	0.44%	**4.7%**
6	Northwest Natural Gas	$3.30	$2.00	$31.70	39.4%	10.4%	1.0192	10.6%	4.2%	0.0157	0.4982	0.78%	**5.0%**
7	Piedmont Natural Gas	$1.90	$1.39	$17.60	26.8%	10.8%	1.0261	11.1%	3.0%	0.0203	0.5000	1.02%	**4.0%**
8	South Jersey Industries	$4.60	$2.45	$36.00	46.7%	12.8%	1.0404	13.3%	6.2%	0.0555	0.5300	2.94%	**9.2%**
9	Southwest Gas Corp.	$3.75	$1.60	$36.00	57.3%	10.4%	1.0319	10.7%	6.2%	0.0258	0.3739	0.96%	**7.1%**
10	WGL Holdings, Inc.	$2.95	$1.83	$29.80	38.0%	9.9%	1.0186	10.1%	3.8%	0.0027	0.2763	0.07%	**3.9%**

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2012			2017			Chg	2017 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2012	2017	Growth
1	AGL Resources	50.5%	$6,716	$3,392	48.5%	$8,670	$4,205	4.4%	$70.00	$55.00	$62.50	1.734	117.88	117.00	-0.15%
2	Atmos Energy Corp.	54.7%	$4,316	$2,361	51.0%	$7,000	$3,570	8.6%	$50.00	$35.00	$42.50	1.154	90.24	103.00	2.68%
3	Laclede Group	64.0%	$941	$602	52.0%	$1,325	$689	2.7%	$65.00	$50.00	$57.50	1.631	22.62	23.50	0.77%
4	New Jersey Resources	60.8%	$1,339	$814	65.5%	$1,440	$943	3.0%	$45.00	$35.00	$40.00	1.702	41.53	40.00	-0.75%
5	NiSource, Inc.	44.9%	$12,373	$5,555	42.0%	$14,820	$6,224	2.3%	$35.00	$25.00	$30.00	1.471	310.28	325.00	0.93%
6	Northwest Natural Gas	51.5%	$1,425	$734	52.0%	$1,710	$889	3.9%	$60.00	$50.00	$55.00	1.993	26.92	28.00	0.79%
7	Piedmont Natural Gas	51.3%	$2,002	$1,027	51.5%	$2,590	$1,334	5.4%	$40.00	$30.00	$35.00	2.000	72.25	76.00	1.02%
8	South Jersey Industries	55.0%	$1,338	$736	58.0%	$1,900	$1,102	8.4%	$75.00	$55.00	$65.00	2.128	31.65	36.00	2.61%
9	Southwest Gas Corp.	50.8%	$2,579	$1,310	51.5%	$3,500	$1,803	6.6%	$70.00	$45.00	$57.50	1.597	46.15	50.00	1.62%
10	WGL Holdings, Inc.	67.5%	$1,887	$1,274	70.5%	$2,175	$1,533	3.8%	$50.00	$40.00	$45.00	1.382	51.50	52.00	0.19%

(a) The Value Line Investment Survey (Jun. 7, 2013).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2017 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2017 BVPS.

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Alliant Energy	$ 50.19	$ 1.92	3.8%
2	Ameren Corp.	$ 34.59	$ 1.60	4.6%
3	Avista Corp.	$ 27.42	$ 1.25	4.6%
4	Black Hills Corp.	$ 48.17	$ 1.54	3.2%
5	CenterPoint Energy	$ 23.53	$ 0.84	3.6%
6	CMS Energy Corp.	$ 27.53	$ 1.05	3.8%
7	Consolidated Edison	$ 58.44	$ 2.48	4.2%
8	Dominion Resources	$ 57.40	$ 2.28	4.0%
9	DTE Energy Co.	$ 68.04	$ 2.62	3.9%
10	Duke Energy Corp.	$ 68.61	$ 3.12	4.5%
11	Empire District Elec	$ 22.15	$ 1.00	4.5%
12	Integrys Energy Group	$ 58.46	$ 2.72	4.7%
13	MGE Energy	$ 54.74	$ 1.62	3.0%
14	Northeast Utilities	$ 42.50	$ 1.49	3.5%
15	NorthWestern Corp.	$ 41.07	$ 1.54	3.7%
16	OGE Energy Corp.	$ 68.74	$ 0.88	1.3%
17	Pepco Holdings	$ 20.96	$ 1.08	5.2%
18	PG&E Corp.	$ 45.59	$ 1.82	4.0%
19	Pub Sv Enterprise Grp	$ 33.38	$ 1.45	4.3%
20	SCANA Corp.	$ 50.79	$ 2.04	4.0%
21	Sempra Energy	$ 81.07	$ 2.58	3.2%
22	UIL Holdings	$ 39.63	$ 1.73	4.4%
23	Vectren Corp.	$ 34.62	$ 1.44	4.2%
24	Wisconsin Energy	$ 41.66	$ 1.53	3.7%
25	Xcel Energy, Inc.	$ 29.32	$ 1.13	3.9%
	Average			**3.9%**

(a) Average of closing prices for 30 trading days ended June 21, 2013.
(b) The Value Line Investment Survey, Summary & Index (Aug. 2, 2013).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	Alliant Energy	5.0%	5.9%	5.7%	5.1%
2	Ameren Corp.	-0.5%	-1.2%	2.5%	2.8%
3	Avista Corp.	4.0%	4.5%	4.3%	2.9%
4	Black Hills Corp.	11.5%	5.0%	5.0%	4.1%
5	CenterPoint Energy	4.5%	4.8%	5.3%	5.1%
6	CMS Energy Corp.	5.5%	5.9%	6.1%	5.0%
7	Consolidated Edison	2.5%	1.7%	3.3%	3.5%
8	Dominion Resources	6.0%	7.0%	5.9%	6.1%
9	DTE Energy Co.	4.0%	4.7%	4.7%	3.7%
10	Duke Energy Corp.	4.0%	3.9%	3.1%	2.6%
11	Empire District Elec	5.0%	3.0%	3.0%	2.9%
12	Integrys Energy Group	3.5%	5.5%	5.0%	2.9%
13	MGE Energy	4.5%	4.0%	4.0%	5.7%
14	Northeast Utilities	8.0%	7.4%	7.9%	4.4%
15	NorthWestern Corp.	4.5%	4.0%	5.0%	4.1%
16	OGE Energy Corp.	5.0%	4.6%	5.6%	-4.0%
17	Pepco Holdings	6.0%	4.2%	5.1%	2.9%
18	PG&E Corp.	2.5%	2.3%	1.8%	3.2%
19	Pub Sv Enterprise Grp	-2.5%	-2.7%	-0.1%	3.9%
20	SCANA Corp.	4.5%	4.8%	4.7%	5.3%
21	Sempra Energy	4.5%	5.0%	5.0%	5.2%
22	UIL Holdings	4.0%	8.1%	8.0%	3.0%
23	Vectren Corp.	6.5%	5.0%	5.0%	5.3%
24	Wisconsin Energy	5.5%	4.9%	5.2%	4.7%
25	Xcel Energy, Inc.	4.5%	5.1%	5.0%	4.4%

(a) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).
(b) www.finance.yahoo.com (retrieved Jul. 29, 2013).
(c) www.zacks.com (retrieved Jul. 29, 2013).
(d) See Avista/301, Schedule WEA-6.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Alliant Energy	8.8%	9.7%	9.5%	8.9%
2	Ameren Corp.	4.1%	3.4%	7.2%	7.5%
3	Avista Corp.	8.6%	9.1%	8.9%	7.5%
4	Black Hills Corp.	14.7%	8.2%	8.2%	7.3%
5	CenterPoint Energy	8.1%	8.4%	8.9%	8.7%
6	CMS Energy Corp.	9.3%	9.7%	9.9%	8.9%
7	Consolidated Edison	6.7%	6.0%	7.5%	7.7%
8	Dominion Resources	10.0%	11.0%	9.9%	10.1%
9	DTE Energy Co.	7.9%	8.5%	8.5%	7.6%
10	Duke Energy Corp.	8.5%	8.4%	7.6%	7.1%
11	Empire District Elec	9.5%	7.5%	7.5%	7.4%
12	Integrys Energy Group	8.2%	10.2%	9.7%	7.6%
13	MGE Energy	7.5%	7.0%	7.0%	8.7%
14	Northeast Utilities	11.5%	10.9%	11.4%	7.9%
15	NorthWestern Corp.	8.2%	7.7%	8.7%	7.9%
16	OGE Energy Corp.	6.3%	5.8%	6.9%	-2.7%
17	Pepco Holdings	11.2%	9.4%	10.3%	8.0%
18	PG&E Corp.	6.5%	6.3%	5.8%	7.2%
19	Pub Sv Enterprise Grp	1.8%	1.7%	4.2%	8.2%
20	SCANA Corp.	8.5%	8.8%	8.7%	9.3%
21	Sempra Energy	7.7%	8.1%	8.1%	8.4%
22	UIL Holdings	8.4%	12.4%	12.4%	7.3%
23	Vectren Corp.	10.7%	9.2%	9.2%	9.5%
24	Wisconsin Energy	9.2%	8.6%	8.9%	8.4%
25	Xcel Energy, Inc.	8.4%	8.9%	8.8%	8.2%
	Average (b)	**9.2%**	**9.2%**	**9.0%**	**8.1%**
	Midpoint (c)	**11.1%**	**10.0%**	**9.8%**	**8.6%**

(a) Sum of dividend yield (Avista/301, Schedule WEA-5, p. 1) and respective growth rate (Avista/301, Schedule WEA-5, p. 2).

(b) Excludes highlighted figures.

(c) Average of low and high values.

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2017					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$3.80	$2.20	$34.50	42.1%	11.0%	1.0248	11.3%	4.8%	0.0122	0.2737	0.33%	**5.1%**
2	Ameren Corp.	$2.50	$1.70	$29.50	32.0%	8.5%	1.0131	8.6%	2.7%	0.0110	0.0923	0.10%	**2.8%**
3	Avista Corp.	$2.00	$1.40	$24.00	30.0%	8.3%	1.0204	8.5%	2.6%	0.0170	0.2000	0.34%	**2.9%**
4	Black Hills Corp.	$3.00	$1.70	$33.25	43.3%	9.0%	1.0206	9.2%	4.0%	0.0075	0.1133	0.09%	**4.1%**
5	CenterPoint Energy	$1.60	$1.00	$12.50	37.5%	12.8%	1.0226	13.1%	4.9%	0.0047	0.4444	0.21%	**5.1%**
6	CMS Energy Corp.	$2.00	$1.30	$16.00	35.0%	12.5%	1.0323	12.9%	4.5%	0.0127	0.4182	0.53%	**5.0%**
7	Consolidated Edison	$4.25	$2.62	$47.75	38.4%	8.9%	1.0161	9.0%	3.5%	0.0001	0.1696	0.00%	**3.5%**
8	Dominion Resources	$4.00	$2.75	$25.50	31.3%	15.7%	1.0365	16.3%	5.1%	0.0185	0.5565	1.03%	**6.1%**
9	DTE Energy Co.	$4.75	$3.15	$53.00	33.7%	9.0%	1.0311	9.2%	3.1%	0.0260	0.2429	0.63%	**3.7%**
10	Duke Energy Corp.	$5.00	$3.35	$64.25	33.0%	7.8%	1.0106	7.9%	2.6%	0.0017	0.0115	0.00%	**2.6%**
11	Empire District Elec	$1.70	$1.20	$19.25	29.4%	8.8%	1.0210	9.0%	2.7%	0.0196	0.1250	0.25%	**2.9%**
12	Integrys Energy Group	$4.00	$2.80	$46.50	30.0%	8.6%	1.0276	8.8%	2.7%	0.0226	0.1143	0.26%	**2.9%**
13	MGE Energy	$3.60	$1.86	$31.90	48.3%	11.3%	1.0256	11.6%	5.6%	0.0029	0.4200	0.12%	**5.7%**
14	Northeast Utilities	$3.25	$1.80	$34.50	44.6%	9.4%	1.0182	9.6%	4.3%	0.0041	0.2333	0.10%	**4.4%**
15	NorthWestern Corp.	$3.00	$1.80	$31.25	40.0%	9.6%	1.0261	9.9%	3.9%	0.0113	0.1667	0.19%	**4.1%**
16	OGE Energy Corp.	$2.25	$1.05	$19.00	53.3%	11.8%	1.0338	12.2%	6.5%	(0.2298)	0.4571	-10.50%	**-4.0%**
17	Pepco Holdings	$1.70	$1.16	$21.50	31.8%	7.9%	1.0202	8.1%	2.6%	0.0237	0.1224	0.29%	**2.9%**
18	PG&E Corp.	$3.00	$2.10	$35.25	30.0%	8.5%	1.0242	8.7%	2.6%	0.0252	0.2167	0.55%	**3.2%**
19	Pub Sv Enterprise Grp	$2.50	$1.52	$25.75	39.2%	9.7%	1.0187	9.9%	3.9%	0.0001	0.2077	0.00%	**3.9%**
20	SCANA Corp.	$4.00	$2.25	$41.50	43.8%	9.6%	1.0444	10.1%	4.4%	0.0430	0.2095	0.90%	**5.3%**
21	Sempra Energy	$5.50	$3.00	$52.00	45.5%	10.6%	1.0233	10.8%	4.9%	0.0093	0.3290	0.30%	**5.2%**
22	UIL Holdings	$2.55	$1.73	$28.45	32.2%	9.0%	1.0265	9.2%	3.0%	0.0007	0.2888	0.02%	**3.0%**
23	Vectren Corp.	$2.60	$1.60	$23.00	38.5%	11.3%	1.0274	11.6%	4.5%	0.0199	0.4250	0.84%	**5.3%**
24	Wisconsin Energy	$3.00	$2.00	$21.25	33.3%	14.1%	1.0162	14.3%	4.8%	(0.0010)	0.5278	-0.05%	**4.7%**
25	Xcel Energy, Inc.	$2.25	$1.35	$23.00	40.0%	9.8%	1.0274	10.1%	4.0%	0.0141	0.2333	0.33%	**4.4%**

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2012			2017			Chg	2017 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2012	2017	Growth
1	Alliant Energy	48.4%	$6,477	$3,135	51.5%	$7,800	$4,017	5.1%	$55.00	$40.00	$47.50	1.377	110.99	116.00	0.89%
2	Ameren Corp.	49.4%	$13,384	$6,612	55.0%	$13,700	$7,535	2.6%	$40.00	$25.00	$32.50	1.102	242.65	255.00	1.00%
3	Avista Corp.	49.2%	$2,561	$1,260	51.5%	$3,000	$1,545	4.2%	$35.00	$25.00	$30.00	1.250	59.81	64.00	1.36%
4	Black Hills Corp.	56.8%	$2,171	$1,233	48.5%	$3,125	$1,516	4.2%	$45.00	$30.00	$37.50	1.128	44.21	45.70	0.67%
5	CenterPoint Energy	34.0%	$12,658	$4,304	43.5%	$12,400	$5,394	4.6%	$25.00	$20.00	$22.50	1.800	427.44	433.00	0.26%
6	CMS Energy Corp.	31.6%	$10,101	$3,192	38.0%	$11,600	$4,408	6.7%	$35.00	$20.00	$27.50	1.719	264.10	274.00	0.74%
7	Consolidated Edison	54.1%	$21,933	$11,866	53.0%	$26,300	$13,939	3.3%	$65.00	$50.00	$57.50	1.204	292.87	293.00	0.01%
8	Dominion Resources	38.2%	$27,676	$10,572	41.5%	$36,700	$15,231	7.6%	$65.00	$50.00	$57.50	2.255	576.00	600.00	0.82%
9	DTE Energy Co.	51.2%	$14,387	$7,366	50.0%	$20,100	$10,050	6.4%	$80.00	$60.00	$70.00	1.321	172.35	190.00	1.97%
10	Duke Energy Corp.	52.9%	$77,307	$40,895	48.0%	$94,700	$45,456	2.1%	$75.00	$55.00	$65.00	1.012	704.00	710.00	0.17%
11	Empire District Elec	50.9%	$1,409	$717	48.5%	$1,825	$885	4.3%	$25.00	$19.00	$22.00	1.143	42.48	46.25	1.72%
12	Integrys Energy Group	60.4%	$5,009	$3,025	53.0%	$7,525	$3,988	5.7%	$60.00	$45.00	$52.50	1.129	77.90	86.00	2.00%
13	MGE Energy	61.8%	$938	$580	64.0%	$1,170	$749	5.3%	$60.00	$50.00	$55.00	1.724	23.30	23.50	0.17%
14	Northeast Utilities	55.4%	$16,675	$9,238	53.0%	$20,900	$11,077	3.7%	$50.00	$40.00	$45.00	1.304	314.05	319.00	0.31%
15	NorthWestern Corp.	46.2%	$2,021	$934	54.5%	$2,225	$1,213	5.4%	$45.00	$30.00	$37.50	1.200	37.22	39.00	0.94%
16	OGE Energy Corp.	49.3%	$5,616	$2,769	56.5%	$6,875	$3,884	7.0%	$40.00	$30.00	$35.00	1.842	197.60	101.50	-12.47%
17	Pepco Holdings	52.7%	$8,432	$4,444	50.0%	$10,880	$5,440	4.1%	$30.00	$19.00	$24.50	1.140	230.02	255.00	2.08%
18	PG&E Corp.	50.4%	$25,956	$13,082	49.0%	$34,000	$16,660	5.0%	$55.00	$35.00	$45.00	1.277	430.72	475.00	1.98%
19	Pub Sv Enterprise Grp	61.7%	$17,467	$10,777	56.0%	$23,200	$12,992	3.8%	$35.00	$30.00	$32.50	1.262	505.89	506.00	0.00%
20	SCANA Corp.	45.6%	$9,103	$4,151	46.5%	$13,925	$6,475	9.3%	$60.00	$45.00	$52.50	1.265	132.00	156.00	3.40%
21	Sempra Energy	46.7%	$22,002	$10,275	45.5%	$28,500	$12,968	4.8%	$90.00	$65.00	$77.50	1.490	242.37	250.00	0.62%
22	UIL Holdings	41.1%	$2,717	$1,117	45.5%	$3,200	$1,456	5.5%	$45.00	$35.00	$40.00	1.406	50.87	51.00	0.05%
23	Vectren Corp.	49.6%	$3,080	$1,527	51.5%	$3,900	$2,009	5.6%	$45.00	$35.00	$40.00	1.739	82.20	87.00	1.14%
24	Wisconsin Energy	48.0%	$8,619	$4,137	49.5%	$9,825	$4,863	3.3%	$50.00	$40.00	$45.00	2.118	229.04	228.50	-0.05%
25	Xcel Energy, Inc.	46.7%	$19,018	$8,881	49.5%	$23,600	$11,682	5.6%	$35.00	$25.00	$30.00	1.304	487.96	515.00	1.08%

(a) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2017 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2017 BVPS.

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP [1]	Beta	Weight	RP [2]	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.75	75%	5.3%	7.6%	10.8%	4,944.63	0.92%	11.8%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.70	75%	4.9%	7.3%	10.5%	3,520.12	1.14%	11.6%
3	Laclede Group	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.60	75%	4.2%	6.6%	9.8%	1,008.07	1.73%	11.5%
4	New Jersey Resources	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	1,751.25	1.72%	11.9%
5	NiSource, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.80	75%	5.6%	8.0%	11.2%	8,612.30	0.76%	12.0%
6	Northwest Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.60	75%	4.2%	6.6%	9.8%	1,131.28	1.73%	11.5%
7	Piedmont Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	2,487.40	1.70%	11.8%
8	South Jersey Industries	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	1,765.84	1.72%	11.9%
9	Southwest Gas Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.75	75%	5.3%	7.6%	10.8%	2,119.83	1.70%	12.5%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	2,160.11	1.70%	11.8%
	Average												**10.3%**			**11.8%**
	Midpoint (n)												**10.5%**			**12.0%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jun. 21, 2013).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 15, 2013).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2013 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); & Blue Chip Financial Forecasts, Vol. 32, No. 6 (Jun. 1, 2013).
(e) (c) - (d).
(f) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(g) (e) x weighting factor.
(h) The Value Line Investment Survey (Jun. 7, 2013).
(i) (e) x (h) x weighting factor.
(j) (d) + (g) + (i).
(k) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
(l) *Morningstar* , "2013 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2013).
(m) (g) + (h).
(n) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				**Market**										**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**				**Empirical**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*[1]**	**Beta**	**Weight**	***RP*[2]**	**Total RP**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	AGL Resources	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.1%	4,944.63	0.92%	12.0%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.8%	3,520.12	1.14%	11.9%
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5	NiSource, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.80	75%	4.9%	6.9%	11.4%	8,612.30	0.76%	12.1%
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9	Southwest Gas Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.1%	2,119.83	1.70%	12.8%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.65	75%	3.9%	6.0%	10.5%	2,160.11	1.70%	12.2%
	Average												**10.7%**			**12.1%**
	Midpoint (n)												**10.2%**			**11.9%**

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(c) (a) + (b).
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(e) (c) - (d).
(f) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(g) (e) x weighting factor.
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(i) (e) x (h) x weighting factor.
(j) (d) + (g) + (i).
(k) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
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(m) (g) + (h).
(n) Average of low and high values.

EMPIRICAL CAPM - 2013 BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	5,937.7	0.92%	11.4%
2	Ameren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	8,665.7	0.76%	11.9%
3	Avista Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	1,724.3	1.72%	12.2%
4	Black Hills Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	2,333.5	1.70%	12.9%
5	CenterPoint Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	10,588.8	0.76%	11.9%
6	CMS Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	7,495.4	0.92%	11.7%
7	Consolidated Edison	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	17,408.1	0.76%	10.5%
8	Dominion Resources	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	10.1%	34,290.9	-0.37%	9.7%
9	DTE Energy Co.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	12,180.0	0.76%	11.6%
10	Duke Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	49,843.6	-0.37%	9.4%
11	Empire District Elec	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	10.1%	1,020.5	1.73%	11.8%
12	Integrys Energy Group	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.90	75%	6.4%	8.8%	11.9%	4,908.0	0.92%	12.8%
13	MGE Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	1,382.2	1.72%	11.5%
14	Northeast Utilities	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	13,958.6	0.76%	11.2%
15	NorthWestern Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	1,587.4	1.72%	12.2%
16	OGE Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	7,497.2	0.92%	11.7%
17	Pepco Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	5,048.1	0.92%	11.7%
18	PG&E Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.55	75%	3.9%	6.3%	9.4%	19,794.7	-0.37%	9.0%
19	Pub Sv Enterprise Grp	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	17,250.0	0.76%	11.6%
20	SCANA Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	10.1%	7,276.0	0.92%	11.0%
21	Sempra Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	21,193.3	-0.37%	10.8%
22	UIL Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	2,068.6	1.70%	12.2%
23	Vectren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	2,992.4	1.14%	11.6%
24	Wisconsin Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	9,931.2	0.76%	10.5%
25	Xcel Energy, Inc.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	14,743.7	0.76%	10.5%
	Average												**10.5%**			**11.3%**
	Midpoint (h)												**10.6%**			**11.0%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Apr. 15, 2012).
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(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).
(f) ($ millions) www.valueline.com (retrieved July 29, 2013).
(g) *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).
(h) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
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	Average												**10.7%**			**11.6%**
	Midpoint (h)												**10.9%**			**11.2%**

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(h) Average of low and high values.

GAS UTILITY RISK PREMIUM

2013 BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	2013 Single-A Utility Bond Yield	4.50%
	Change in Bond Yield	-4.19%
(c)	Risk Premium/Interest Rate Relationship	-0.4592
	Adjustment to Average Risk Premium	1.92%
(a)	Average Risk Premium over Study Period	3.25%
	Adjusted Risk Premium	**5.17%**

Implied Cost of Equity

(b)	2013 BBB Utility Bond Yield	5.01%
	Adjusted Equity Risk Premium	5.17%
	Risk Premium Cost of Equity	**10.18%**

(a) Avista/301, Schedule WEA-9, Avera/Page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(c) Avista/301, Schedule WEA-9, Avera/Page 4.

PROJECTED BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.69%
(b)	Projected Single-A Utility Bond Yield 2014-17	6.21%
	Change in Bond Yield	-2.48%
(c)	Risk Premium/Interest Rate Relationship	-0.4592
	Adjustment to Average Risk Premium	1.14%
(a)	Average Risk Premium over Study Period	3.25%
	Adjusted Risk Premium	**4.39%**
Implied Cost of Equity		
(b)	Projected BBB Utility Bond Yield 2014-17	6.72%
	Adjusted Equity Risk Premium	4.39%
	Risk Premium Cost of Equity	**11.11%**

(a) Avista/301, Schedule WEA-9, Avera/Page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(c) Avista/301, Schedule WEA-9, Avera/Page 4.

AUTHORIZED RETURNS

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

Year	Qtr.	(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1997	1	11.31%	7.76%	3.55%
	2	11.70%	7.88%	3.82%
	3	12.00%	7.49%	4.51%
	4 (c)	11.01%	7.25%	3.76%
1998	2	11.37%	7.12%	4.25%
	3	11.41%	6.99%	4.42%
	4	11.69%	6.97%	4.72%
1999	1	10.82%	7.11%	3.71%
	2 (c)	10.82%	7.48%	3.34%
	4	10.33%	8.05%	2.28%
2000	1	10.71%	8.29%	2.42%
	2	11.08%	8.45%	2.63%
	3	11.33%	8.25%	3.08%
	4	12.50%	8.03%	4.47%
2001	1	11.16%	7.74%	3.42%
	2 (c)	10.75%	7.93%	2.82%
	4	10.65%	7.68%	2.97%
2002	1	10.67%	7.65%	3.02%
	2	11.64%	7.50%	4.14%
	3	11.50%	7.19%	4.31%
	4	10.78%	7.15%	3.63%
2003	1	11.38%	6.93%	4.45%
	2	11.36%	6.40%	4.96%
	3	10.61%	6.64%	3.97%
	4	10.84%	6.35%	4.49%
2004	1	11.10%	6.09%	5.01%
	2	10.25%	6.48%	3.77%
	3	10.37%	6.13%	4.24%
	4	10.66%	5.94%	4.72%
2005	1	10.65%	5.74%	4.91%
	2	10.52%	5.52%	5.00%
	3	10.47%	5.51%	4.96%
	4	10.40%	5.82%	4.58%
2006	1	10.63%	5.85%	4.78%
	2	10.50%	6.37%	4.13%
	3	10.45%	6.19%	4.26%
	4	10.14%	5.86%	4.28%
2007	1	10.44%	5.90%	4.54%
	2	10.12%	6.09%	4.03%
	3	10.03%	6.22%	3.81%
	4	10.27%	6.08%	4.19%
2008	1	10.38%	6.15%	4.23%
	2	10.17%	6.32%	3.85%
	3	10.49%	6.42%	4.07%
	4	10.34%	7.23%	3.11%
2009	1	10.24%	6.37%	3.87%
	2	10.11%	6.39%	3.72%
	3	9.88%	5.74%	4.14%
	4	10.27%	5.66%	4.61%
2010	1	10.24%	5.83%	4.41%
	2	9.99%	5.61%	4.38%
	3	9.93%	5.09%	4.84%
	4	10.09%	5.34%	4.75%
2011	1	10.10%	5.60%	4.50%
	2	9.85%	5.38%	4.47%
	3	9.65%	4.81%	4.84%
	4	9.88%	4.37%	5.51%
2012	1	9.63%	4.39%	5.24%
	2	9.83%	4.23%	5.60%
	3	9.75%	3.98%	5.77%
	4	10.07%	3.93%	6.14%
2013	1	9.57%	4.18%	5.39%
	2	9.47%	4.23%	5.24%
Average		**11.94%**	**8.69%**	**3.25%**

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (Jul. 9, 2013, Jan. 24, 2002, Jan. 18, 1995, and Jan. 16, 1990).

(b) Moody's Investors Service.

(c) No decisions reported for following quarter.

GAS UTILITY RISK PREMIUM

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.937283
R Square	0.8784994
Adjusted R Square	0.8775502
Standard Error	0.0053743
Observations	130

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.026731022	0.026731	925.4929	1.94165E-60
Residual	128	0.003697026	2.89E-05		
Total	129	0.030428048			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0724076	0.001393513	51.96047	6.69E-88	0.069650272	0.07516487	0.069650272	0.075164874
X Variable 1	-0.4591583	0.015093011	-30.4219	1.94E-60	-0.48902235	-0.42929419	-0.48902235	-0.42929419

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.5%	10.1%	12.6%	3.2%	9.4%	0.75	10.3%	4,944.6	0.92%	11.2%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	0.70	9.8%	3,520.1	1.14%	10.9%
3	Laclede Group	2.5%	10.1%	12.6%	3.2%	9.4%	0.60	8.8%	1,008.1	1.73%	10.6%
4	New Jersey Resources	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	1,751.3	1.72%	11.0%
5	NiSource, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	0.80	10.7%	8,612.3	0.76%	11.5%
6	Northwest Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	0.60	8.8%	1,131.3	1.73%	10.6%
7	Piedmont Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	2,487.4	1.70%	11.0%
8	South Jersey Industries	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	1,765.8	1.72%	11.0%
9	Southwest Gas Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	0.75	10.3%	2,119.8	1.70%	12.0%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	2,160.1	1.70%	11.0%
	Average							**9.6%**			**11.1%**
	Midpoint (k)							**9.8%**			**10.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jun. 21, 2013).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 15, 2013).
(c) (a) + (b).
(d) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 7, 2013).
(g) (d) + (e) x (f).
(h) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
(i) *Morningstar* , "2013 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2013).
(j) (g) + (h).
(k) Average of low and high values.

CAPM - PROJECTED BOND YIELD

GAS GROUP

	Company	(a) Market Return (R_m) Div Yield	(b) Proj. Growth	(c) Cost of Equity	(d) 2014-17 Risk-Free Rate	(e) Risk Premium	(f) Beta	(g) Unadjusted K_e	(h) Market Cap	(i) Size Adjustment	(j) Size Adjusted K_e
1	AGL Resources	2.5%	10.1%	12.6%	4.5%	8.1%	0.75	10.6%	4,944.6	0.92%	11.5%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	0.70	10.2%	3,520.1	1.14%	11.3%
3	Laclede Group	2.5%	10.1%	12.6%	4.5%	8.1%	0.60	9.4%	1,008.1	1.73%	11.1%
4	New Jersey Resources	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	1,751.3	1.72%	11.5%
5	NiSource, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	0.80	11.0%	8,612.3	0.76%	11.7%
6	Northwest Natural Gas	2.5%	10.1%	12.6%	4.5%	8.1%	0.60	9.4%	1,131.3	1.73%	11.1%
7	Piedmont Natural Gas	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	2,487.4	1.70%	11.5%
8	South Jersey Industries	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	1,765.8	1.72%	11.5%
9	Southwest Gas Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	0.75	10.6%	2,119.8	1.70%	12.3%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	2,160.1	1.70%	11.5%
	Average							**10.0%**			**11.5%**
	Midpoint (k)							**10.2%**			**11.7%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jun. 21, 2013).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 15, 2013).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2014-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); & Blue Chip Financial Forecasts, Vol. 32, No. 6 (Jun. 1, 2013).
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 7, 2013).
(g) (d) + (e) x (f).
(h) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
(i) *Morningstar* , "2013 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2013).
(j) (g) + (h).
(k) Average of low and high values.

CAPM - 2013 BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Alliant Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	5,937.7	0.92%	10.7%
2	Ameren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	8,665.7	0.76%	11.5%
3	Avista Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	1,724.3	1.72%	11.5%
4	Black Hills Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	2,333.5	1.70%	12.4%
5	CenterPoint Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	10,588.8	0.76%	11.5%
6	CMS Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	7,495.4	0.92%	11.1%
7	Consolidated Edison	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	17,408.1	0.76%	9.6%
8	Dominion Resources	2.5%	10.1%	12.6%	3.1%	9.5%	0.65	9.3%	34,290.9	-0.37%	8.9%
9	DTE Energy Co.	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	12,180.0	0.76%	11.0%
10	Duke Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	49,843.6	-0.37%	8.4%
11	Empire District Elec	2.5%	10.1%	12.6%	3.1%	9.5%	0.65	9.3%	1,020.5	1.73%	11.0%
12	Integrys Energy Group	2.5%	10.1%	12.6%	3.1%	9.5%	0.90	11.7%	4,908.0	0.92%	12.6%
13	MGE Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	1,382.2	1.72%	10.5%
14	Northeast Utilities	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	13,958.6	0.76%	10.5%
15	NorthWestern Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	1,587.4	1.72%	11.5%
16	OGE Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	7,497.2	0.92%	11.1%
17	Pepco Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	5,048.1	0.92%	11.1%
18	PG&E Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.55	8.3%	19,794.7	-0.37%	8.0%
19	Pub Sv Enterprise Grp	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	17,250.0	0.76%	11.0%
20	SCANA Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.65	9.3%	7,276.0	0.92%	10.2%
21	Sempra Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	21,193.3	-0.37%	10.3%
22	UIL Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	2,068.6	1.70%	11.5%
23	Vectren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	2,992.4	1.14%	10.9%
24	Wisconsin Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	9,931.2	0.76%	9.6%
25	Xcel Energy, Inc.	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	14,743.7	0.76%	9.6%
	Average							**9.8%**			**10.6%**
	Midpoint (g)							**10.0%**			**10.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 13, 2012).

(b) Weighted average based on growth projections from The Value Line Investment Survey (Dec. 13, 2012), www.yahoo.com (retrieved Jan. 6, 2013), and www.zacks.com (retrieved Jan. 6, 2013).

(c) Average yield on 30-year Treasury bonds for 2013 based on data from the ; ; & Based on monthly average bond yields for the six-month period Jan. 2013 - Jun. 2013 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm..

(d) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).

(e) ($ millions) www.valueline.com (retrieved July 29, 2013).

(f) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(g) Average of low and high values.

CAPM - PROJECTED BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	K_e	**Cap**	**Adjustment**	K_e
1	Alliant Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	5,937.7	0.92%	11.0%
2	Ameren Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	8,665.7	0.76%	11.7%
3	Avista Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	1,724.3	1.72%	11.8%
4	Black Hills Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	2,333.5	1.70%	12.6%
5	CenterPoint Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	10,588.8	0.76%	11.7%
6	CMS Energy Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	7,495.4	0.92%	11.4%
7	Consolidated Edison	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	17,408.1	0.76%	10.0%
8	Dominion Resources	2.5%	10.1%	12.6%	4.2%	8.4%	0.65	9.7%	34,290.9	-0.37%	9.3%
9	DTE Energy Co.	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	12,180.0	0.76%	11.3%
10	Duke Energy Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	49,843.6	-0.37%	8.9%
11	Empire District Elec	2.5%	10.1%	12.6%	4.2%	8.4%	0.65	9.7%	1,020.5	1.73%	11.4%
12	Integrys Energy Group	2.5%	10.1%	12.6%	4.2%	8.4%	0.90	11.8%	4,908.0	0.92%	12.7%
13	MGE Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	1,382.2	1.72%	11.0%
14	Northeast Utilities	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	13,958.6	0.76%	10.8%
15	NorthWestern Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	1,587.4	1.72%	11.8%
16	OGE Energy Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	7,497.2	0.92%	11.4%
17	Pepco Holdings	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	5,048.1	0.92%	11.4%
18	PG&E Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.55	8.8%	19,794.7	-0.37%	8.5%
19	Pub Sv Enterprise Grp	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	17,250.0	0.76%	11.3%
20	SCANA Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.65	9.7%	7,276.0	0.92%	10.6%
21	Sempra Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	21,193.3	-0.37%	10.6%
22	UIL Holdings	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	2,068.6	1.70%	11.8%
23	Vectren Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	2,992.4	1.14%	11.2%
24	Wisconsin Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	9,931.2	0.76%	10.0%
25	Xcel Energy, Inc.	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	14,743.7	0.76%	10.0%
	Average							**10.1%**			**11.0%**
	Midpoint (g)							**10.3%**			**10.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 13, 2012).

(b) Weighted average based on growth projections from The Value Line Investment Survey (Dec. 13, 2012), www.yahoo.com (retrieved Jan. 6, 2013), and www.zacks.com (retrieved Jan. 6, 2013).

(c) Average yield on 30-year Treasury bonds for 2014-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 24, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); & Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013).

(d) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).

(e) ($ millions) www.valueline.com (retrieved July 29, 2013).

(f) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(g) Average of low and high values.

EXPECTED EARNINGS APPROACH

GAS GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	AGL Resources	6.0%	1.021493	6.1%
2	Atmos Energy Corp.	8.5%	1.041342	8.9%
3	Laclede Group	13.0%	1.013458	13.2%
4	New Jersey Resources	12.5%	1.014717	12.7%
5	NiSource, Inc.	10.0%	1.011369	10.1%
6	Northwest Natural Gas	10.5%	1.019217	10.7%
7	Piedmont Natural Gas	11.0%	1.026134	11.3%
8	South Jersey Industries	15.5%	1.040387	16.1%
9	Southwest Gas Corp.	10.5%	1.031894	10.8%
10	WGL Holdings, Inc.	10.0%	1.018556	10.2%
	Average (d)			**11.6%**
	Midpoint (e)			**12.5%**

(a) The Value Line Investment Survey (Jun. 7, 2013).
(b) Adjustment to convert year-end return to an average rate of return from Avista/301, Schedule WEA-4.
(c) (a) x (b).
(d) Excludes highlighted figures.
(e) Average of low and high values.

COMBINATION GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	11.0%	1.024796	11.3%
2	Ameren Corp.	8.5%	1.013071	8.6%
3	Avista Corp.	8.5%	1.02038	8.7%
4	Black Hills Corp.	9.5%	1.020606	9.7%
5	CenterPoint Energy	13.0%	1.022577	13.3%
6	CMS Energy Corp.	13.0%	1.032269	13.4%
7	Consolidated Edison	9.0%	1.016102	9.1%
8	Dominion Resources	16.0%	1.036491	16.6%
9	DTE Energy Co.	9.0%	1.031058	9.3%
10	Duke Energy Corp.	8.0%	1.010572	8.1%
11	Empire District Elec	8.5%	1.021009	8.7%
12	Integrys Energy Group	9.0%	1.027631	9.2%
13	MGE Energy	11.5%	1.025604	11.8%
14	Northeast Utilities	9.5%	1.018153	9.7%
15	NorthWestern Corp.	9.5%	1.026147	9.7%
16	OGE Energy Corp.	11.0%	1.033849	11.4%
17	Pepco Holdings	8.0%	1.020227	8.2%
18	PG&E Corp.	8.5%	1.024174	8.7%
19	Pub Sv Enterprise Grp	10.0%	1.018688	10.2%
20	SCANA Corp.	9.5%	1.044433	9.9%
21	Sempra Energy	11.0%	1.02327	11.3%
22	UIL Holdings	9.0%	1.02653	9.2%
23	Vectren Corp.	11.5%	1.027373	11.8%
24	Wisconsin Energy	14.0%	1.016168	14.2%
25	Xcel Energy, Inc.	10.0%	1.027402	10.3%
	Average (d)			**10.5%**
	Midpoint (e)			**12.3%**

(a) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).

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

(c) (a) x (b).

(d) Excludes highlighted figures.

(e) Average of low and high values.

GAS GROUP

	Company	(a) Allowed ROE
1	AGL Resources	10.17%
2	Atmos Energy Corp.	11.72%
3	Laclede Group	NA
4	New Jersey Resources	10.30%
5	NiSource, Inc.	10.72%
6	Northwest Natural Gas	9.50%
7	Piedmont Natural Gas	10.40%
8	South Jersey Industries	10.30%
9	Southwest Gas Corp.	10.12%
10	WGL Holdings, Inc.	9.65%
	Average	**10.32%**
	Midpoint (b)	**10.61%**

(a) AUS Monthly Utility Report (Jul. 2013).
(b) Average of low and high values.

COMBINATION GROUP

	Company	(a) Allowed ROE
1	Alliant Energy	10.34%
2	Ameren Corp.	9.59%
3	Black Hills Corp.	10.72%
4	CenterPoint Energy	10.05%
5	CMS Energy Corp.	10.30%
6	Consolidated Edison	9.93%
7	Dominion Resources	10.52%
8	DTE Energy Co.	10.75%
9	Duke Energy Corp.	10.46%
10	Empire District Elec	NA
11	Integrys Energy Group	10.11%
12	MGE Energy	10.30%
13	Northeast Utilities	9.38%
14	NorthWestern Corp.	10.83%
15	OGE Energy Corp.	9.98%
16	Pepco Holdings	9.85%
17	PG&E Corp.	10.40%
18	Pub Sv Enterprise Grp	10.30%
19	SCANA Corp.	10.72%
20	Sempra Energy	11.48%
21	UIL Holdings	8.75%
22	Vectren Corp.	10.43%
23	Wisconsin Energy	10.43%
24	Xcel Energy, Inc.	10.60%
	Average	**10.27%**
	Midpoint (b)	**10.12%**

(a) AUS Monthly Utility Report (Jul. 2013).
(b) Average of low and high values.

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Church & Dwight	$ 61.74	$ 1.12	1.8%
2	Coca-Cola Co.	$ 40.51	$ 1.12	2.8%
3	Colgate-Palmolive	$ 58.17	$ 1.39	2.4%
4	Gen'l Mills	$ 49.40	$ 1.52	3.1%
5	Kellogg	$ 64.76	$ 1.84	2.8%
6	Kimberly-Clark	$ 97.82	$ 3.24	3.3%
7	McCormick & Co.	$ 71.30	$ 1.42	2.0%
8	McDonald's Corp.	$ 99.32	$ 3.08	3.1%
9	PepsiCo, Inc.	$ 82.43	$ 2.28	2.8%
10	Procter & Gamble	$ 78.66	$ 2.41	3.1%
11	Wal-Mart Stores	$ 75.64	$ 1.88	2.5%
	Average			**2.7%**

(a) Average of closing prices for 30 trading days ended July 19, 2013.
(b) The Value Line Investment Survey, Summary & Index (Jul. 19, 2013).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	V Line	IBES	Zacks
1	Church & Dwight	10.5%	11.8%	11.4%
2	Coca-Cola Co.	8.0%	7.9%	8.1%
3	Colgate-Palmolive	10.5%	9.1%	8.6%
4	Gen'l Mills	7.5%	7.9%	7.5%
5	Kellogg	8.0%	7.7%	7.7%
6	Kimberly-Clark	9.5%	7.8%	7.9%
7	McCormick & Co.	10.0%	13.0%	13.0%
8	McDonald's Corp.	8.0%	8.5%	9.3%
9	PepsiCo, Inc.	8.5%	8.5%	8.5%
10	Procter & Gamble	8.0%	7.6%	8.4%
11	Wal-Mart Stores	9.0%	9.3%	9.2%

(a) The Value Line Investment Survey (Apr. 26, May 3, May 31, & Jun. 28, 2013).
(b) www.finance.yahoo.com (retrieved July 23, 2013).
(c) www.zacks.com (retrieved July 23, 2013).

DCF COST OF EQUITY ESTIMATES

			(a)	(a)	(a)
			Earnings Growth		
	Company	Industry Group	V Line	IBES	Zacks
1	Church & Dwight	Household Products	12.3%	13.6%	13.3%
2	Coca-Cola Co.	Beverage	10.8%	10.7%	10.8%
3	Colgate-Palmolive	Household Products	12.9%	11.5%	11.0%
4	Gen'l Mills	Food Processing	10.6%	11.0%	10.6%
5	Kellogg	Food Processing	10.8%	10.5%	10.5%
6	Kimberly-Clark	Household Products	12.8%	11.1%	11.2%
7	McCormick & Co.	Food Processing	12.0%	15.0%	15.0%
8	McDonald's Corp.	Restaurant	11.1%	11.6%	12.4%
9	PepsiCo, Inc.	Beverage	11.3%	11.2%	11.3%
10	Procter & Gamble	Household Products	11.1%	10.7%	11.4%
11	Wal-Mart Stores	Retail Store	11.5%	11.8%	11.7%
	Average (b)		**11.6%**	**11.7%**	**11.8%**
	Midpoint (c)		**11.7%**	**12.8%**	**12.8%**

(a) Sum of dividend yield (Avista/301, Schedule WEA-14, p. 1) and respective growth rate (Avista/301, Schedule WEA-14, p. 2).

(b) Excludes highlighted figures.

(c) Average of low and high values.

RECOMMENDED ROE RANGE

	Range		
DCF	9.20%	--	10.20%
ECAPM	10.30%	--	11.30%
Utility Risk Premium	10.20%	--	11.10%
Recommended ROE Range	**9.90%**	--	**10.90%**
Flotation Cost Adjustment			
Dividend Yield	4.00%		4.00%
Flotation Cost Percentage	3.60%		3.60%
Adjustment	0.14%		0.14%
Adjusted Cost of Equity Range	**10.04%**	--	**11.04%**

SUMMARY OF RESULTS

	Gas Group		Combination Group	
DCF	**Average**	**Midpoint**	**Average**	**Midpoint**
Value Line	10.0%	10.3%	9.2%	11.1%
IBES	9.3%	10.0%	9.2%	10.0%
Zacks	8.5%	8.8%	9.0%	9.8%
br + sv	9.2%	9.9%	8.1%	8.6%
Empirical CAPM - 2013 Yield				
Unadjusted	10.3%	10.5%	10.5%	10.6%
Size Adjusted	11.8%	12.0%	11.3%	11.0%
Empirical CAPM - Projected Yield				
Unadjusted	10.7%	10.2%	10.7%	10.9%
Size Adjusted	12.1%	11.9%	11.6%	11.2%
Utility Risk Premium				
2013 Bond Yields	10.2%		--	
Projected Bond Yields	11.1%		--	

CHECKS OF REASONABLENESS

	Gas Group		Combination Group	
	Average	**Midpoint**	**Average**	**Midpoint**
CAPM - 2013 Yield				
Unadjusted	9.6%	9.8%	9.8%	10.0%
Size Adjusted	11.1%	10.6%	10.6%	10.3%
CAPM - Projected Yield				
Unadjusted	10.0%	10.2%	10.1%	10.3%
Size Adjusted	11.5%	11.7%	11.0%	10.6%
Expected Earnings	11.6%	12.5%	10.5%	12.3%
Allowed ROE	10.3%	10.6%	10.3%	10.1%
Non-Utility DCF				
Value Line	11.6%	11.7%		
IBES	11.7%	12.8%		
Zacks	11.8%	12.8%		

CAPITAL STRUCTURE

GAS GROUP

		At Fiscal Year-End 2012 (a)			Value Line Projected (b)		
	Company	**Debt**	**Preferred**	**Common Equity**	**Debt**	**Other**	**Common Equity**
1	AGL Resources	50.8%	0.0%	49.2%	51.5%	0.0%	48.5%
2	Atmos Energy Corp.	45.3%	0.0%	54.7%	49.0%	0.0%	51.0%
3	Laclede Group	37.7%	0.0%	62.3%	48.0%	0.0%	52.0%
4	New Jersey Resources	39.6%	0.0%	60.4%	34.5%	0.0%	65.5%
5	NiSource, Inc.	56.9%	0.0%	43.1%	58.0%	0.0%	42.0%
6	Northwest Natural Gas	48.5%	0.0%	51.5%	48.0%	0.0%	52.0%
7	Piedmont Natural Gas	48.7%	0.0%	51.3%	48.5%	0.0%	51.5%
8	South Jersey Industries	46.0%	0.0%	54.0%	42.0%	0.0%	58.0%
9	Southwest Gas Corp.	50.2%	0.0%	49.8%	48.5%	0.0%	51.5%
10	WGL Holdings, Inc.	31.2%	1.5%	67.3%	28.0%	1.5%	70.5%
	Average	**45.5%**	**0.1%**	**54.4%**	**45.6%**	**0.2%**	**54.3%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Jun. 7, 2013).

COMBINATION GROUP

		At Fiscal Year-End 2012 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	Alliant Energy	48.4%	3.2%	48.4%	46.0%	2.5%	51.5%
2	Ameren Corp.	50.8%	0.0%	49.2%	44.0%	1.0%	55.0%
3	Avista Corp.	50.1%	0.0%	49.9%	48.5%	0.0%	51.5%
4	Black Hills Corp.	45.8%	0.0%	54.2%	51.5%	0.0%	48.5%
5	CenterPoint Energy	61.0%	0.0%	39.0%	56.5%	0.0%	43.5%
6	CMS Energy Corp.	69.1%	0.0%	30.9%	62.0%	0.0%	38.0%
7	Consolidated Edison	47.6%	0.0%	52.4%	47.0%	0.0%	53.0%
8	Dominion Resources	64.2%	0.0%	35.8%	58.0%	0.5%	41.5%
9	DTE Energy Co.	50.4%	0.0%	49.6%	50.0%	0.0%	50.0%
10	Duke Energy Corp.	48.5%	0.1%	51.4%	52.0%	0.0%	48.0%
11	Empire District Elec	49.1%	0.0%	50.9%	51.5%	0.0%	48.5%
12	Integrys Energy Group	42.6%	0.0%	57.4%	46.5%	0.5%	53.0%
13	MGE Energy	38.4%	0.0%	61.6%	36.0%	0.0%	64.0%
14	Northeast Utilities	45.9%	0.9%	53.2%	46.5%	0.5%	53.0%
15	NorthWestern Corp.	53.0%	0.0%	47.0%	45.5%	0.0%	54.5%
16	OGE Energy Corp.	48.1%	0.0%	51.9%	43.5%	0.0%	56.5%
17	Pepco Holdings	49.2%	1.0%	49.8%	50.0%	0.0%	50.0%
18	PG&E Corp.	44.7%	0.0%	55.3%	50.0%	1.0%	49.0%
19	Pub Sv Enterprise Grp	48.7%	0.0%	51.3%	44.0%	0.0%	56.0%
20	SCANA Corp.	55.2%	0.0%	44.8%	53.5%	0.0%	46.5%
21	Sempra Energy	53.6%	0.1%	46.3%	54.0%	0.5%	45.5%
22	UIL Holdings	53.1%	10.9%	36.0%	54.5%	0.0%	45.5%
23	Vectren Corp.	52.1%	0.0%	47.9%	48.5%	0.0%	51.5%
	Average	**50.9%**	**0.7%**	**48.4%**	**49.5%**	**0.3%**	**50.2%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	AGL Resources	$ 43.28	$ 1.88	4.3%
2	Atmos Energy Corp.	$ 43.52	$ 1.42	3.3%
3	Laclede Group	$ 46.37	$ 1.70	3.7%
4	New Jersey Resources	$ 45.95	$ 1.60	3.5%
5	NiSource, Inc.	$ 29.39	$ 0.98	3.3%
6	Northwest Natural Gas	$ 44.13	$ 1.82	4.1%
7	Piedmont Natural Gas	$ 34.14	$ 1.24	3.6%
8	South Jersey Industries	$ 59.55	$ 1.85	3.1%
9	Southwest Gas Corp.	$ 49.46	$ 1.35	2.7%
10	WGL Holdings, Inc.	$ 44.45	$ 1.68	3.8%
	Average			**3.5%**

(a) Average of closing prices for 30 trading days ended Jun. 7, 2013.
(b) The Value Line Investment Survey, Summary & Index (Jun. 7, 2013).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	AGL Resources	9.0%	NA	3.5%	5.7%
2	Atmos Energy Corp.	5.5%	6.0%	6.0%	4.9%
3	Laclede Group	5.5%	8.9%	3.0%	7.3%
4	New Jersey Resources	2.0%	4.0%	4.0%	4.8%
5	NiSource, Inc.	8.5%	7.9%	6.7%	4.7%
6	Northwest Natural Gas	5.0%	3.8%	3.8%	5.0%
7	Piedmont Natural Gas	3.0%	5.0%	4.3%	4.0%
8	South Jersey Industries	8.0%	6.0%	6.0%	9.2%
9	Southwest Gas Corp.	7.0%	5.5%	5.3%	7.1%
10	WGL Holdings, Inc.	3.5%	5.3%	5.3%	3.9%

(a) The Value Line Investment Survey (Jun. 7, 2013).
(b) www.finance.yahoo.com (retrieved Jun. 27, 2013).
(c) www.zacks.com (retrieved Jun. 27, 2013).
(d) See Avista/301, Schedule WEA-4.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	AGL Resources	13.3%	NA	7.8%	10.1%
2	Atmos Energy Corp.	8.8%	9.3%	9.3%	8.2%
3	Laclede Group	9.2%	12.6%	6.7%	11.0%
4	New Jersey Resources	5.5%	7.5%	7.5%	8.3%
5	NiSource, Inc.	11.8%	11.2%	10.0%	8.1%
6	Northwest Natural Gas	9.1%	7.9%	7.9%	9.1%
7	Piedmont Natural Gas	6.6%	8.6%	7.9%	7.6%
8	South Jersey Industries	11.1%	9.1%	9.1%	12.3%
9	Southwest Gas Corp.	9.7%	8.2%	8.0%	9.9%
10	WGL Holdings, Inc.	7.3%	9.0%	9.1%	7.7%
	Average (b)	**10.0%**	**9.3%**	**8.5%**	**9.2%**
	Midpoint (c)	**10.3%**	**10.0%**	**8.8%**	**9.9%**

(a) Sum of dividend yield (Avista/301, Schedule WEA-3, p. 1) and respective growth rate (Avista/301, Schedule WEA-3, p. 2).

(b) Excludes highlighted figures.

(c) Average of low and high values.

DCF MODEL - GAS GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2017					Adjustment			"sv" Factor			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	AGL Resources	$4.10	$2.04	$36.05	50.2%	11.4%	1.0215	11.6%	5.8%	(0.0026)	0.4232	-0.11%	**5.7%**
2	Atmos Energy Corp.	$3.00	$1.50	$34.65	50.0%	8.7%	1.0413	9.0%	4.5%	0.0309	0.1338	0.41%	**4.9%**
3	Laclede Group	$3.75	$1.82	$28.65	51.5%	13.1%	1.0135	13.3%	6.8%	0.0125	0.3870	0.48%	**7.3%**
4	New Jersey Resources	$2.95	$1.72	$23.50	41.7%	12.6%	1.0147	12.7%	5.3%	(0.0127)	0.4125	-0.53%	**4.8%**
5	NiSource, Inc.	$1.90	$1.10	$18.80	42.1%	10.1%	1.0114	10.2%	4.3%	0.0137	0.3200	0.44%	**4.7%**
6	Northwest Natural Gas	$3.30	$2.00	$31.70	39.4%	10.4%	1.0192	10.6%	4.2%	0.0157	0.4982	0.78%	**5.0%**
7	Piedmont Natural Gas	$1.90	$1.39	$17.60	26.8%	10.8%	1.0261	11.1%	3.0%	0.0203	0.5000	1.02%	**4.0%**
8	South Jersey Industries	$4.60	$2.45	$36.00	46.7%	12.8%	1.0404	13.3%	6.2%	0.0555	0.5300	2.94%	**9.2%**
9	Southwest Gas Corp.	$3.75	$1.60	$36.00	57.3%	10.4%	1.0319	10.7%	6.2%	0.0258	0.3739	0.96%	**7.1%**
10	WGL Holdings, Inc.	$2.95	$1.83	$29.80	38.0%	9.9%	1.0186	10.1%	3.8%	0.0027	0.2763	0.07%	**3.9%**

DCF MODEL - GAS GROUP

BR+SV GROWTH RATE

		2012			2017			Chg	2017 Price				Common Shares		
		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
	Company	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Equity**	**High**	**Low**	**Avg.**	**M/B**	**2012**	**2017**	**Growth**
1	AGL Resources	50.5%	$6,716	$3,392	48.5%	$8,670	$4,205	4.4%	$70.00	$55.00	$62.50	1.734	117.88	117.00	-0.15%
2	Atmos Energy Corp.	54.7%	$4,316	$2,361	51.0%	$7,000	$3,570	8.6%	$50.00	$35.00	$42.50	1.154	90.24	103.00	2.68%
3	Laclede Group	64.0%	$941	$602	52.0%	$1,325	$689	2.7%	$65.00	$50.00	$57.50	1.631	22.62	23.50	0.77%
4	New Jersey Resources	60.8%	$1,339	$814	65.5%	$1,440	$943	3.0%	$45.00	$35.00	$40.00	1.702	41.53	40.00	-0.75%
5	NiSource, Inc.	44.9%	$12,373	$5,555	42.0%	$14,820	$6,224	2.3%	$35.00	$25.00	$30.00	1.471	310.28	325.00	0.93%
6	Northwest Natural Gas	51.5%	$1,425	$734	52.0%	$1,710	$889	3.9%	$60.00	$50.00	$55.00	1.993	26.92	28.00	0.79%
7	Piedmont Natural Gas	51.3%	$2,002	$1,027	51.5%	$2,590	$1,334	5.4%	$40.00	$30.00	$35.00	2.000	72.25	76.00	1.02%
8	South Jersey Industries	55.0%	$1,338	$736	58.0%	$1,900	$1,102	8.4%	$75.00	$55.00	$65.00	2.128	31.65	36.00	2.61%
9	Southwest Gas Corp.	50.8%	$2,579	$1,310	51.5%	$3,500	$1,803	6.6%	$70.00	$45.00	$57.50	1.597	46.15	50.00	1.62%
10	WGL Holdings, Inc.	67.5%	$1,887	$1,274	70.5%	$2,175	$1,533	3.8%	$50.00	$40.00	$45.00	1.382	51.50	52.00	0.19%

(a) The Value Line Investment Survey (Jun. 7, 2013).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2017 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2017 BVPS.

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Alliant Energy	$ 50.19	$ 1.92	3.8%
2	Ameren Corp.	$ 34.59	$ 1.60	4.6%
3	Avista Corp.	$ 27.42	$ 1.25	4.6%
4	Black Hills Corp.	$ 48.17	$ 1.54	3.2%
5	CenterPoint Energy	$ 23.53	$ 0.84	3.6%
6	CMS Energy Corp.	$ 27.53	$ 1.05	3.8%
7	Consolidated Edison	$ 58.44	$ 2.48	4.2%
8	Dominion Resources	$ 57.40	$ 2.28	4.0%
9	DTE Energy Co.	$ 68.04	$ 2.62	3.9%
10	Duke Energy Corp.	$ 68.61	$ 3.12	4.5%
11	Empire District Elec	$ 22.15	$ 1.00	4.5%
12	Integrys Energy Group	$ 58.46	$ 2.72	4.7%
13	MGE Energy	$ 54.74	$ 1.62	3.0%
14	Northeast Utilities	$ 42.50	$ 1.49	3.5%
15	NorthWestern Corp.	$ 41.07	$ 1.54	3.7%
16	OGE Energy Corp.	$ 68.74	$ 0.88	1.3%
17	Pepco Holdings	$ 20.96	$ 1.08	5.2%
18	PG&E Corp.	$ 45.59	$ 1.82	4.0%
19	Pub Sv Enterprise Grp	$ 33.38	$ 1.45	4.3%
20	SCANA Corp.	$ 50.79	$ 2.04	4.0%
21	Sempra Energy	$ 81.07	$ 2.58	3.2%
22	UIL Holdings	$ 39.63	$ 1.73	4.4%
23	Vectren Corp.	$ 34.62	$ 1.44	4.2%
24	Wisconsin Energy	$ 41.66	$ 1.53	3.7%
25	Xcel Energy, Inc.	$ 29.32	$ 1.13	3.9%
	Average			**3.9%**

(a) Average of closing prices for 30 trading days ended June 21, 2013.
(b) The Value Line Investment Survey, Summary & Index (Aug. 2, 2013).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	Alliant Energy	5.0%	5.9%	5.7%	5.1%
2	Ameren Corp.	-0.5%	-1.2%	2.5%	2.8%
3	Avista Corp.	4.0%	4.5%	4.3%	2.9%
4	Black Hills Corp.	11.5%	5.0%	5.0%	4.1%
5	CenterPoint Energy	4.5%	4.8%	5.3%	5.1%
6	CMS Energy Corp.	5.5%	5.9%	6.1%	5.0%
7	Consolidated Edison	2.5%	1.7%	3.3%	3.5%
8	Dominion Resources	6.0%	7.0%	5.9%	6.1%
9	DTE Energy Co.	4.0%	4.7%	4.7%	3.7%
10	Duke Energy Corp.	4.0%	3.9%	3.1%	2.6%
11	Empire District Elec	5.0%	3.0%	3.0%	2.9%
12	Integrys Energy Group	3.5%	5.5%	5.0%	2.9%
13	MGE Energy	4.5%	4.0%	4.0%	5.7%
14	Northeast Utilities	8.0%	7.4%	7.9%	4.4%
15	NorthWestern Corp.	4.5%	4.0%	5.0%	4.1%
16	OGE Energy Corp.	5.0%	4.6%	5.6%	-4.0%
17	Pepco Holdings	6.0%	4.2%	5.1%	2.9%
18	PG&E Corp.	2.5%	2.3%	1.8%	3.2%
19	Pub Sv Enterprise Grp	-2.5%	-2.7%	-0.1%	3.9%
20	SCANA Corp.	4.5%	4.8%	4.7%	5.3%
21	Sempra Energy	4.5%	5.0%	5.0%	5.2%
22	UIL Holdings	4.0%	8.1%	8.0%	3.0%
23	Vectren Corp.	6.5%	5.0%	5.0%	5.3%
24	Wisconsin Energy	5.5%	4.9%	5.2%	4.7%
25	Xcel Energy, Inc.	4.5%	5.1%	5.0%	4.4%

(a) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).
(b) www.finance.yahoo.com (retrieved Jul. 29, 2013).
(c) www.zacks.com (retrieved Jul. 29, 2013).
(d) See Avista/301, Schedule WEA-6.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Alliant Energy	8.8%	9.7%	9.5%	8.9%
2	Ameren Corp.	4.1%	3.4%	7.2%	7.5%
3	Avista Corp.	8.6%	9.1%	8.9%	7.5%
4	Black Hills Corp.	14.7%	8.2%	8.2%	7.3%
5	CenterPoint Energy	8.1%	8.4%	8.9%	8.7%
6	CMS Energy Corp.	9.3%	9.7%	9.9%	8.9%
7	Consolidated Edison	6.7%	6.0%	7.5%	7.7%
8	Dominion Resources	10.0%	11.0%	9.9%	10.1%
9	DTE Energy Co.	7.9%	8.5%	8.5%	7.6%
10	Duke Energy Corp.	8.5%	8.4%	7.6%	7.1%
11	Empire District Elec	9.5%	7.5%	7.5%	7.4%
12	Integrys Energy Group	8.2%	10.2%	9.7%	7.6%
13	MGE Energy	7.5%	7.0%	7.0%	8.7%
14	Northeast Utilities	11.5%	10.9%	11.4%	7.9%
15	NorthWestern Corp.	8.2%	7.7%	8.7%	7.9%
16	OGE Energy Corp.	6.3%	5.8%	6.9%	-2.7%
17	Pepco Holdings	11.2%	9.4%	10.3%	8.0%
18	PG&E Corp.	6.5%	6.3%	5.8%	7.2%
19	Pub Sv Enterprise Grp	1.8%	1.7%	4.2%	8.2%
20	SCANA Corp.	8.5%	8.8%	8.7%	9.3%
21	Sempra Energy	7.7%	8.1%	8.1%	8.4%
22	UIL Holdings	8.4%	12.4%	12.4%	7.3%
23	Vectren Corp.	10.7%	9.2%	9.2%	9.5%
24	Wisconsin Energy	9.2%	8.6%	8.9%	8.4%
25	Xcel Energy, Inc.	8.4%	8.9%	8.8%	8.2%
	Average (b)	**9.2%**	**9.2%**	**9.0%**	**8.1%**
	Midpoint (c)	**11.1%**	**10.0%**	**9.8%**	**8.6%**

(a) Sum of dividend yield (Avista/301, Schedule WEA-5, p. 1) and respective growth rate (Avista/301, Schedule WEA-5, p. 2).

(b) Excludes highlighted figures.

(c) Average of low and high values.

DCF MODEL - COMBINATION GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		-------------- 2017	-------------				Adjustment			--------- "sv" Factor	--------		
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$3.80	$2.20	$34.50	42.1%	11.0%	1.0248	11.3%	4.8%	0.0122	0.2737	0.33%	**5.1%**
2	Ameren Corp.	$2.50	$1.70	$29.50	32.0%	8.5%	1.0131	8.6%	2.7%	0.0110	0.0923	0.10%	**2.8%**
3	Avista Corp.	$2.00	$1.40	$24.00	30.0%	8.3%	1.0204	8.5%	2.6%	0.0170	0.2000	0.34%	**2.9%**
4	Black Hills Corp.	$3.00	$1.70	$33.25	43.3%	9.0%	1.0206	9.2%	4.0%	0.0075	0.1133	0.09%	**4.1%**
5	CenterPoint Energy	$1.60	$1.00	$12.50	37.5%	12.8%	1.0226	13.1%	4.9%	0.0047	0.4444	0.21%	**5.1%**
6	CMS Energy Corp.	$2.00	$1.30	$16.00	35.0%	12.5%	1.0323	12.9%	4.5%	0.0127	0.4182	0.53%	**5.0%**
7	Consolidated Edison	$4.25	$2.62	$47.75	38.4%	8.9%	1.0161	9.0%	3.5%	0.0001	0.1696	0.00%	**3.5%**
8	Dominion Resources	$4.00	$2.75	$25.50	31.3%	15.7%	1.0365	16.3%	5.1%	0.0185	0.5565	1.03%	**6.1%**
9	DTE Energy Co.	$4.75	$3.15	$53.00	33.7%	9.0%	1.0311	9.2%	3.1%	0.0260	0.2429	0.63%	**3.7%**
10	Duke Energy Corp.	$5.00	$3.35	$64.25	33.0%	7.8%	1.0106	7.9%	2.6%	0.0017	0.0115	0.00%	**2.6%**
11	Empire District Elec	$1.70	$1.20	$19.25	29.4%	8.8%	1.0210	9.0%	2.7%	0.0196	0.1250	0.25%	**2.9%**
12	Integrys Energy Group	$4.00	$2.80	$46.50	30.0%	8.6%	1.0276	8.8%	2.7%	0.0226	0.1143	0.26%	**2.9%**
13	MGE Energy	$3.60	$1.86	$31.90	48.3%	11.3%	1.0256	11.6%	5.6%	0.0029	0.4200	0.12%	**5.7%**
14	Northeast Utilities	$3.25	$1.80	$34.50	44.6%	9.4%	1.0182	9.6%	4.3%	0.0041	0.2333	0.10%	**4.4%**
15	NorthWestern Corp.	$3.00	$1.80	$31.25	40.0%	9.6%	1.0261	9.9%	3.9%	0.0113	0.1667	0.19%	**4.1%**
16	OGE Energy Corp.	$2.25	$1.05	$19.00	53.3%	11.8%	1.0338	12.2%	6.5%	(0.2298)	0.4571	-10.50%	**-4.0%**
17	Pepco Holdings	$1.70	$1.16	$21.50	31.8%	7.9%	1.0202	8.1%	2.6%	0.0237	0.1224	0.29%	**2.9%**
18	PG&E Corp.	$3.00	$2.10	$35.25	30.0%	8.5%	1.0242	8.7%	2.6%	0.0252	0.2167	0.55%	**3.2%**
19	Pub Sv Enterprise Grp	$2.50	$1.52	$25.75	39.2%	9.7%	1.0187	9.9%	3.9%	0.0001	0.2077	0.00%	**3.9%**
20	SCANA Corp.	$4.00	$2.25	$41.50	43.8%	9.6%	1.0444	10.1%	4.4%	0.0430	0.2095	0.90%	**5.3%**
21	Sempra Energy	$5.50	$3.00	$52.00	45.5%	10.6%	1.0233	10.8%	4.9%	0.0093	0.3290	0.30%	**5.2%**
22	UIL Holdings	$2.55	$1.73	$28.45	32.2%	9.0%	1.0265	9.2%	3.0%	0.0007	0.2888	0.02%	**3.0%**
23	Vectren Corp.	$2.60	$1.60	$23.00	38.5%	11.3%	1.0274	11.6%	4.5%	0.0199	0.4250	0.84%	**5.3%**
24	Wisconsin Energy	$3.00	$2.00	$21.25	33.3%	14.1%	1.0162	14.3%	4.8%	(0.0010)	0.5278	-0.05%	**4.7%**
25	Xcel Energy, Inc.	$2.25	$1.35	$23.00	40.0%	9.8%	1.0274	10.1%	4.0%	0.0141	0.2333	0.33%	**4.4%**

DCF MODEL - COMBINATION GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2012			2017			Chg	2017 Price				Common Shares		
	Company	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Equity**	**High**	**Low**	**Avg.**	**M/B**	**2012**	**2017**	**Growth**
1	Alliant Energy	48.4%	$6,477	$3,135	51.5%	$7,800	$4,017	5.1%	$55.00	$40.00	$47.50	1.377	110.99	116.00	0.89%
2	Ameren Corp.	49.4%	$13,384	$6,612	55.0%	$13,700	$7,535	2.6%	$40.00	$25.00	$32.50	1.102	242.65	255.00	1.00%
3	Avista Corp.	49.2%	$2,561	$1,260	51.5%	$3,000	$1,545	4.2%	$35.00	$25.00	$30.00	1.250	59.81	64.00	1.36%
4	Black Hills Corp.	56.8%	$2,171	$1,233	48.5%	$3,125	$1,516	4.2%	$45.00	$30.00	$37.50	1.128	44.21	45.70	0.67%
5	CenterPoint Energy	34.0%	$12,658	$4,304	43.5%	$12,400	$5,394	4.6%	$25.00	$20.00	$22.50	1.800	427.44	433.00	0.26%
6	CMS Energy Corp.	31.6%	$10,101	$3,192	38.0%	$11,600	$4,408	6.7%	$35.00	$20.00	$27.50	1.719	264.10	274.00	0.74%
7	Consolidated Edison	54.1%	$21,933	$11,866	53.0%	$26,300	$13,939	3.3%	$65.00	$50.00	$57.50	1.204	292.87	293.00	0.01%
8	Dominion Resources	38.2%	$27,676	$10,572	41.5%	$36,700	$15,231	7.6%	$65.00	$50.00	$57.50	2.255	576.00	600.00	0.82%
9	DTE Energy Co.	51.2%	$14,387	$7,366	50.0%	$20,100	$10,050	6.4%	$80.00	$60.00	$70.00	1.321	172.35	190.00	1.97%
10	Duke Energy Corp.	52.9%	$77,307	$40,895	48.0%	$94,700	$45,456	2.1%	$75.00	$55.00	$65.00	1.012	704.00	710.00	0.17%
11	Empire District Elec	50.9%	$1,409	$717	48.5%	$1,825	$885	4.3%	$25.00	$19.00	$22.00	1.143	42.48	46.25	1.72%
12	Integrys Energy Group	60.4%	$5,009	$3,025	53.0%	$7,525	$3,988	5.7%	$60.00	$45.00	$52.50	1.129	77.90	86.00	2.00%
13	MGE Energy	61.8%	$938	$580	64.0%	$1,170	$749	5.3%	$60.00	$50.00	$55.00	1.724	23.30	23.50	0.17%
14	Northeast Utilities	55.4%	$16,675	$9,238	53.0%	$20,900	$11,077	3.7%	$50.00	$40.00	$45.00	1.304	314.05	319.00	0.31%
15	NorthWestern Corp.	46.2%	$2,021	$934	54.5%	$2,225	$1,213	5.4%	$45.00	$30.00	$37.50	1.200	37.22	39.00	0.94%
16	OGE Energy Corp.	49.3%	$5,616	$2,769	56.5%	$6,875	$3,884	7.0%	$40.00	$30.00	$35.00	1.842	197.60	101.50	-12.47%
17	Pepco Holdings	52.7%	$8,432	$4,444	50.0%	$10,880	$5,440	4.1%	$30.00	$19.00	$24.50	1.140	230.02	255.00	2.08%
18	PG&E Corp.	50.4%	$25,956	$13,082	49.0%	$34,000	$16,660	5.0%	$55.00	$35.00	$45.00	1.277	430.72	475.00	1.98%
19	Pub Sv Enterprise Grp	61.7%	$17,467	$10,777	56.0%	$23,200	$12,992	3.8%	$35.00	$30.00	$32.50	1.262	505.89	506.00	0.00%
20	SCANA Corp.	45.6%	$9,103	$4,151	46.5%	$13,925	$6,475	9.3%	$60.00	$45.00	$52.50	1.265	132.00	156.00	3.40%
21	Sempra Energy	46.7%	$22,002	$10,275	45.5%	$28,500	$12,968	4.8%	$90.00	$65.00	$77.50	1.490	242.37	250.00	0.62%
22	UIL Holdings	41.1%	$2,717	$1,117	45.5%	$3,200	$1,456	5.5%	$45.00	$35.00	$40.00	1.406	50.87	51.00	0.05%
23	Vectren Corp.	49.6%	$3,080	$1,527	51.5%	$3,900	$2,009	5.6%	$45.00	$35.00	$40.00	1.739	82.20	87.00	1.14%
24	Wisconsin Energy	48.0%	$8,619	$4,137	49.5%	$9,825	$4,863	3.3%	$50.00	$40.00	$45.00	2.118	229.04	228.50	-0.05%
25	Xcel Energy, Inc.	46.7%	$19,018	$8,881	49.5%	$23,600	$11,682	5.6%	$35.00	$25.00	$30.00	1.304	487.96	515.00	1.08%

(a) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2017 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2017 BVPS.

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP [1]	Beta	Weight	RP [2]	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.75	75%	5.3%	7.6%	10.8%	4,944.63	0.92%	11.8%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.70	75%	4.9%	7.3%	10.5%	3,520.12	1.14%	11.6%
3	Laclede Group	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.60	75%	4.2%	6.6%	9.8%	1,008.07	1.73%	11.5%
4	New Jersey Resources	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	1,751.25	1.72%	11.9%
5	NiSource, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.80	75%	5.6%	8.0%	11.2%	8,612.30	0.76%	12.0%
6	Northwest Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.60	75%	4.2%	6.6%	9.8%	1,131.28	1.73%	11.5%
7	Piedmont Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	2,487.40	1.70%	11.8%
8	South Jersey Industries	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	1,765.84	1.72%	11.9%
9	Southwest Gas Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.75	75%	5.3%	7.6%	10.8%	2,119.83	1.70%	12.5%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	25%	2.4%	0.65	75%	4.6%	6.9%	10.1%	2,160.11	1.70%	11.8%
	Average												**10.3%**			**11.8%**
	Midpoint (n)												**10.5%**			**12.0%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jun. 21, 2013).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 15, 2013).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2013 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); & Blue Chip Financial Forecasts, Vol. 32, No. 6 (Jun. 1, 2013).
(e) (c) - (d).
(f) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(g) (e) x weighting factor.
(h) The Value Line Investment Survey (Jun. 7, 2013).
(i) (e) x (h) x weighting factor.
(j) (d) + (g) + (i).
(k) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
(l) *Morningstar*, "2013 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2013).
(m) (g) + (h).
(n) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	*RP* [1]	Beta	Weight	*RP* [2]	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.1%	4,944.63	0.92%	12.0%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.70	75%	4.3%	6.3%	10.8%	3,520.12	1.14%	11.9%
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5	NiSource, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.80	75%	4.9%	6.9%	11.4%	8,612.30	0.76%	12.1%
6	Northwest Natural Gas	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.60	75%	3.6%	5.7%	10.2%	1,131.28	1.73%	11.9%
7	Piedmont Natural Gas	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.65	75%	3.9%	6.0%	10.5%	2,487.40	1.70%	12.2%
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9	Southwest Gas Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.75	75%	4.6%	6.6%	11.1%	2,119.83	1.70%	12.8%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	25%	2.0%	0.65	75%	3.9%	6.0%	10.5%	2,160.11	1.70%	12.2%
	Average												**10.7%**			**12.1%**
	Midpoint (n)												**10.2%**			**11.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jun. 21, 2013).
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(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2014-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); & Blue Chip Financial Forecasts, Vol. 32, No. 6 (Jun. 1, 2013).
(e) (c) - (d).
(f) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(g) (e) x weighting factor.
(h) The Value Line Investment Survey (Jun. 7, 2013).
(i) (e) x (h) x weighting factor.
(j) (d) + (g) + (i).
(k) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
(l) *Morningstar*, "2013 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2013).
(m) (g) + (h).
(n) Average of low and high values.

EMPIRICAL CAPM - 2013 BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	5,937.7	0.92%	11.4%
2	Ameren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	8,665.7	0.76%	11.9%
3	Avista Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	1,724.3	1.72%	12.2%
4	Black Hills Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	2,333.5	1.70%	12.9%
5	CenterPoint Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	10,588.8	0.76%	11.9%
6	CMS Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	7,495.4	0.92%	11.7%
7	Consolidated Edison	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	17,408.1	0.76%	10.5%
8	Dominion Resources	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	10.1%	34,290.9	-0.37%	9.7%
9	DTE Energy Co.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	12,180.0	0.76%	11.6%
10	Duke Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	49,843.6	-0.37%	9.4%
11	Empire District Elec	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	10.1%	1,020.5	1.73%	11.8%
12	Integrys Energy Group	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.90	75%	6.4%	8.8%	11.9%	4,908.0	0.92%	12.8%
13	MGE Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	1,382.2	1.72%	11.5%
14	Northeast Utilities	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	13,958.6	0.76%	11.2%
15	NorthWestern Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	1,587.4	1.72%	12.2%
16	OGE Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	7,497.2	0.92%	11.7%
17	Pepco Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	5,048.1	0.92%	11.7%
18	PG&E Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.55	75%	3.9%	6.3%	9.4%	19,794.7	-0.37%	9.0%
19	Pub Sv Enterprise Grp	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.75	75%	5.3%	7.7%	10.8%	17,250.0	0.76%	11.6%
20	SCANA Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.65	75%	4.6%	7.0%	10.1%	7,276.0	0.92%	11.0%
21	Sempra Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.80	75%	5.7%	8.1%	11.2%	21,193.3	-0.37%	10.8%
22	UIL Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	2,068.6	1.70%	12.2%
23	Vectren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.70	75%	5.0%	7.4%	10.5%	2,992.4	1.14%	11.6%
24	Wisconsin Energy	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	9,931.2	0.76%	10.5%
25	Xcel Energy, Inc.	2.5%	10.1%	12.6%	3.1%	9.5%	25%	2.4%	0.60	75%	4.3%	6.6%	9.8%	14,743.7	0.76%	10.5%
	Average												**10.5%**			**11.3%**
	Midpoint (h)												**10.6%**			**11.0%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Apr. 15, 2012).
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(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).
(f) ($ millions) www.valueline.com (retrieved July 29, 2013).
(g) *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).
(h) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Empirical	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.5%	10.1%	12.6%	4.2%	8.4%	25%	2.1%	0.70	75%	4.4%	6.5%	10.7%	5,937.7	0.92%	11.6%
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8	Dominion Resources	2.5%	10.1%	12.6%	4.2%	8.4%	25%	2.1%	0.65	75%	4.1%	6.2%	10.4%	34,290.9	-0.37%	10.0%
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25	Xcel Energy, Inc.	2.5%	10.1%	12.6%	4.2%	8.4%	25%	2.1%	0.60	75%	3.8%	5.9%	10.1%	14,743.7	0.76%	10.8%
	Average												**10.7%**			**11.6%**
	Midpoint (h)												**10.9%**			**11.2%**

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(g) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).
(h) Average of low and high values.

2013 BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.69%
(b)	2013 Single-A Utility Bond Yield	4.50%
	Change in Bond Yield	-4.19%
(c)	Risk Premium/Interest Rate Relationship	-0.4592
	Adjustment to Average Risk Premium	1.92%
(a)	Average Risk Premium over Study Period	3.25%
	Adjusted Risk Premium	**5.17%**
Implied Cost of Equity		
(b)	2013 BBB Utility Bond Yield	5.01%
	Adjusted Equity Risk Premium	5.17%
	Risk Premium Cost of Equity	**10.18%**

(a) Avista/301, Schedule WEA-9, Avera/Page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(c) Avista/301, Schedule WEA-9, Avera/Page 4.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Projected Single-A Utility Bond Yield 2014-17	6.21%
	Change in Bond Yield	-2.48%
(c)	Risk Premium/Interest Rate Relationship	-0.4592
	Adjustment to Average Risk Premium	1.14%
(a)	Average Risk Premium over Study Period	3.25%
	Adjusted Risk Premium	**4.39%**

Implied Cost of Equity

(b)	Projected BBB Utility Bond Yield 2014-17	6.72%
	Adjusted Equity Risk Premium	4.39%
	Risk Premium Cost of Equity	**11.11%**

(a) Avista/301, Schedule WEA-9, Avera/Page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(c) Avista/301, Schedule WEA-9, Avera/Page 4.

AUTHORIZED RETURNS

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

Year	Qtr.		(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1997	1		11.31%	7.76%	3.55%
	2		11.70%	7.88%	3.82%
	3		12.00%	7.49%	4.51%
	4	(c)	11.01%	7.25%	3.76%
1998	2		11.37%	7.12%	4.25%
	3		11.41%	6.99%	4.42%
	4		11.69%	6.97%	4.72%
1999	1		10.82%	7.11%	3.71%
	2	(c)	10.82%	7.48%	3.34%
	4		10.33%	8.05%	2.28%
2000	1		10.71%	8.29%	2.42%
	2		11.08%	8.45%	2.63%
	3		11.33%	8.25%	3.08%
	4		12.50%	8.03%	4.47%
2001	1		11.16%	7.74%	3.42%
	2	(c)	10.75%	7.93%	2.82%
	4		10.65%	7.68%	2.97%
2002	1		10.67%	7.65%	3.02%
	2		11.64%	7.50%	4.14%
	3		11.50%	7.19%	4.31%
	4		10.78%	7.15%	3.63%
2003	1		11.38%	6.93%	4.45%
	2		11.36%	6.40%	4.96%
	3		10.61%	6.64%	3.97%
	4		10.84%	6.35%	4.49%
2004	1		11.10%	6.09%	5.01%
	2		10.25%	6.48%	3.77%
	3		10.37%	6.13%	4.24%
	4		10.66%	5.94%	4.72%
2005	1		10.65%	5.74%	4.91%
	2		10.52%	5.52%	5.00%
	3		10.47%	5.51%	4.96%
	4		10.40%	5.82%	4.58%
2006	1		10.63%	5.85%	4.78%
	2		10.50%	6.37%	4.13%
	3		10.45%	6.19%	4.26%
	4		10.14%	5.86%	4.28%
2007	1		10.44%	5.90%	4.54%
	2		10.12%	6.09%	4.03%
	3		10.03%	6.22%	3.81%
	4		10.27%	6.08%	4.19%
2008	1		10.38%	6.15%	4.23%
	2		10.17%	6.32%	3.85%
	3		10.49%	6.42%	4.07%
	4		10.34%	7.23%	3.11%
2009	1		10.24%	6.37%	3.87%
	2		10.11%	6.39%	3.72%
	3		9.88%	5.74%	4.14%
	4		10.27%	5.66%	4.61%
2010	1		10.24%	5.83%	4.41%
	2		9.99%	5.61%	4.38%
	3		9.93%	5.09%	4.84%
	4		10.09%	5.34%	4.75%
2011	1		10.10%	5.60%	4.50%
	2		9.85%	5.38%	4.47%
	3		9.65%	4.81%	4.84%
	4		9.88%	4.37%	5.51%
2012	1		9.63%	4.39%	5.24%
	2		9.83%	4.23%	5.60%
	3		9.75%	3.98%	5.77%
	4		10.07%	3.93%	6.14%
2013	1		9.57%	4.18%	5.39%
	2		9.47%	4.23%	5.24%
Average			**11.94%**	**8.69%**	**3.25%**

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (Jul. 9, 2013, Jan. 24, 2002, Jan. 18, 1995, and Jan. 16, 1990).

(b) Moody's Investors Service.

(c) No decisions reported for following quarter.

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.937283
R Square	0.8784994
Adjusted R Square	0.8775502
Standard Error	0.0053743
Observations	130

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.026731022	0.026731	925.4929	1.94165E-60
Residual	128	0.003697026	2.89E-05		
Total	129	0.030428048			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0724076	0.001393513	51.96047	6.69E-88	0.069650272	0.07516487	0.069650272	0.075164874
X Variable 1	-0.4591583	0.015093011	-30.4219	1.94E-60	-0.48902235	-0.42929419	-0.48902235	-0.42929419

CAPM - 2013 BOND YIELD

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	AGL Resources	2.5%	10.1%	12.6%	3.2%	9.4%	0.75	10.3%	4,944.6	0.92%	11.2%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	0.70	9.8%	3,520.1	1.14%	10.9%
3	Laclede Group	2.5%	10.1%	12.6%	3.2%	9.4%	0.60	8.8%	1,008.1	1.73%	10.6%
4	New Jersey Resources	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	1,751.3	1.72%	11.0%
5	NiSource, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	0.80	10.7%	8,612.3	0.76%	11.5%
6	Northwest Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	0.60	8.8%	1,131.3	1.73%	10.6%
7	Piedmont Natural Gas	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	2,487.4	1.70%	11.0%
8	South Jersey Industries	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	1,765.8	1.72%	11.0%
9	Southwest Gas Corp.	2.5%	10.1%	12.6%	3.2%	9.4%	0.75	10.3%	2,119.8	1.70%	12.0%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	3.2%	9.4%	0.65	9.3%	2,160.1	1.70%	11.0%
	Average							**9.6%**			**11.1%**
	Midpoint (k)							**9.8%**			**10.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jun. 21, 2013).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 15, 2013).
(c) (a) + (b).
(d) Based on data from IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013); & Moody's Investors Service at www.credittrends.com.
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 7, 2013).
(g) (d) + (e) x (f).
(h) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
(i) *Morningstar* , "2013 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2013).
(j) (g) + (h).
(k) Average of low and high values.

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)			2014-17						Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.5%	10.1%	12.6%	4.5%	8.1%	0.75	10.6%	4,944.6	0.92%	11.5%
2	Atmos Energy Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	0.70	10.2%	3,520.1	1.14%	11.3%
3	Laclede Group	2.5%	10.1%	12.6%	4.5%	8.1%	0.60	9.4%	1,008.1	1.73%	11.1%
4	New Jersey Resources	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	1,751.3	1.72%	11.5%
5	NiSource, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	0.80	11.0%	8,612.3	0.76%	11.7%
6	Northwest Natural Gas	2.5%	10.1%	12.6%	4.5%	8.1%	0.60	9.4%	1,131.3	1.73%	11.1%
7	Piedmont Natural Gas	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	2,487.4	1.70%	11.5%
8	South Jersey Industries	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	1,765.8	1.72%	11.5%
9	Southwest Gas Corp.	2.5%	10.1%	12.6%	4.5%	8.1%	0.75	10.6%	2,119.8	1.70%	12.3%
10	WGL Holdings, Inc.	2.5%	10.1%	12.6%	4.5%	8.1%	0.65	9.8%	2,160.1	1.70%	11.5%
	Average							**10.0%**			**11.5%**
	Midpoint (k)							**10.2%**			**11.7%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jun. 21, 2013).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 15, 2013).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2014-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 22, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); & Blue Chip Financial Forecasts, Vol. 32, No. 6 (Jun. 1, 2013).
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 7, 2013).
(g) (d) + (e) x (f).
(h) ($ millions) www.valueline.com (retrieved Jun. 27, 2013).
(i) *Morningstar* , "2013 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2013).
(j) (g) + (h).
(k) Average of low and high values.

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	5,937.7	0.92%	10.7%
2	Ameren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	8,665.7	0.76%	11.5%
3	Avista Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	1,724.3	1.72%	11.5%
4	Black Hills Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	2,333.5	1.70%	12.4%
5	CenterPoint Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	10,588.8	0.76%	11.5%
6	CMS Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	7,495.4	0.92%	11.1%
7	Consolidated Edison	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	17,408.1	0.76%	9.6%
8	Dominion Resources	2.5%	10.1%	12.6%	3.1%	9.5%	0.65	9.3%	34,290.9	-0.37%	8.9%
9	DTE Energy Co.	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	12,180.0	0.76%	11.0%
10	Duke Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	49,843.6	-0.37%	8.4%
11	Empire District Elec	2.5%	10.1%	12.6%	3.1%	9.5%	0.65	9.3%	1,020.5	1.73%	11.0%
12	Integrys Energy Group	2.5%	10.1%	12.6%	3.1%	9.5%	0.90	11.7%	4,908.0	0.92%	12.6%
13	MGE Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	1,382.2	1.72%	10.5%
14	Northeast Utilities	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	13,958.6	0.76%	10.5%
15	NorthWestern Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	1,587.4	1.72%	11.5%
16	OGE Energy Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	7,497.2	0.92%	11.1%
17	Pepco Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	5,048.1	0.92%	11.1%
18	PG&E Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.55	8.3%	19,794.7	-0.37%	8.0%
19	Pub Sv Enterprise Grp	2.5%	10.1%	12.6%	3.1%	9.5%	0.75	10.2%	17,250.0	0.76%	11.0%
20	SCANA Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.65	9.3%	7,276.0	0.92%	10.2%
21	Sempra Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.80	10.7%	21,193.3	-0.37%	10.3%
22	UIL Holdings	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	2,068.6	1.70%	11.5%
23	Vectren Corp.	2.5%	10.1%	12.6%	3.1%	9.5%	0.70	9.8%	2,992.4	1.14%	10.9%
24	Wisconsin Energy	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	9,931.2	0.76%	9.6%
25	Xcel Energy, Inc.	2.5%	10.1%	12.6%	3.1%	9.5%	0.60	8.8%	14,743.7	0.76%	9.6%
	Average							**9.8%**			**10.6%**
	Midpoint (g)							**10.0%**			**10.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 13, 2012).

(b) Weighted average based on growth projections from The Value Line Investment Survey (Dec. 13, 2012), www.yahoo.com (retrieved Jan. 6, 2013), and www.zacks.com (retrieved Jan. 6, 2013).

(c) Average yield on 30-year Treasury bonds for 2013 based on data from the ; ; & Based on monthly average bond yields for the six-month period Jan. 2013 - Jun. 2013 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm..

(d) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).

(e) ($ millions) www.valueline.com (retrieved July 29, 2013).

(f) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(g) Average of low and high values.

CAPM - PROJECTED BOND YIELD

COMBINATION GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Alliant Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	5,937.7	0.92%	11.0%
2	Ameren Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	8,665.7	0.76%	11.7%
3	Avista Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	1,724.3	1.72%	11.8%
4	Black Hills Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	2,333.5	1.70%	12.6%
5	CenterPoint Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	10,588.8	0.76%	11.7%
6	CMS Energy Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	7,495.4	0.92%	11.4%
7	Consolidated Edison	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	17,408.1	0.76%	10.0%
8	Dominion Resources	2.5%	10.1%	12.6%	4.2%	8.4%	0.65	9.7%	34,290.9	-0.37%	9.3%
9	DTE Energy Co.	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	12,180.0	0.76%	11.3%
10	Duke Energy Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	49,843.6	-0.37%	8.9%
11	Empire District Elec	2.5%	10.1%	12.6%	4.2%	8.4%	0.65	9.7%	1,020.5	1.73%	11.4%
12	Integrys Energy Group	2.5%	10.1%	12.6%	4.2%	8.4%	0.90	11.8%	4,908.0	0.92%	12.7%
13	MGE Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	1,382.2	1.72%	11.0%
14	Northeast Utilities	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	13,958.6	0.76%	10.8%
15	NorthWestern Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	1,587.4	1.72%	11.8%
16	OGE Energy Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	7,497.2	0.92%	11.4%
17	Pepco Holdings	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	5,048.1	0.92%	11.4%
18	PG&E Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.55	8.8%	19,794.7	-0.37%	8.5%
19	Pub Sv Enterprise Grp	2.5%	10.1%	12.6%	4.2%	8.4%	0.75	10.5%	17,250.0	0.76%	11.3%
20	SCANA Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.65	9.7%	7,276.0	0.92%	10.6%
21	Sempra Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.80	10.9%	21,193.3	-0.37%	10.6%
22	UIL Holdings	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	2,068.6	1.70%	11.8%
23	Vectren Corp.	2.5%	10.1%	12.6%	4.2%	8.4%	0.70	10.1%	2,992.4	1.14%	11.2%
24	Wisconsin Energy	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	9,931.2	0.76%	10.0%
25	Xcel Energy, Inc.	2.5%	10.1%	12.6%	4.2%	8.4%	0.60	9.2%	14,743.7	0.76%	10.0%
	Average							**10.1%**			**11.0%**
	Midpoint (g)							**10.3%**			**10.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Dec. 13, 2012).

(b) Weighted average based on growth projections from The Value Line Investment Survey (Dec. 13, 2012), www.yahoo.com (retrieved Jan. 6, 2013), and www.zacks.com (retrieved Jan. 6, 2013).

(c) Average yield on 30-year Treasury bonds for 2014-2017 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 24, 2013); IHS Global Insight, U.S. Economic Outlook at 25 (May 2013); & Energy Information Administration, Annual Energy Outlook 2013 (Apr. 15, 2013).

(d) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).

(e) ($ millions) www.valueline.com (retrieved July 29, 2013).

(f) *Morningstar* , "Ibbotson SBBI 2013 Valuation Yearbook," at Appendix C, Table C-1 (2013).

(g) Average of low and high values.

EXPECTED EARNINGS APPROACH

GAS GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	AGL Resources	6.0%	1.021493	6.1%
2	Atmos Energy Corp.	8.5%	1.041342	8.9%
3	Laclede Group	13.0%	1.013458	13.2%
4	New Jersey Resources	12.5%	1.014717	12.7%
5	NiSource, Inc.	10.0%	1.011369	10.1%
6	Northwest Natural Gas	10.5%	1.019217	10.7%
7	Piedmont Natural Gas	11.0%	1.026134	11.3%
8	South Jersey Industries	15.5%	1.040387	16.1%
9	Southwest Gas Corp.	10.5%	1.031894	10.8%
10	WGL Holdings, Inc.	10.0%	1.018556	10.2%
	Average (d)			**11.6%**
	Midpoint (e)			**12.5%**

(a) The Value Line Investment Survey (Jun. 7, 2013).
(b) Adjustment to convert year-end return to an average rate of return from Avista/301, Schedule WEA-4.
(c) (a) x (b).
(d) Excludes highlighted figures.
(e) Average of low and high values.

EXPECTED EARNINGS APPROACH

COMBINATION GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	11.0%	1.024796	11.3%
2	Ameren Corp.	8.5%	1.013071	8.6%
3	Avista Corp.	8.5%	1.02038	8.7%
4	Black Hills Corp.	9.5%	1.020606	9.7%
5	CenterPoint Energy	13.0%	1.022577	13.3%
6	CMS Energy Corp.	13.0%	1.032269	13.4%
7	Consolidated Edison	9.0%	1.016102	9.1%
8	Dominion Resources	16.0%	1.036491	16.6%
9	DTE Energy Co.	9.0%	1.031058	9.3%
10	Duke Energy Corp.	8.0%	1.010572	8.1%
11	Empire District Elec	8.5%	1.021009	8.7%
12	Integrys Energy Group	9.0%	1.027631	9.2%
13	MGE Energy	11.5%	1.025604	11.8%
14	Northeast Utilities	9.5%	1.018153	9.7%
15	NorthWestern Corp.	9.5%	1.026147	9.7%
16	OGE Energy Corp.	11.0%	1.033849	11.4%
17	Pepco Holdings	8.0%	1.020227	8.2%
18	PG&E Corp.	8.5%	1.024174	8.7%
19	Pub Sv Enterprise Grp	10.0%	1.018688	10.2%
20	SCANA Corp.	9.5%	1.044433	9.9%
21	Sempra Energy	11.0%	1.02327	11.3%
22	UIL Holdings	9.0%	1.02653	9.2%
23	Vectren Corp.	11.5%	1.027373	11.8%
24	Wisconsin Energy	14.0%	1.016168	14.2%
25	Xcel Energy, Inc.	10.0%	1.027402	10.3%
	Average (d)			**10.5%**
	Midpoint (e)			**12.3%**

(a) The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013).
(b) Adjustment to convert year-end return to an average rate of return from Avista/301, Schedule WEA-6.
(c) (a) x (b).
(d) Excludes highlighted figures.
(e) Average of low and high values.

GAS GROUP

	Company	(a) Allowed ROE
1	AGL Resources	10.17%
2	Atmos Energy Corp.	11.72%
3	Laclede Group	NA
4	New Jersey Resources	10.30%
5	NiSource, Inc.	10.72%
6	Northwest Natural Gas	9.50%
7	Piedmont Natural Gas	10.40%
8	South Jersey Industries	10.30%
9	Southwest Gas Corp.	10.12%
10	WGL Holdings, Inc.	9.65%
	Average	**10.32%**
	Midpoint (b)	**10.61%**

(a) AUS Monthly Utility Report (Jul. 2013).
(b) Average of low and high values.

COMBINATION GROUP

	Company	(a) Allowed ROE
1	Alliant Energy	10.34%
2	Ameren Corp.	9.59%
3	Black Hills Corp.	10.72%
4	CenterPoint Energy	10.05%
5	CMS Energy Corp.	10.30%
6	Consolidated Edison	9.93%
7	Dominion Resources	10.52%
8	DTE Energy Co.	10.75%
9	Duke Energy Corp.	10.46%
10	Empire District Elec	NA
11	Integrys Energy Group	10.11%
12	MGE Energy	10.30%
13	Northeast Utilities	9.38%
14	NorthWestern Corp.	10.83%
15	OGE Energy Corp.	9.98%
16	Pepco Holdings	9.85%
17	PG&E Corp.	10.40%
18	Pub Sv Enterprise Grp	10.30%
19	SCANA Corp.	10.72%
20	Sempra Energy	11.48%
21	UIL Holdings	8.75%
22	Vectren Corp.	10.43%
23	Wisconsin Energy	10.43%
24	Xcel Energy, Inc.	10.60%
	Average	**10.27%**
	Midpoint (b)	**10.12%**

(a) AUS Monthly Utility Report (Jul. 2013).
(b) Average of low and high values.

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Church & Dwight	$ 61.74	$ 1.12	1.8%
2	Coca-Cola Co.	$ 40.51	$ 1.12	2.8%
3	Colgate-Palmolive	$ 58.17	$ 1.39	2.4%
4	Gen'l Mills	$ 49.40	$ 1.52	3.1%
5	Kellogg	$ 64.76	$ 1.84	2.8%
6	Kimberly-Clark	$ 97.82	$ 3.24	3.3%
7	McCormick & Co.	$ 71.30	$ 1.42	2.0%
8	McDonald's Corp.	$ 99.32	$ 3.08	3.1%
9	PepsiCo, Inc.	$ 82.43	$ 2.28	2.8%
10	Procter & Gamble	$ 78.66	$ 2.41	3.1%
11	Wal-Mart Stores	$ 75.64	$ 1.88	2.5%
	Average			**2.7%**

(a) Average of closing prices for 30 trading days ended July 19, 2013.
(b) The Value Line Investment Survey, Summary & Index (Jul. 19, 2013).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	**V Line**	**IBES**	**Zacks**
1	Church & Dwight	10.5%	11.8%	11.4%
2	Coca-Cola Co.	8.0%	7.9%	8.1%
3	Colgate-Palmolive	10.5%	9.1%	8.6%
4	Gen'l Mills	7.5%	7.9%	7.5%
5	Kellogg	8.0%	7.7%	7.7%
6	Kimberly-Clark	9.5%	7.8%	7.9%
7	McCormick & Co.	10.0%	13.0%	13.0%
8	McDonald's Corp.	8.0%	8.5%	9.3%
9	PepsiCo, Inc.	8.5%	8.5%	8.5%
10	Procter & Gamble	8.0%	7.6%	8.4%
11	Wal-Mart Stores	9.0%	9.3%	9.2%

(a) The Value Line Investment Survey (Apr. 26, May 3, May 31, & Jun. 28, 2013).
(b) www.finance.yahoo.com (retrieved July 23, 2013).
(c) www.zacks.com (retrieved July 23, 2013).

DCF COST OF EQUITY ESTIMATES

			(a)	(a)	(a)
			Earnings Growth		
	Company	Industry Group	V Line	IBES	Zacks
1	Church & Dwight	Household Products	12.3%	13.6%	13.3%
2	Coca-Cola Co.	Beverage	10.8%	10.7%	10.8%
3	Colgate-Palmolive	Household Products	12.9%	11.5%	11.0%
4	Gen'l Mills	Food Processing	10.6%	11.0%	10.6%
5	Kellogg	Food Processing	10.8%	10.5%	10.5%
6	Kimberly-Clark	Household Products	12.8%	11.1%	11.2%
7	McCormick & Co.	Food Processing	12.0%	15.0%	15.0%
8	McDonald's Corp.	Restaurant	11.1%	11.6%	12.4%
9	PepsiCo, Inc.	Beverage	11.3%	11.2%	11.3%
10	Procter & Gamble	Household Products	11.1%	10.7%	11.4%
11	Wal-Mart Stores	Retail Store	11.5%	11.8%	11.7%
	Average (b)		**11.6%**	**11.7%**	**11.8%**
	Midpoint (c)		**11.7%**	**12.8%**	**12.8%**

(a) Sum of dividend yield (Avista/301, Schedule WEA-14, p. 1) and respective growth rate (Avista/301, Schedule WEA-14, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

WILLIAM E. AVERA
Exhibit No. 302

Return on Equity

EXHIBIT NO. 302

OTHER ROE BENCHMARKS

Q. What is the purpose of this exhibit to your testimony?

A. This exhibit presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances of Avista. These tests include applications of the traditional CAPM analysis using current and projected interest rates, a review of expected earned returns and allowed rates of return for the utility proxy groups. Finally, I present a DCF analysis for a low risk group of non-utility firms, with which Avista must compete for investors' money.

A. Capital Asset Pricing Model

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

A. My applications of the traditional CAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the ECAPM. As shown on page 1 of Exhibit No. 301, Schedule 10, applying the forward-looking CAPM approach to the firms in the Gas Group results in an average theoretical cost of equity estimate of 9.6%, or 11.1% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities. As shown on page 1 of Exhibit No. 301, Schedule 11, adjusting the 9.9% theoretical CAPM result for the Combination Group to incorporate the size adjustment results in an average indicated cost of common equity of 10.7%.

As shown on page 2 of Exhibit No. 301, Schedule 10, incorporating a forecasted Treasury bond yield for 2014-2017 implied a cost of equity of approximately 10.0% for the

Gas Group, or 11.5% after adjusting for the impact of relative size. For the Combination Group (page 2 of Exhibit No. 301, Schedule 11), projected bond yields implied a theoretical CAPM estimate of 10.2%, or 11.1% after incorporating the size adjustment.

B. Expected Earnings Approach

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

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

Q. What economic premise underlies the expected earnings approach?

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

Q. How is the comparison of opportunity costs typically implemented?

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

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

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

A. Value Line's projections imply an average rate of return on common equity for the electric utility industry of 10.3% over its 2015-2017 forecast horizon.[1] Meanwhile, for the firms in the Gas Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on page 1 of Exhibit No. 301, Schedule 12. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit No. 301, Schedule 4. As shown on page 1 of Exhibit No. 301, Schedule 12, Value Line's projections for the Gas Group suggest an average ROE of approximately 11.6%. As shown on page 2 of Exhibit No. 301, Schedule 12, Value Line's projections for the Combination Group suggested an average ROE of 10.5%.[2]

C. Allowed ROEs

Q. Can allowed ROEs also be used to evaluate the reasonableness of Avista's requested ROE?

A. Yes. Reference to allowed rates of return for other utilities provides another useful guideline that can be used to assess the extent to which Avista's requested 10.1% ROE is reasonable. As shown on page 1 of Exhibit No. 301, Schedule WEA-13, data from the July 2013 AUS Monthly Utility Report indicates that the average authorized ROE for the firms in the Gas Group is approximately 10.3%, with a midpoint of 10.6%. With respect to

[1] The Value Line Investment Survey (May 24, Jun. 21, & Aug. 2, 2013). Recall that Value Line reports return on year-end equity so the equivalent return on average equity would be higher.
[2] The midpoint values for the Gas and Electric Groups were 12.5% and 12.3%, respectively.

the group of combination utilities, as shown on page 2 of Exhibit No. 301, Schedule WEA-13, these firms are also presently authorized an average ROE of approximately 10.3%, with a midpoint of 10.1%.[3]

D. Low Risk Non-Utility DCF

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

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. 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 low-risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Group".

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

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but

[3] As reflected on page 2 of Exhibit No. 301, Schedule WEA-13, solely for the purposes of comparing allowed ROEs, I excluded Avista Corp. from the Combination Group.

with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

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

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

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[4]

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

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by

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

the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

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

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

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

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

1) pay common dividends;
2) have a Safety Rank of "1";
3) have a Financial Strength Rating of "B++" or greater;
4) have a beta of 0.60 or less; and
5) have investment grade credit ratings from S&P.

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

A. Table WEA-5 compares the Non-Utility Group with the Gas and Combination Groups across the four measures of investment risk discussed earlier:

TABLE WEA-5
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A	1	A+	0.58
Gas Utility	A-	2	B++	0.68
Combination Utility	BBB+	2	B++	0.70
Avista	BBB	2	A	0.70

As shown above, the average credit rating, Safety Rank, Financial Strength Rating, and beta for the Non-Utility Group suggest less risk than for Avista and the proxy groups of utilities. These measures incorporate a broad spectrum of risks, including financial and business position, the impact of regulation, relative size, and exposure to company specific factors, and they apply equally to regulated and unregulated firms. Indeed, the core idea of modern portfolio theory is that investors will diversify their holdings across multiple firms and industry groups, so that the risk of a stock is directly proportional to its beta, not the extent of competition or the freedom to set prices.

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

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

A. I applied the DCF model to the Non-Utility Group in exactly the same manner described earlier for the Electric Group. The results of my DCF analysis for the Non-Utility Group are presented in Exhibit WEA-15, with the sustainable, "br+sv" growth rates being developed on Exhibit No. 301, Schedule 14. As summarized in Table WEA-6, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE WEA-6
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	11.6%	11.7%
IBES	11.7%	12.8%
Zacks	11.8%	12.8%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. How can you reconcile these DCF results for the Non-Utility Group against the significantly lower estimates produced for your groups of utilities?

A. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As I documented earlier, the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, beta – are lower than the risks investors associate with Avista and the Gas and Combination Groups. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for Avista. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector, and the divergence between the DCF estimates for the groups of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result. The results of the Non-Utility Group DCF suggests that the 10.1% requested ROE for Avista's gas operations is a conservative estimate of a fair return..

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

A. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 1 of Exhibit WEA-2, and summarized in Table WEA-7, below:

TABLE WEA-7
SUMMARY OF ALTERNATIVE ROE BENCHMARKS

	Gas Group		Combination Group	
	Average	Midpoint	Average	Midpoint
CAPM - 2013 Yield				
Unadjusted	9.6%	9.8%	9.8%	10.0%
Size Adjusted	11.1%	10.6%	10.6%	10.3%
CAPM - Projected Yield				
Unadjusted	10.0%	10.2%	10.1%	10.3%
Size Adjusted	11.5%	11.7%	11.0%	10.6%
Expected Earnings	11.6%	12.5%	10.5%	12.3%
Allowed ROE	10.3%	10.6%	10.3%	10.1%
Non-Utility DCF				
Value Line	11.6%	11.7%		
IBES	11.7%	12.8%		
Zacks	11.8%	12.8%		

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

WILLIAM E. AVERA
Exhibit No. 303

Return on Equity

EXHIBIT NO. 303

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. Please describe your qualifications and experience.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. 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, 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 ("FERC"), 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 40 states.

In 1995, I was appointed by the PUCT 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 have also 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 have also 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.	3907 Red River
Financial Concepts and Applications	Austin, Texas 78751
Economic and Financial Counsel	(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 (almost 200 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 for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in almost 300 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, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Co-chair, Synchronous Interconnection Committee established by Texas Legislature to study interconnection of Texas with national grid; 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.; Appointed by Hays County

Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed 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

Treasurer, Dripping Springs Presbyterian Church; Board of Directors, 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 (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

‘‘Economic Perspectives on Texas Water Resources,” with Robert M. Avera and Felipe Chacon in *Essentials of Texas Water Resources,* Mary K. Sahs, ed. State Bar of Texas (2012).

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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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

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"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).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"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)

""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)

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"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)

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

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF STEPHEN HARPER
REPRESENTING AVISTA CORPORATION

Natural Gas Supply

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

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

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

A. Yes. I graduated from the University of Washington with a Bachelor of Science Degree in Mathematics. I joined the Company in 2008 as the Senior Manager of Natural Gas Acquisition. In 2012, I was appointed the Director of Gas Supply. Prior to joining Avista, I was a Principle with Evergreen Energy Company, LLC, a Spokane-based commodity hedge fund, from 2006 to 2008. From 1999 to 2006, I was employed as Manager of Asset Optimization with Avista Energy. From 1991 to 1999, I was Manager of Gas Supply with Puget Sound Energy (formally Washington Natural Gas Company). From 1990 to 1991, I was employed by Williams Energy Company as a Regional Marketing Representative in their Western Region. From 1981 to 1990, I held several positions with Washington Natural Gas.

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

A. The purpose of my testimony is to describe Avista's natural gas resource planning process, discuss the Company's purchase of the Klamath Falls Lateral in 2013, and provide an update on the Company's 2012 Natural Gas Integrated Resource Plan.

Q. Are you sponsoring exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit 401 which is a copy of the Company's 2012 Natural Gas Integrated Resource Plan which was acknowledged by this Commission on April

30, 2013.

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

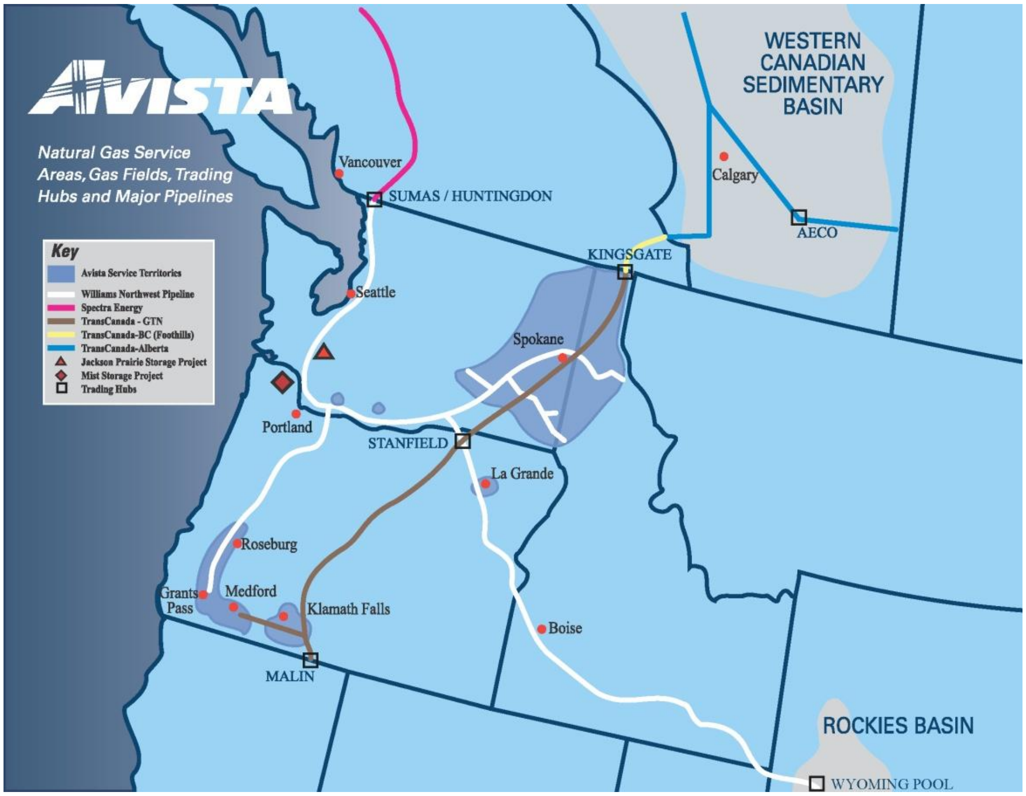
A. No, Avista is not proposing changes in this filing related to the cost of natural gas. Changes in the cost of natural gas included in customers' rates are addressed in the Company's annual PGA filing. The Company expects to make its annual PGA filing on or before August 31, 2013.

<u>Procurement Planning</u>

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

A. Avista purchases natural gas for its distribution customers in wholesale markets at multiple supply basins in the western United States and western Canada. Purchased natural gas can be transported through six connected pipelines on which Avista holds firm contractual transportation rights. These contracts provide access to both US and Canadian-sourced supply. The US-sourced gas represents 20% of the contractual rights and provides transportation from the Rocky Mountains. The remaining 80% provides access to Alberta and British Columbia supply basins. This diverse portfolio of natural gas resources allows the Company to make natural gas procurement decisions based on the reliability and economics that provide the most benefit to our customers. As natural gas prices in the Pacific Northwest can be affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada, future prices and delivery constraints may cause the source mix to vary.

Below is a map showing our service territory, natural gas trading hubs, interstate pipelines, and natural gas storage facilities:



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

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

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

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

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

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

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

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

1. **<u>Previous Year(s) Hedges</u>** – longer-term fixed-price purchases executed as a part of a previous year’s Procurement Plan.
2. **<u>Prompt Year Hedges</u>** – the portion of the portfolio addressed through the utilization of hedge windows. In each window, fixed price purchases are made for various prompt year delivery periods. Prior to the execution of each window, market conditions, fundamental market knowledge, and other information are considered to determine if execution will occur.
3. **<u>Storage Withdrawals</u>** – utilizing the capacity and deliverability from the Jackson Prairie storage facility, Avista is able to inject natural gas during the summer months and withdraw it to serve customers during the higher demand winter months. I will provide an overview of Jackson Prairie later in my testimony.
4. **<u>Discretionary Long-term Hedges</u>** – opportunistic purchases based on a set of price levels, or targets, which trigger possible execution. At the time the triggers are reached, evaluation of market conditions, fundamental market

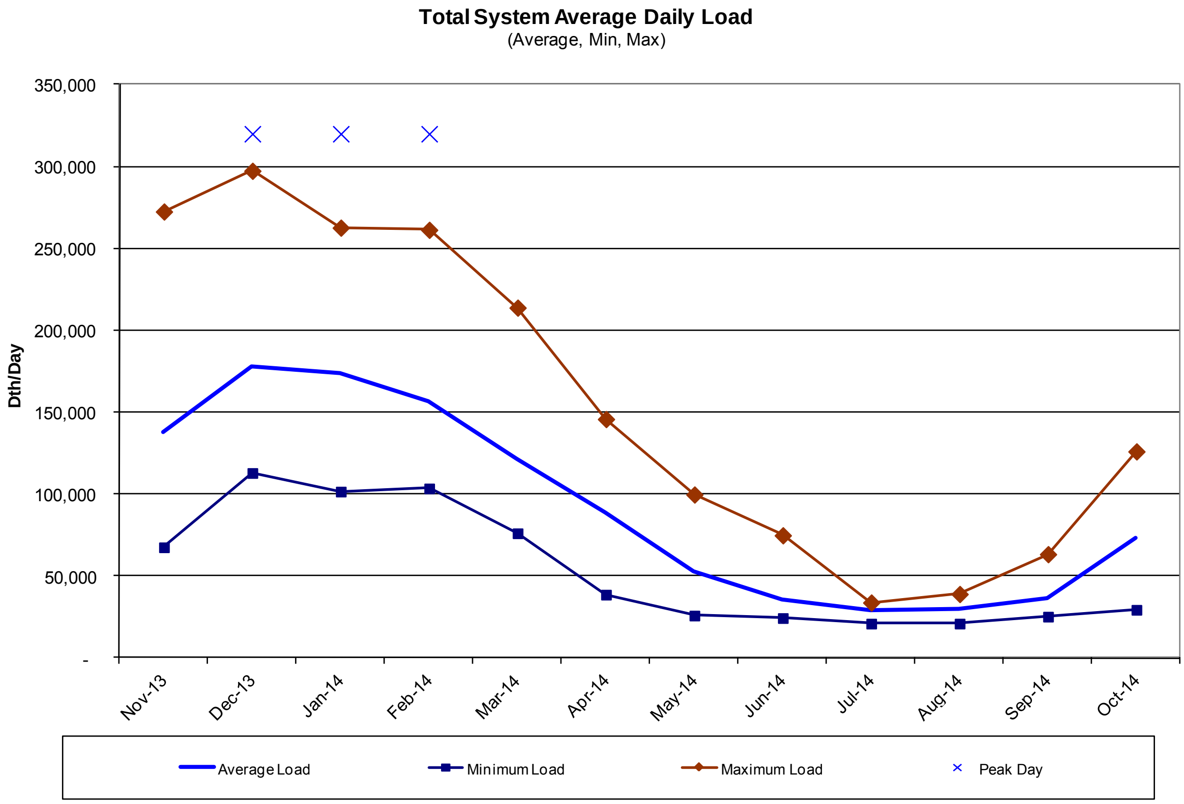
knowledge, and other information are considered. These hedges will generally be executed when they can be done at or below the established targets.

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

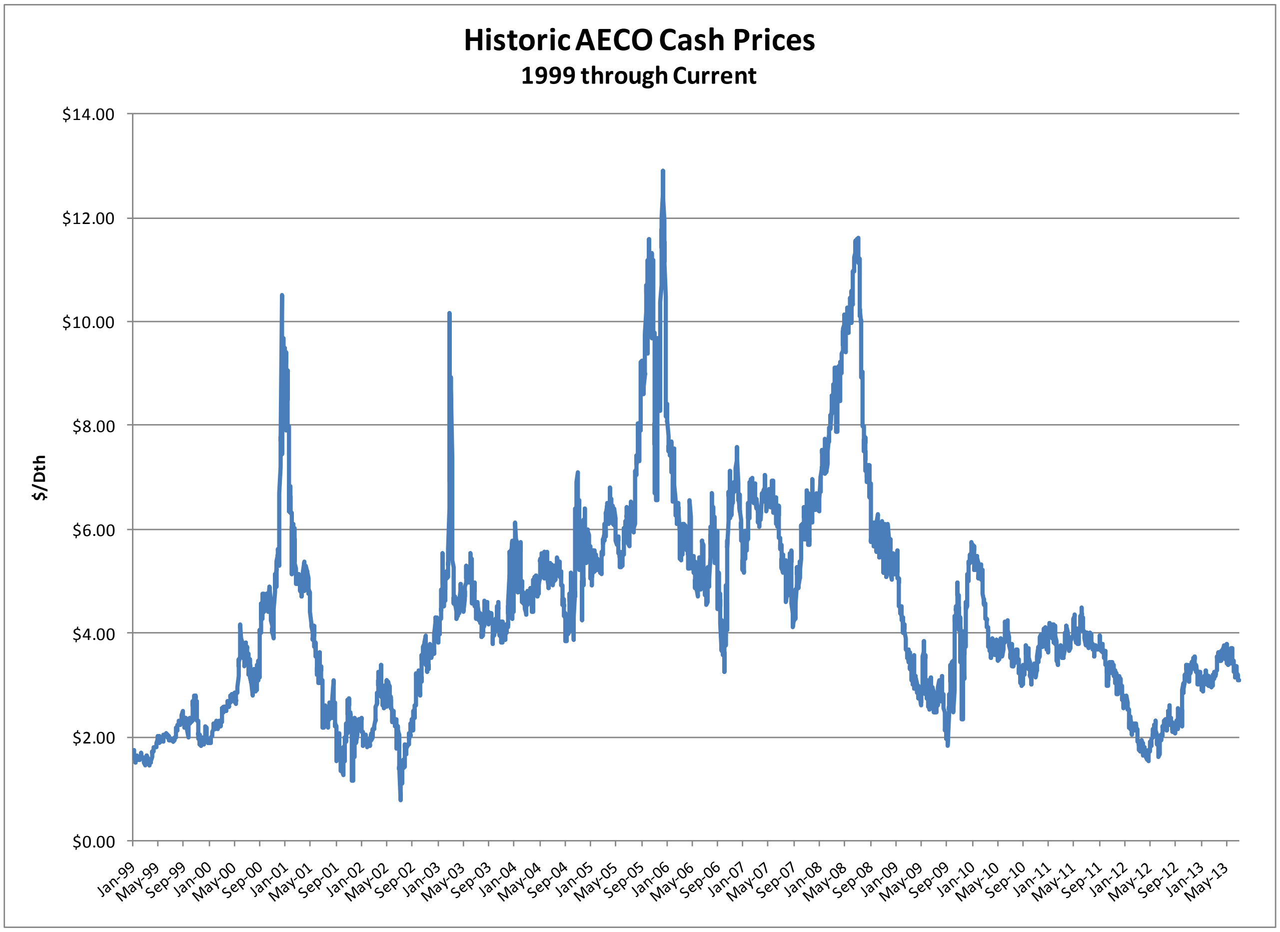
Q. Please describe how the Procurement Plan manages volatility.

A. The Procurement Plan focuses on managing demand and price volatility. Natural gas demand is volatile and will vary day to day. For example, system-wide *<u>average</u>* daily demand can fluctuate between 27,000 dekatherms (Dth) per day during a <u>summer</u> month and 180,000 Dth/day during a <u>winter</u> month. Further, December's system-wide daily demand volatility has ranged from a low of 100,000 Dth/day to a high of 300,000 Dth/Day. For year-to-date 2013, the observed system-wide peak demand was 228,162 Dth/Day. Finally, from Avista's 2012 IRP, system-wide peak day demand for 2013-2014 heating season is forecasted to be approximately 320,000 Dth per day.

In order to manage these seasonal, monthly and daily volume swings, Avista shapes the components of the Procurement Plan by month (i.e. more natural gas is hedged for the winter months than for the summer). Following is a chart that shows the demand volatility:



Price volatility can also vary widely by season, month and day. Below is a chart depicting the natural gas price volatility over time. Avista cannot predict with accuracy where natural gas prices may go, however, our experience and fundamentally based market intelligence guide our procurement decisions. By layering in fixed price purchases over time, setting upper and lower pricing levels on the hedge windows, opportunistically hedging at favorable pricing levels through the discretionary hedge program, and actively managing storage resources, Avista is able to meet our goal of providing a meaningful measure of price stability, together with competitive prices, for our customers.



Q. Could you please describe Avista's involvement with the Jackson Prairie natural gas storage facility?

A. Yes. Avista is one of the three original developers of the underground storage facility at Jackson Prairie, which is located near Chehalis, Washington. Although there have been corporate changes due to mergers, acquisitions and name changes, Avista, Puget Sound Energy (PSE) and Northwest Pipeline each hold a one-third share (equal, undivided interest) of this underground gas storage facility through a joint ownership agreement. Development of the facility began in the 1960's and the project first went into service in the early 1970's. Puget Sound Energy is the operator of the facility.

Q. What type of storage facility is Jackson Prairie?

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

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

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

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

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

Q. Relating to natural gas storage, what was agreed to in the Settlement Agreement approved by the Commission in Order No. 11-080 in Docket UG-201, the Company's last Oregon general rate case?

A. In Paragraph 10(e), the Company agreed "to work with the Parties on the necessary reports and changes to storage accounting processes and documentation to quantify all gas price stability and optimization benefits Oregon customers will receive from the additional JP Storage through the PGA process."

Q. How has the Company fulfilled this requirement?

A. The Company, per Docket UM-1286, holds Quarterly Update meetings with Commission Staff, Citizens' Utility Board and the Northwest Industrial Gas Users. In those meetings the Company provides updates on a number of issues including updates on natural gas storage. Further, monthly natural gas storage accounting records, including injections, withdrawals, balances, and the weighted average cost of gas, are included in Attachment F to the Company's Portfolio Guidelines responses submitted annually in the PGA.

Klamath Falls Lateral

Q. Would you please describe the Klamath Falls Lateral?

A. The Klamath Falls Lateral, which was owned and operated by Northwest Pipeline (NWP), is a 15 mile long, 6 inch transmission pipeline that interconnects with Gas Transmission Northwest (GTN) to transport natural gas to serve Avista's customers in Klamath Falls, OR. Prior to 2013, Avista was the only customer of NWP utilizing this lateral, contracting for 10,000 Dth/day[1].

In 2009, Avista negotiated a purchase option with NWP for the lateral. That purchase option provided Avista the option to purchase the lateral during NWP's next two FERC rate cases. The agreement called for a purchase price at the lateral's net book value on the date of closing. In exchange for the purchase option, Avista extended its existing NWP

[1] At 700 psig from GTN, this lateral has a capacity of over 14,000 Dth/day. The additional capacity will provide for future growth in the Klamath Falls geographic area, as identified in the Company's 2012 Natural Gas IRP.

transportation contracts in Oregon to 2035. On June 28, 2012, while NWP's rate case settlement was pending approval at FERC, Avista exercised the purchase option and entered into a Purchase and Sale Agreement with NWP for the Klamath Falls Lateral, effective January 1, 2013.

Q. Please provide an overview of the Agreement between NWP and Avista.

A. The Purchase and Sale Agreement called for Avista to purchase the Klamath Falls Lateral for a purchase price of $2,277,014. The closing date of this purchase was December 31, 2012.

Q. What is the incremental annual revenue requirement associated with this purchase?

A. The annual revenue requirement associated with this purchase is $450,039.

Q. What are the incremental savings that will accrue to customers resulting from this purchase?

A. The purchase of the lateral enabled Avista to reduce contract demand by approximately 10,000 Dth/day. This is saving Oregon customers annually $1,424,294 in firm demand costs. In short, by executing this agreement, the purchase, including the incremental revenue requirement of $450,039, will save customers approximately $1 million annually.

Q. What other benefits accrue to Oregon customers as a result of this purchase?

A. As I noted previously in my testimony, the purchase also gave the Company an additional 4,000 Dth/day in capacity, fulfilling the capacity needs for Klamath Falls as identified in the 2012 IRP. Page 6.19 of the Company's 2012 IRP, included in this filing as

Exhibit No. 401, shows that the Supply Side Resource selected by SENDOUT®[2] that would be the least cost solution to serve anticipated customer requirements for the Klamath Falls service area was the purchase of the Klamath Falls Lateral.

Q. Did the Company keep Commission Staff and other parties informed about the purchase of the lateral?

A. Yes, it did. Over the past several years, both through the IRP process and PGA quarterly meetings, and in particular the Company's 2012 quarterly meetings with Staff and other parties, Avista kept Staff informed as to the status of this potential purchase opportunity. In its May 2012 quarterly meeting, Staff and Avista even discussed the potential cost recovery associated with this purchase. Staff and the Company agreed that the associated costs and benefits should be included and reviewed in Avista's 2012 PGA filing. However, since the closing date of the purchase would not take place until December 31, 2012 rather than on November 1, 2012 when the 2012 PGA went into effect, the Company and Staff believed that the costs and benefits from the purchase should be reflected in customer's rates effective January 1, 2013.

Q. As a part of the Company's 2012 PGA, did the Company file to pass through the net benefits of the purchase of the lateral to Oregon customers?

A. Yes, it did. In Docket UG-228, Avista filed to decrease customer rates effective on January 1, 2013. The Commission, in Order No. 12-429, approved the Company's request on November 7, 2012.

Q. Did the Commission provide a finding of prudence as it related to the

[2] The SENDOUT® Gas Planning System from Ventyx is a linear programming model widely used to solve natural gas supply and transportation optimization questions. More information regarding SENDOUT® can be found in Exhibit No. 401.

purchase of the Klamath Falls Lateral in Order No. 12-429?

A. The Company did not request a finding of prudence at the time of the purchase. Avista and Staff believed that the cost and benefits relating to the transaction should be matched and flow through to customers upon the effective date of the agreement. As agreed to with Staff, the request for a finding of prudence related to this transaction would be made in the Company's next general rate case (i.e., this general rate case).

Q. Although Staff did not make a formal prudence finding, do you believe Staff was supportive of the transaction?

A. Yes, I do. As noted in Appendix A to Order No. 12-429, Commission Staff stated:

> Staff carefully reviewed Avista's work papers related to both the purchase of the Lateral and to the benefit/cost analysis performed to assess the purchase's impact on customer rates. Avista's purchase of the Lateral reduces annual costs to customers by approximately $1 million. Also, the Lateral purchase provides a cost-effective and reliable means for Avista to serve growing demand in the area of its system around the Klamath Falls Lateral.

2012 Natural Gas Integrated Resource Plan

Q. Can you please provide an overview of the Company's development of its 2012 Natural Gas Integrated Resource Plan?

A. Yes, I can. On August 31, 2012, Avista filed with the Commission its Natural Gas Integrated Resource Plan ("IRP"). The IRP forecasts natural gas demand and any supply-side and demand-side resources projected for the coming 20 years, which will help Avista continue to reliably provide natural gas to our customers. A copy of the Company's 2012 Natural Gas Integrated Resource Plan is included as Exhibit No. 401.

Q. What were the summary highlights from the 2012 IRP?

A. The 2012 Plan highlights the following:

- The Company forecasted sufficient natural gas resources well into the future with resource needs not occurring until 2028 in Oregon and 2030 in Washington and Idaho;

- The major change from the 2009 IRP was that customer growth had slowed and it was not anticipated to rebound in the near term and use per customer had declined;

- The price of natural gas had dropped significantly since our last IRP. Robust North American supplies lead by shale gas developments coupled with lackluster demand due to the economy had pushed prices down to levels not seen in the last decade; and

- As forecasted demand is relatively flat, the Company will monitor actual demand for signs of increased growth which could accelerate resource needs.

Q. Has the Company's 2012 IRP been acknowledged by the Commission?

A. Yes, the Company's IRP was acknowledged by the Commission on April 30, 2013.

Q. When will the Company file its next IRP?

A. The Company will file its next IRP on or before August 31, 2014. A courtesy work plan will be filed August 31, 2013 detailing Avista's IRP planning process as well as tentative dates and content for meetings with the Technical Advisory Group, which includes Commission Staff. Technical Advisory Group meetings will begin in the first quarter of 2014.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

AVISTA CORPORATION

STEPHEN HARPER
Exhibit No. 401

Natural Gas Integrated Resource Plan

Natural Gas Integrated Resource Plan (IRP)

Compact Disc Exhibit

Also Available At:

http://www.avistautilities.com/inside/resources/irp/pages/default.aspx

2012 NATURAL GAS INTEGRATED RESOURCE PLAN

AUGUST 31, 2012

www.avistautilities.com

AVISTA

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Note: Appendices provided under separate cover.

II SAFE HARBOR STATEMENT

This document contains forward-looking statements, including statements regarding our current expectations for future financial performance and cash flows, capital expenditures, financing plans, our current plans or objectives for future operations and other factors, which may affect the company in the future. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond our control and many of which could have significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

For a further discussion of these factors and other important factors please refer to the Company's reports filed with the Securities and Exchange Commission, which are available on our website at www.avistacorp.com. The forward-looking statements contained in this document speak only as of the date hereof. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on our business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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2012 IRP KEY MESSAGES

- Avista has a diversified portfolio of existing natural gas supply resources including owned and contracted storage, firm capacity rights on six pipelines and purchase contracts from several different supply basins. Our philosophy is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost.
- Avista's 2012 Integrated Resource Plan (IRP) forecasts lower demand for all service territories than our previous plans. These reductions are driven by lower growth rates and declining use-per-customer in our service territories than originally anticipated driven primarily by the recession.
- Additional resource needs do not occur until well into the future. In Oregon, the first resource deficits occur in 2029 and in Washington and Idaho in 2030. Demand growth averages 1.3 percent per year in the respective jurisdictions. Customer accounts are expected to grow at an annual average rate of 1.6 percent and 1.7 percent, respectively. Our plan indicates incremental pipeline transportation capacity is the preferred resource to meet the identified needs.
- An important risk with the identified future resource deficits is the relatively flat slope of forecasted demand growth. Implied in this outlook is existing resources will be sufficient to meet demand for most of the 20 year planning horizon. However, should demand growth accelerate, the steepening of the demand curve could quickly accelerate resource shortages by several years.
- Other risks evaluated include long term natural gas pricing levels, potential impacts of carbon legislation and hydraulic fracturing, future availability of existing regional resources, implication of exporting LNG, alternate weather planning standard, and potential NGV/CNG demand.
- Conservation potential is an integral component of our IRP process and a starting point for the DSM business planning process, as these programs result in multiple benefits including reduced customers' bills, reduced supply-side resource needs and reduced greenhouse gas (GHG) emissions. Lower avoided costs have challenged the cost-effectiveness of natural gas DSM programs, resulting in filings to suspend programs in Washington and Idaho. The Oregon DSM portfolio is currently under evaluation.
- The IRP identifies and establishes an Action Plan that continues to guide us toward the risk-adjusted, least-cost method of providing service to our natural gas customers. Included in this Action Plan are efforts to closely monitor avoided costs and the cost effectiveness of natural gas DSM, evaluate current price elasticity adjustment, watch LNG export trends, and perform gate station analysis.

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II INDEX OF FIGURES

II INDEX OF FIGURES (CONTINUED)

II INDEX OF FIGURES (CONTINUED)

CHAPTER 1 ‖ EXECUTIVE SUMMARY

Avista's 2012 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio that meets future customer demand requirements over the next 20 years. While the primary focus of the IRP is ensuring our ability to meet customer's needs under peak weather conditions, this process also provides a methodology for evaluating customer needs under normal or average conditions. The formal exercise of bringing together customer demand forecasts with comprehensive analyses of resource options, including supply-side resources and demand-side measures, is valuable to Avista, its customers, Regulatory Commissions and other stakeholders for long-range planning.

IRP PROCESS AND STAKEHOLDER INVOLVEMENT

The IRP is a coordinated effort by several Avista departments along with input from our Technical Advisory Committee (TAC), which includes Commission Staff, peer utilities, customers and other stakeholders. This group is a vital component of our IRP process, as it provides a forum for the exchange of ideas from multiple perspectives, identifies issues and risks and improves analytical methods. Topics discussed with the TAC include natural gas demand forecasts, demand-side management (DSM), supply-side resources, computer modeling tools and distribution planning. The end result is an integrated resource portfolio designed to serve our customers' natural gas needs well into the future while balancing cost and risk.

PLANNING ENVIRONMENT

Uncertainty is a factor in any forecast, and while there are many uncertainties to consider in this IRP there is one element that has become clear. Shale gas has changed the landscape for North American supply and turned the price of natural gas on its head. While shale is not new, the technological improvements for extraction, the value of natural gas liquids and the amount of gas associated with oil extraction have significantly impacted the volume and cost of the supply mix. Couple this with declining use-per-customer and stagnant customer growth due to the prolonged effect of the recession and you have a supply glut driving prices to lows not seen in the last decade. Even though we are hopeful that low-cost natural gas will be available for many years to come, there are no guarantees, so we continue to challenge key assumptions and perform our "what if" analysis in order to cover a broad range of possibilities.

DEMAND FORECASTS

In this IRP, we define eight distinct demand areas, which are structured around the pipeline transportation and storage resources that serve them. Our demand areas are aggregated into four large service territories (Washington/Idaho; Medford/Roseburg, Oregon; Klamath Falls, Oregon and La Grande, Oregon) and then disaggregated by the pipelines that serve them. The Washington/Idaho service territory is disaggregated into areas that can be served only by Northwest Pipeline (NWP), only by Gas Transmission Northwest (GTN) and by both pipelines. The Medford service territory is also disaggregated into an area that can only be served by NWP and GTN.

Avista's approach to demand forecasting focuses on customer growth and use-per-customer as the base components of demand. We recognize and have accounted for weather as the most significant direct demand-influencing factor. We also study other factors that influence demand, including population, employment trends, age and income demographics, construction trends, conservation technology, new uses development (e.g. natural gas vehicles) and use-per-customer trends.

Recognizing that customers adjust consumption in response to price, we also analyzed factors that could influence natural gas prices and demand through price elasticity. These included:

- Supply Trends – Shale gas, Canadian supply availability, and export LNG
- Infrastructure Trends – regional pipeline projects, national pipeline projects, and storage
- Regulatory Trends – subsidies, market transparency/speculation, and carbon legislation
- Other Trends – thermal generation, and energy correlations (i.e. oil/gas, coal/gas, liquids/gas)

We developed a historical-based reference case and conducted sensitivity analysis on key demand drivers by varying assumptions to understand how demand changes. Using this information and incorporating input from the TAC, we formed several alternate demand scenarios for detailed analysis. Table 1.1 summarizes these scenarios, which do not represent the maximum bounds of possible cases, but frame a range of potential outcomes. Within this range, we define an Average Case, which represents our demand forecast for normal planning purposes. Then we define an Expected Case, which we view as the most likely scenario for peak day planning purposes.

Table 1.1 **Demand Scenarios**
Average Case
Expected Case
High Growth, Low Price
Low Growth, High Price
Alternate Weather Standard

The IRP process defines the methodology and is the basis for the development of two primary types of demand forecasts – annual average daily and peak day. First is an evaluation of annual average daily demand forecasts which are useful for preparing revenue budgets, developing natural gas procurement plans and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for new resource acquisitions to meet our customers' natural gas needs in extreme weather conditions. The demand forecasts from the Average and Expected Cases revealed the following:

ANNUAL AVERAGE DAILY DEMAND – Average day, system-wide core demand is projected to increase from an average of 96,160 dekatherms per day (Dth/day) in 2012 to 117,660 Dth/day in 2031. This is an annual average growth rate of 1.1 percent and is net of projected conservation savings from DSM programs.[1]

PEAK DAY DEMAND – Coincidental peak day, system-wide core demand is projected to increase from a peak of 365,720 Dth/day in 2013 to 474,670 Dth/day in 2031. Forecasted non-coincidental peak day demand peaks at 341,850 Dth/day in 2012 and increases to

[1] Appendix 3.9 shows gross demand, DSM savings and net demand.

440,630 Dth/day in 2031, a 1.3 percent compounded growth rate in peak day requirements. This is also net of projected conservation savings from DSM programs.

Figure 1.1 shows forecasted **average daily demand** for the five main demand scenarios modeled over the planning horizon.

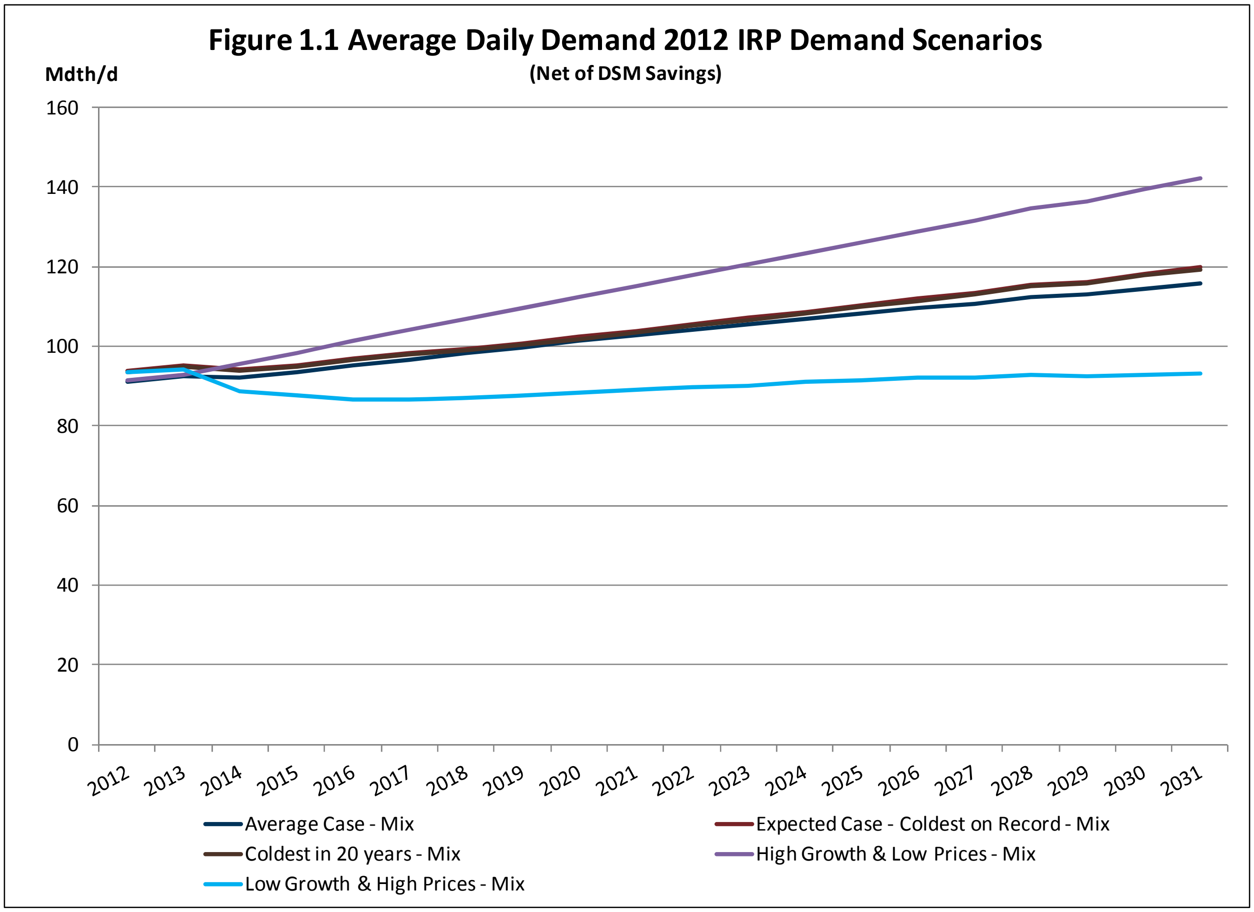
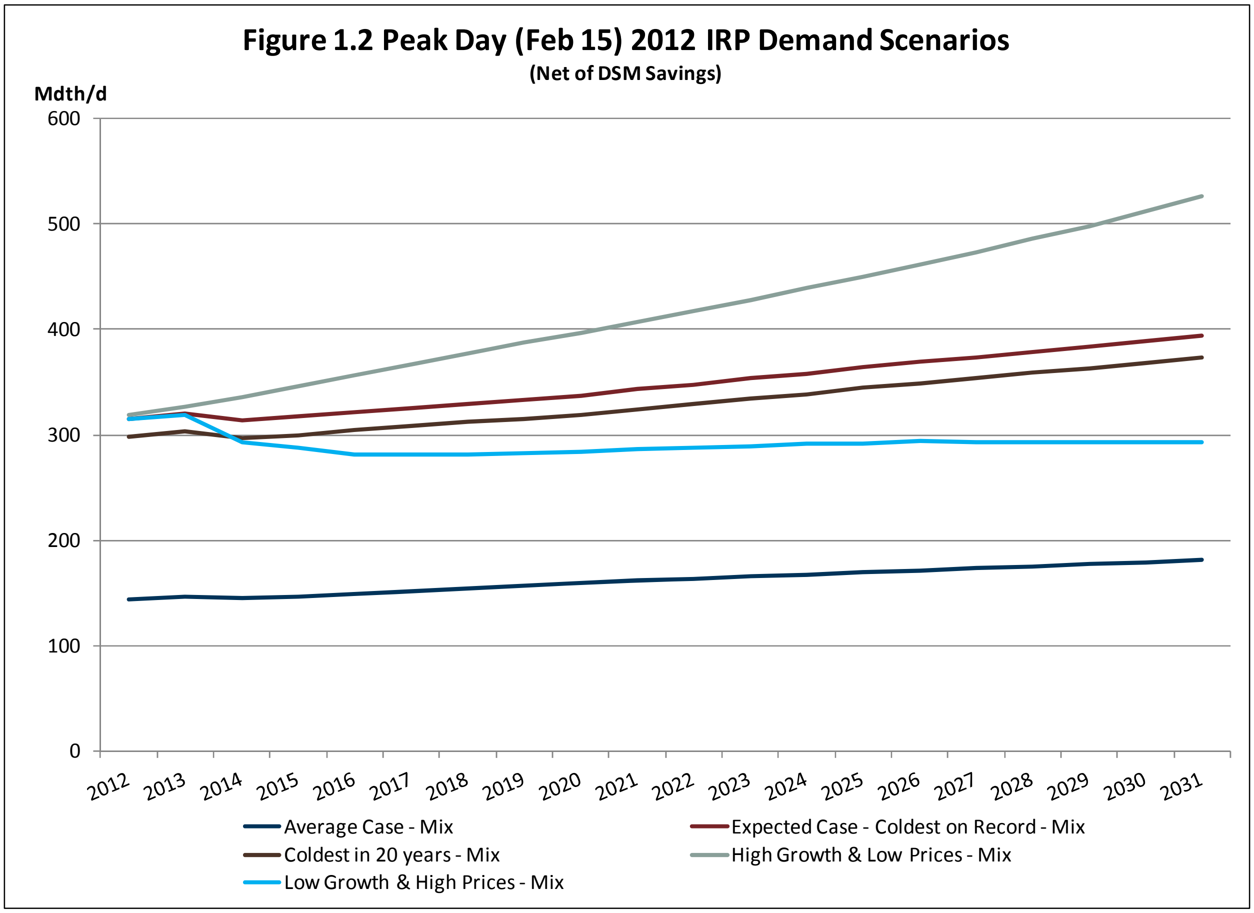


Figure 1.2 shows forecasted system-wide **peak day demand** for the five main demand scenarios modeled over the planning horizon.

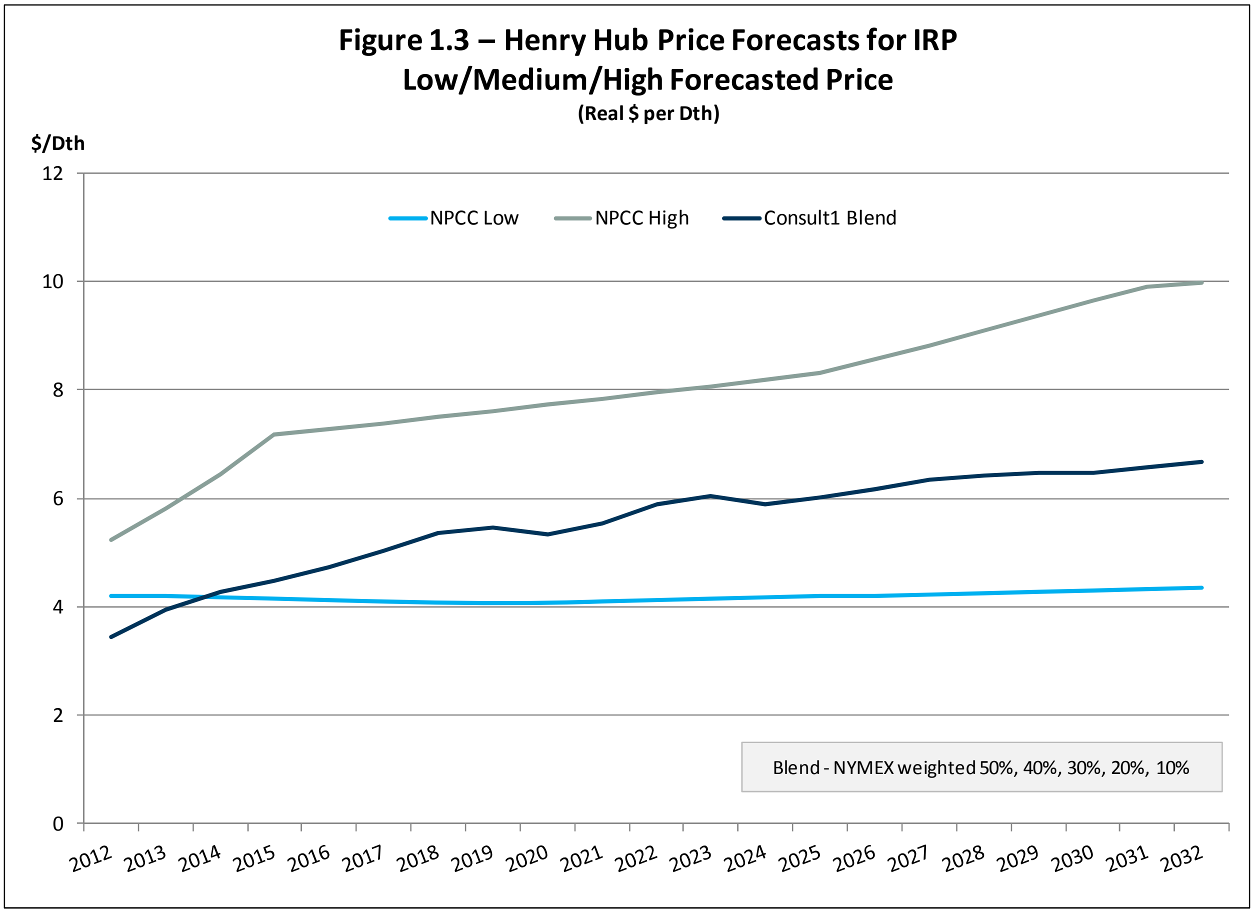


NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of integrated resource planning because the commodity price is a significant component of the total cost of a resource option. This affects the avoided cost threshold for determining cost-effectiveness of conservation measures. The price of natural gas also influences the consumption of natural gas by customers. A price elasticity adjustment to use per customer is modeled to reflect customer response to changing natural gas prices.

At the end of our last planning cycle the impacts of shale gas on market prices were just beginning to be realized. Forecasters anticipated that this resource could have a significant impact on lowering prices over the long term. However, a faster recovery of customer growth, aggressive carbon legislation in the near term, and sizeable coal switching creating significant gas-fired demand were also anticipated. These factors produced price forecasts, while lower than previous forecasts, higher than current trends. Now more information is known about the costs and volumes produced by shale gas and there appears to be consensus that production costs will continue to stay low for quite some time.

Although we do not believe we can accurately predict future prices for the 20-year horizon of this IRP, we have reviewed several price forecasts from credible sources and have selected high, medium and low price forecasts to represent a reasonable range of pricing possibilities for our analysis. The range of prices provides necessary variation for addressing uncertainty of future prices. Figure 1.3 depicts the price forecasts used in our IRP.



Long run statistical analysis shows a consumption response to changes in price. In order to model a consumption response to these price curves, we utilized an expected elasticity response factor, which was applied under various scenarios. We will monitor this assumption over the IRP cycle and make any necessary adjustments.

EXISTING AND POTENTIAL RESOURCES

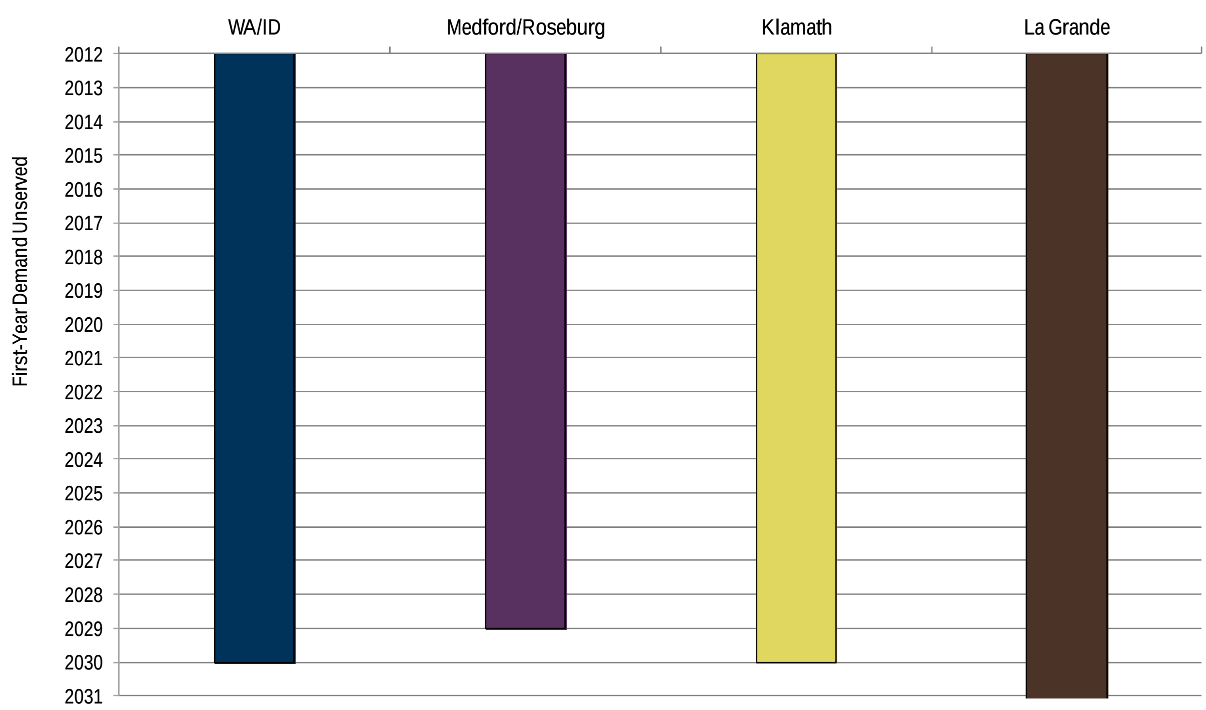
Avista has a diversified portfolio of natural gas supply resources, including contracts to purchase natural gas from several supply basins; owned and contracted storage providing flexibility of supply sources; and firm capacity rights on six pipelines diversifies delivery of supply to our service territory city gates. For potential resource additions, we also consider incremental pipeline transportation, storage options, distribution enhancements and various forms of liquefied natural gas storage or service.

In our IRP process, we model aggregated conservation potential that reduce demand if they are cost-effective over the planning horizon. Based on the projected natural gas prices and the estimated cost of alternative supply resources, our computer planning model (SENDOUT®) selects conservation savings for further review and implementation. Utilizing IRP selected savings as a starting point the operational business planning process ultimately determines the DSM programs cost-effectiveness. Given current avoided costs, programs in Washington and Idaho have proven to be cost ineffective and filings were made to suspend programs in Washington and Idaho. In Oregon we are able to offer limited programs on a cost-effective basis. We actively promote these measures to our customers as one component of a comprehensive strategy to arrive at mix of best cost/risk adjusted resources.

RESOURCE NEEDS

In our Average Case demand scenario matched with our existing supply resources scenario, we determined we are not resource deficient in the 20 year planning horizon. Using our Expected Case demand scenario, matched with our existing resources supply scenario, we assessed when the first year peak day demand is not fully served. The results of this portfolio are summarized in Figure 1.4.

Figure 1.4 - First-Year Peak Demand Not Met with Existing Resources Expected Case



In Washington and Idaho, this system first becomes unserved in 2030 in the Expected Case. In Oregon, the first unserved year is in Medford/Roseburg in 2029 and 2030 in Klamath Falls. The La Grande system does not go unserved at any time during the 20-year planning horizon.

Figures 1.5 through 1.8 illustrate when our peak day demand first goes unserved by service territory for both this IRP and our prior IRP. These charts compare existing peak day resources to expected peak day demand by year and show timing and extent of resource deficiencies for the Expected Case. Given this information, it appears we have ample time to carefully monitor, plan and take action on potential resource additions.

Figure 1.5 - Expected Case - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15

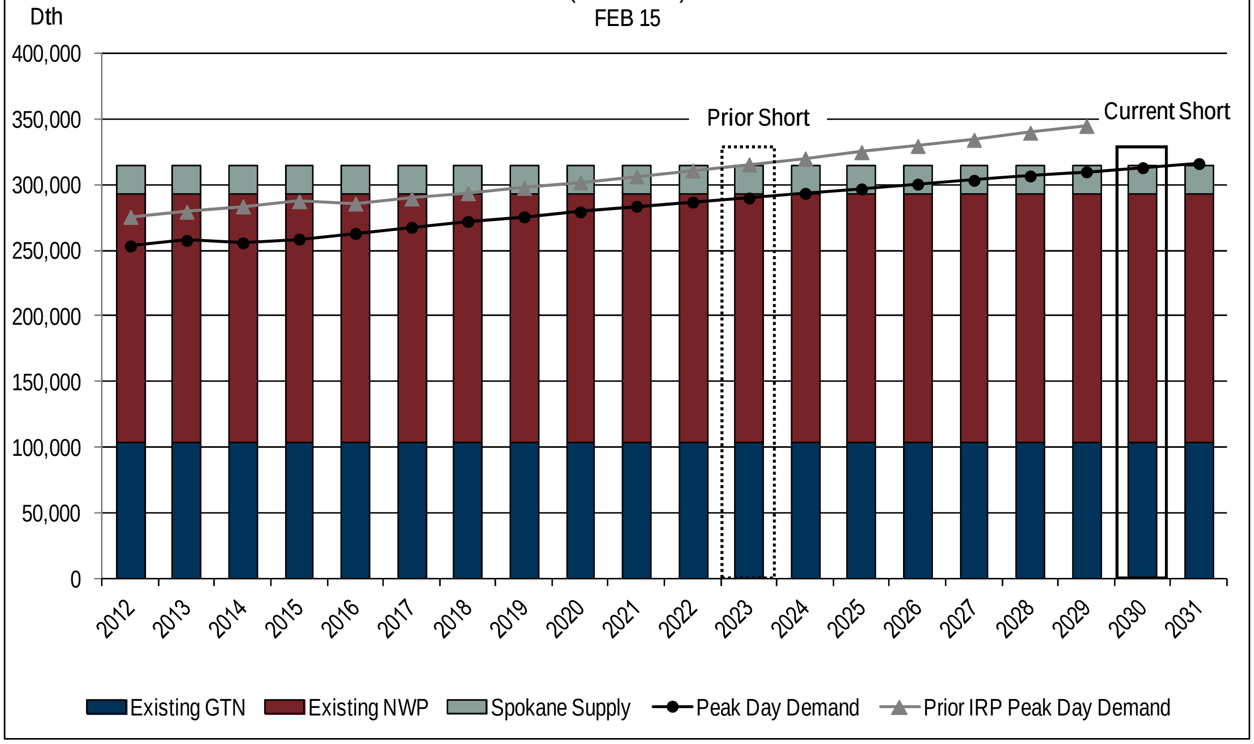
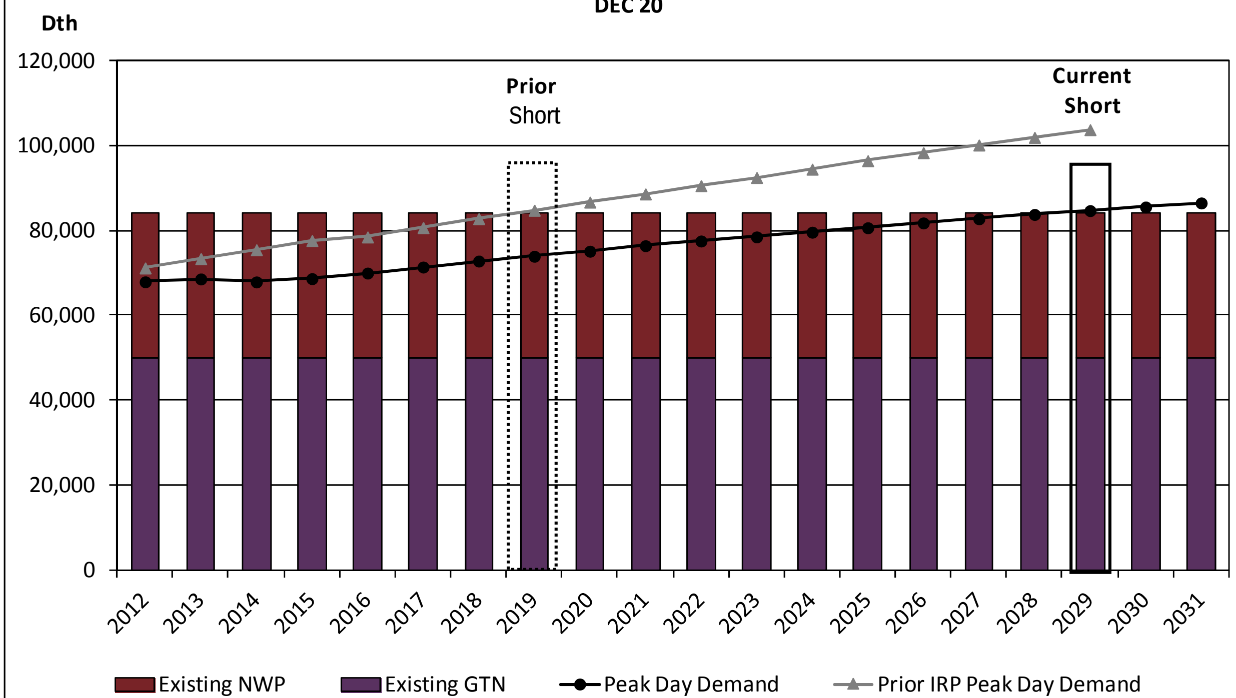


Figure 1.6 - Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20



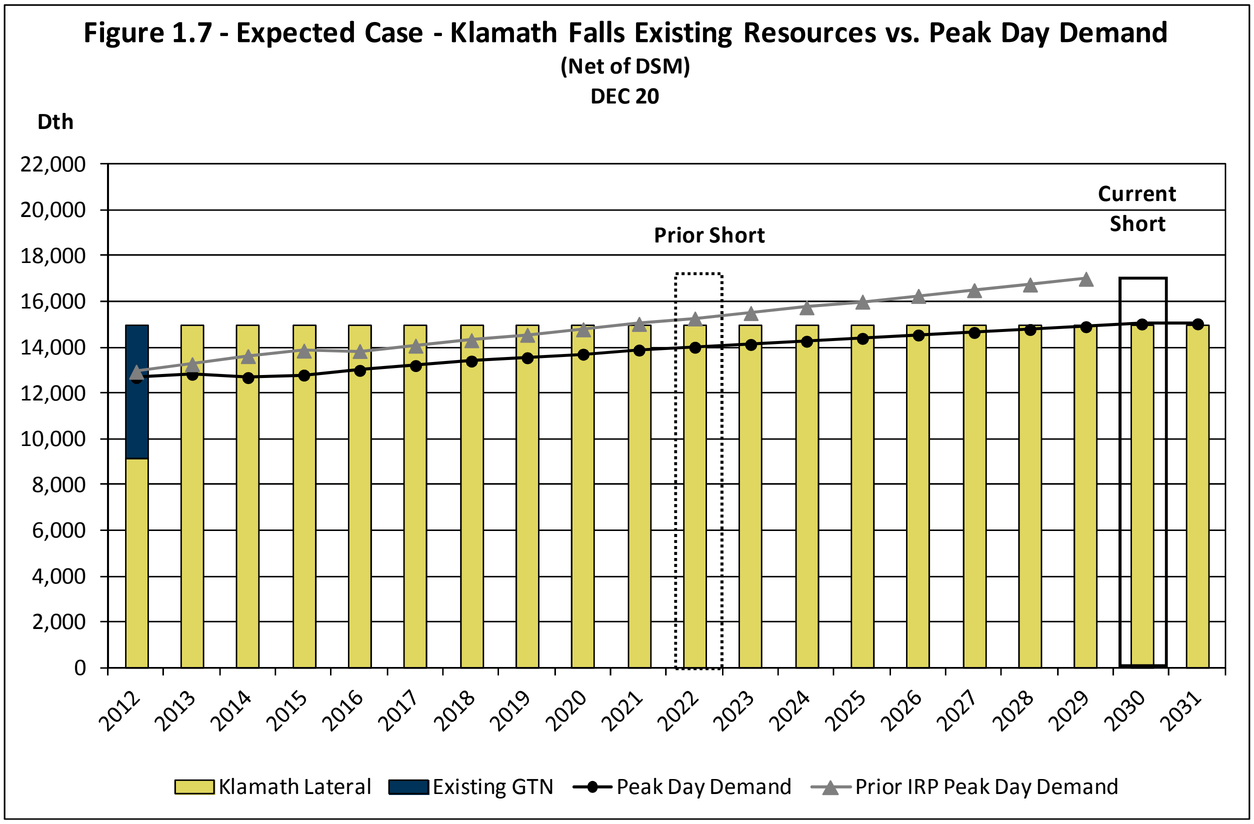


Figure 1.7 - Expected Case - Klamath Falls Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
22,000
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Prior Short
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Klamath Lateral
Existing GTN
Peak Day Demand
Prior IRP Peak Day Demand

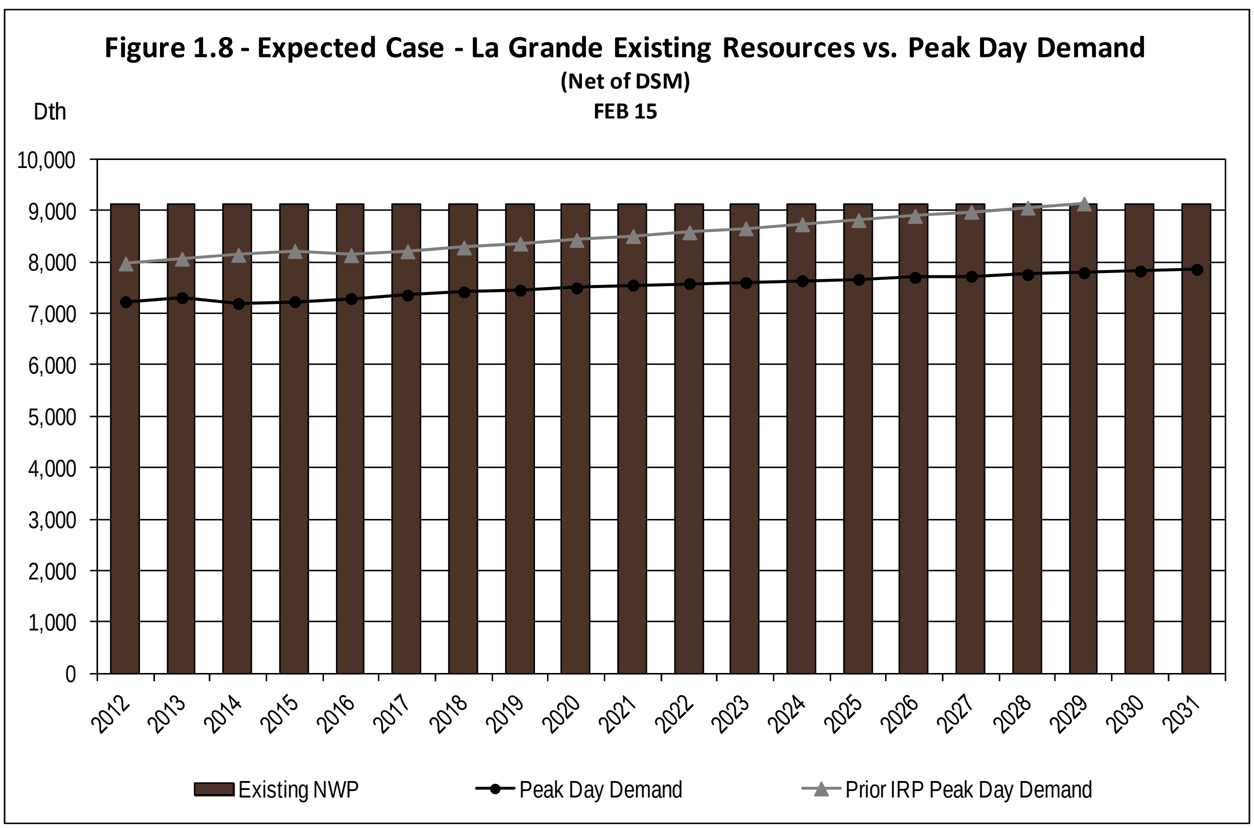
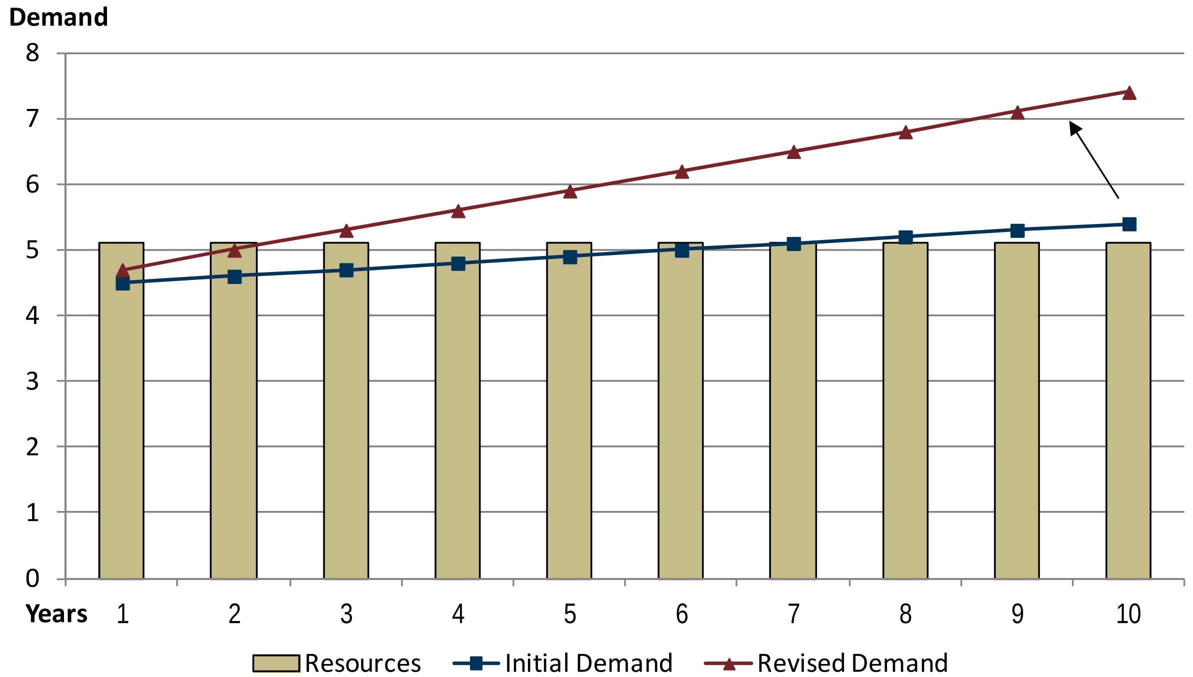


Figure 1.8 - Expected Case - La Grande Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Peak Day Demand
Prior IRP Peak Day Demand

A critical risk with respect to our identified resource shortages is the slope of forecasted demand growth, which is almost flat. This outlook implies that existing resources will be sufficient for quite some time to meet demand. However, if demand growth accelerates, the steeper demand curve could quickly accelerate resource shortages by several years. Figure 1.9 conceptually illustrates this risk. In this hypothetical example, a resource shortage does not occur until year eight in the initial demand case. However, the shortage dramatically accelerates by five years under the revised demand case to year three. This "flat demand risk" necessitates close monitoring of accelerating demand as well as careful evaluation of lead times to acquire the preferred incremental resource.

Figure 1.9 Flat Demand Risk Example



RESOURCE SELECTIONS

The next step is to determine how to resolve resource deficiencies. For this step, we identified possible resource options, placed them into the SENDOUT® model and allowed it to select the best cost/risk incremental resources over the 20-year planning horizon. Figures 1.10 through 1.12 depict the best cost/risk portfolio selected by SENDOUT® to meet the identified resource shortages. As previously mentioned, the La Grande service territory does not have resource shortages over our planning horizon in the Expected Case.

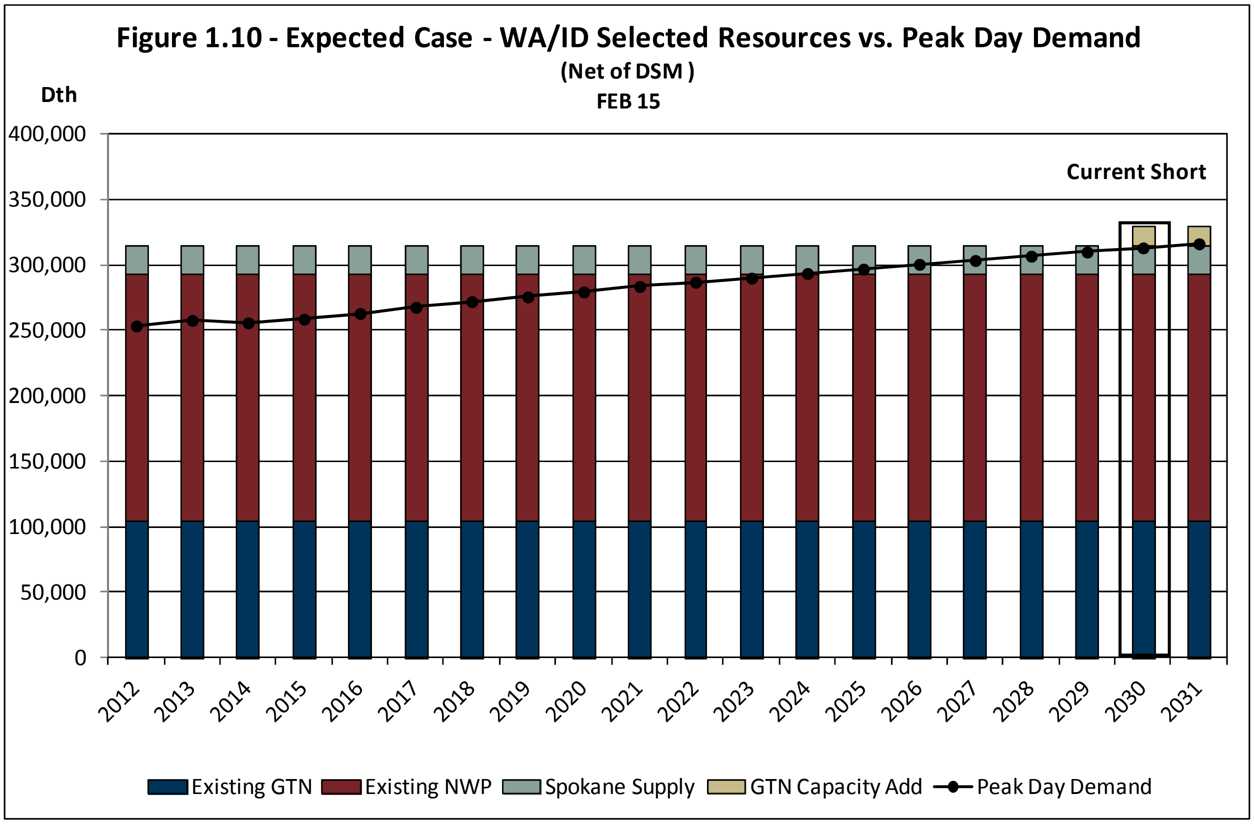


Figure 1.10 - Expected Case - WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP
Spokane Supply
GTN Capacity Add
Peak Day Demand

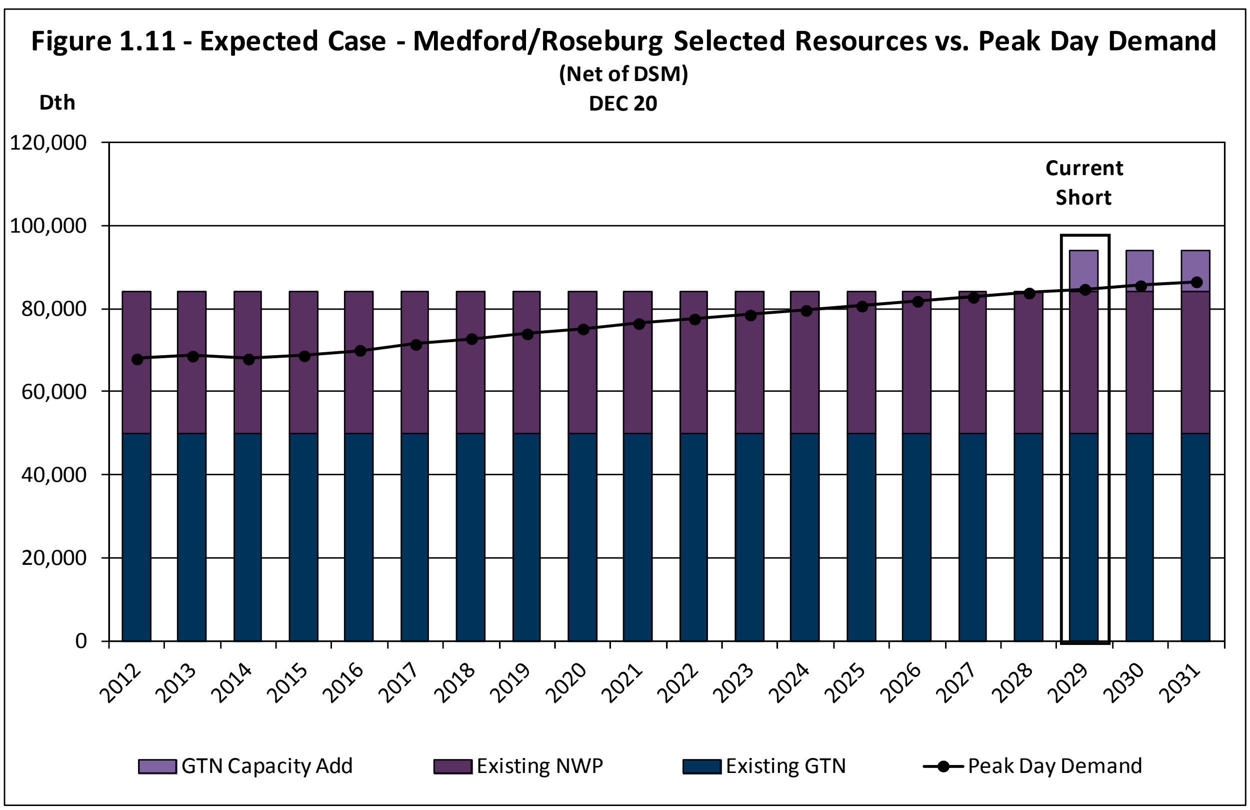
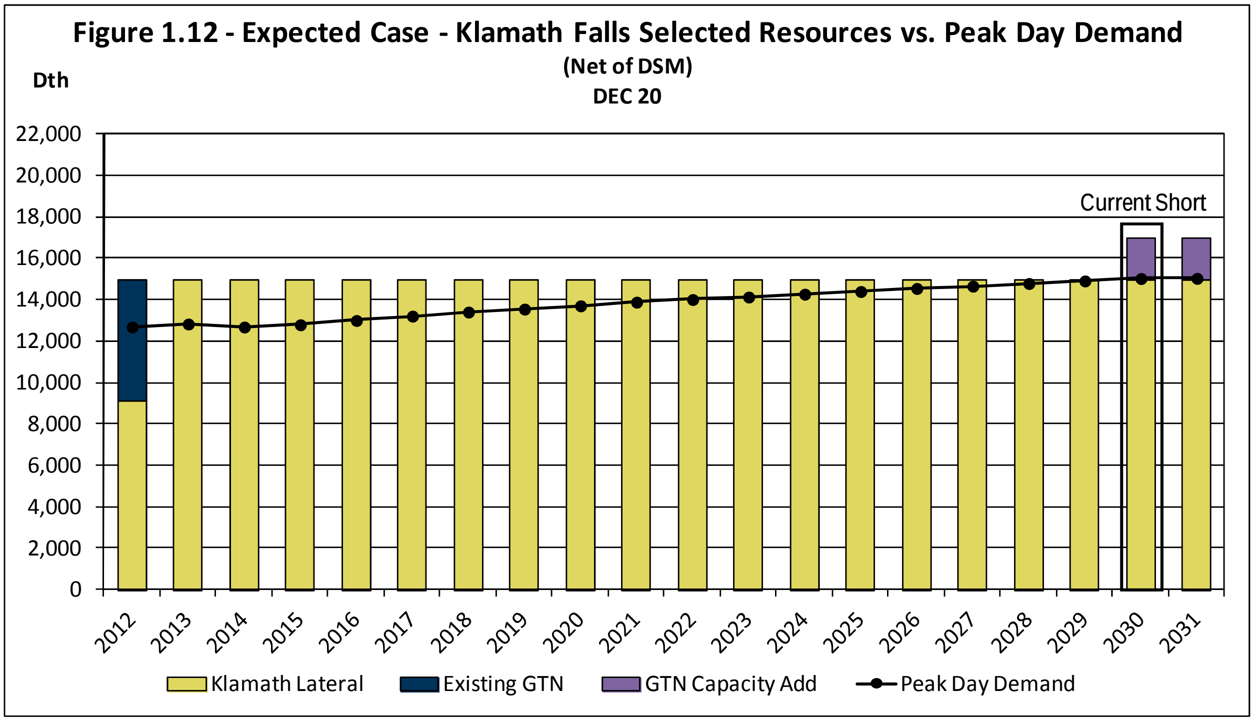


Figure 1.11 - Expected Case - Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Current
Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
GTN Capacity Add
Existing NWP
Existing GTN
Peak Day Demand

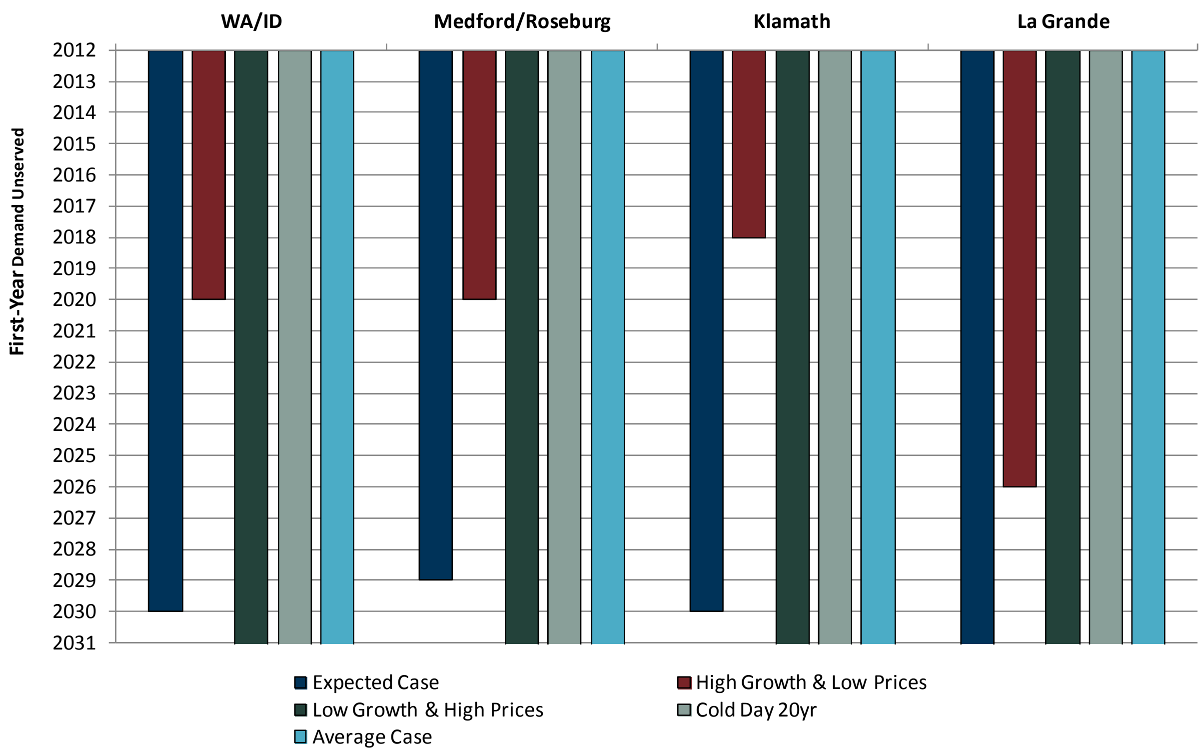


As indicated in the figures, after DSM savings, the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve resource shortages.

ALTERNATE DEMAND SCENARIOS

We performed the same SENDOUT® process for three other demand scenarios, which identified first year unserved dates for each scenario by service territory (Figure 1.13). As expected, the High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dated. This “steeper” demand lessens the “flat demand risk” discussed above, but the earlier unserved dates warrant close monitoring of demand trends and resource lead times.

Figure 1.13 - First Year Peak Demand Not Met with Existing Resources
Scenario Comparisons



II ISSUES AND CHALLENGES

Although we are satisfied with the planning, analysis and conclusions reached in this IRP, we recognize wide spread uncertainty exists requiring diligent monitoring of the following issues and challenges:

CONTINUED ECONOMIC UNCERTAINTY

Whether it is through plummeting home prices, empty retail spaces, unemployment, or lack of consumer spending, evidence of the struggling economy was seen and felt throughout our service territory and region. Growth across our service territory has been paltry at best and use-per-customer has continued to decrease. As the country continues to work through the repercussions of the recession, low to moderate growth is anticipated in our region for many years to come.

With uncertainty about the timing and magnitude of economic recovery, it is prudent to evaluate alternative growth scenarios. We sought to capture the variability of recovery through a wide range of scenarios in our modeling and analysis. Monitoring will be required to see how events unfold and if there are outcomes we did not consider, requiring adjustment of our analysis and Action Plan.

FIVE DOLLAR GAS FOREVER?

The reality of shale gas has changed the face of North American supply. The abundance of shale along with lagging demand has created a near term supply glut driving prices to lows not seen in the last decade. Shale production over the last few years has grown to 25% of total North American production. The unexpected amounts of gas extracted from shale wells, drilling induced by held-by-production (HBP) clauses in leases, increasing drilling efficiencies, and the tie in of previously drilled wells caused a significant increase in production. The excess production was able to be absorbed by the market due to a couple of colder than normal winters and hotter than normal summers. This year's warmer than normal winter highlighted the oversupply sending prices into a freefall. Forecasters anticipate prices to rebound from current lows; with forecasted prices averaging $5.50 per dekatherm at Henry Hub over the planning horizon.

For our customers we hope that the forecaster's expectations come to fruition, but we are mindful of past experiences and understand that markets can change quickly and dramatically. To address this uncertainty, our plan includes high and low price scenarios along with stochastic price analysis to capture a range of possible pricing outcomes.

EXPORTING LNG

A few short years ago importing LNG was the answer to meet North America's growing gas demand needs. Enter shale gas. Now the availability of plentiful amounts of natural gas in North America has changed LNG dynamics. Import LNG facilities are now switching gears and looking to export low cost North American gas to the higher priced Asian and European markets. One export terminal has been approved on the coast of British Columbia and another in the Gulf of Mexico. Many more applications to export are sitting at FERC for review and the same is true in Canada. In the Northwest, there are two proposed terminals in Oregon. How many of these terminals actually get approval is yet to be determined. However, exporting has the potential to alter the price and flows of natural gas across all regions in North America .

NATURAL GAS VEHICLES (NGV)

High oil prices have heightened the desire to reduce reliance on foreign oil. Aided by efforts to reduce emissions and the low cost of natural gas interest in natural gas vehicles has once again been rekindled. The transportation sector is the nation's largest consumer of foreign oil therefore changing the nation's vehicle fleet will be essential in achieving this goal.

Historically, NGV market penetration of a meaningful size has been challenging due to the lack of infrastructure and prices higher than competing alternatives. Now, lower anticipated long term natural gas prices have improved the economics and investments are being made to build out the infrastructure. Most forecasters believe the largest market will be long haul trucking followed by repetitive route fleets (e.g. public transportation, school busses, and refuse trucks) and that widespread adoption/conversion will not be immediate.

Analysis and evaluation of Avista's role in the NGV initiative is underway. Future IRP's will contain the results of this analysis and include our assessment of the potential demand and our level of participation in this market segment. For this IRP we have included in our High Growth scenario additional demand from the NGV market.

II ACTION PLAN

Our 2013-2014 Action Plan outlines activities identified by our IRP team, with advice from management and TAC members, for development and inclusion in this IRP. The purpose of these action items is to position Avista to provide the best cost/risk resource portfolio and to support and improve IRP planning. The Action Plan identifies needed supply and demand side resources and also highlights key analysis that needs to be completed in the near term. It also highlights essential ongoing planning initiatives and gas industry trends Avista will be monitoring as a part of its routine planning processes.

The analysis indicates there is no near term needs to acquire additional supply side resources to meet customer demand. However, Avista will perform its gate station analysis to assess if individual gate station deficiencies exist and discuss findings and potential solutions with Commission Staff. We will continue to coordinate the analytic efforts between Gas Supply, Gas Engineering and the interstate pipelines to conduct this analysis and if deficiencies are identified seek least-cost solutions.

Avista also believes in the pursuit of cost-effective demand-side solutions, but recognizes the challenges of the current low cost environment. IRP modeling versus operational business planning are different. Within the IRP, Washington and Idaho conservation measures are targeted to reduce demand by approximately 120,000 dekatherms in the first year (2013). In Oregon, conservation measures are targeted to reduce demand by approximately 24,600 dekatherms in the first year. When these aggregated savings and resultant avoided costs were incorporated into the business planning process, natural gas programmatic DSM was cost-ineffective. This resulted in Avista filing to suspend natural gas DSM programs in Washington and Idaho. An evaluation of Oregon program offerings is currently under evaluation.

We will monitor natural gas prices a signpost for increasing avoided costs. Should avoided costs increase we will evaluate our demand side programs for cost-effectiveness and be proactive in submitting to resume our natural gas demand side management options.

Key ongoing components of the Action Plan include:

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated resource deficiencies arising from exposure to “flat demand” risk. This will include providing Commission Staff with IRP demand forecast-to-actual variance analysis on customer growth and use per customer. This information will be provided in Avista’s updates to each Commission Staff at least bi-annually.
- Pursue the possibility of a regional elasticity study through the Northwest Gas Association or possibly the American Gas Association.
- Assess potential demand impact from NGV/CNG vehicles and other new uses of natural gas to Avista.
- Continue to monitor supply resource trends including the availability and price of natural gas to the region, exporting LNG, Canadian natural gas supply availability and interprovincial consumption, as well as pipeline and storage infrastructure availability.
- Monitor availability of current resource options and assess new resource lead time requirements relative to when resources are needed to preserve flexibility.
- Regularly meet with Commission Staff members to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

CONCLUSION

Continued slow growth and the declining use- per- customer resulted in lower demand when compared to our last IRP. Current IRP analysis indicates no near-term need for the acquisition of additional supply-side resources. While Avista believes adoption of conservation is the best strategy for minimizing costs to our customers and promoting a cleaner environment, current and forecasted low prices challenge the cost-effectiveness of demand side measures at the program level. The IRP process has many objectives, but foremost, is to ensure that proper planning will enable us to continue delivering safe, reliable and economic natural gas service to our customers well into the future. We are confident this plan delivers on that objective.

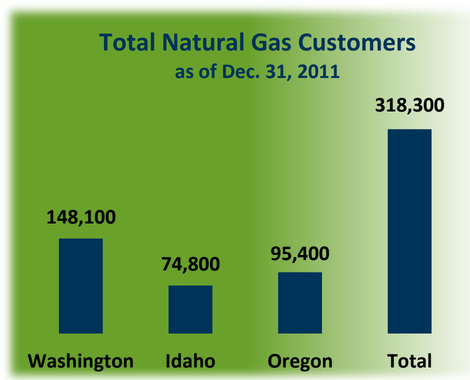
CHAPTER 2 || INTRODUCTION

OUR COMPANY

Avista is involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista was founded in 1889 as Washington Water Power and has been providing reliable, efficient and competitively priced energy to customers for over 120 years.

Avista entered the natural gas business with the purchase of Spokane Natural Gas Company in 1958. In 1970 it expanded into natural gas storage with Washington Natural Gas (now Puget Sound Energy) and El Paso Natural Gas (its interest subsequently purchased by Williams-Northwest Pipeline (NWP)) to develop the Jackson Prairie natural gas underground storage facility in Chehalis, Wash. In 1991 we added 63,000 customers with the acquisition of CP National Corporation's Oregon and California properties. Avista subsequently sold the California properties and its 18,000 South Lake Tahoe customers to Southwest Gas in 2005. Avista currently provides natural gas service to approximately 318,000 customers in eastern Washington, northern Idaho and several communities in northeast and southwest Oregon.

SERVICE TERRITORIES AND NUMBER OF CUSTOMERS



Avista manages its natural gas operation through two operating divisions – North and South:

- The North Division covers about 26,000 square miles, primarily in eastern Washington and northern Idaho. Over 840,000 people live in Avista's Washington/Idaho service area. It includes urban areas, farms, timberlands and the Coeur d'Alene mining district. Spokane is the largest metropolitan area with a regional population of approximately 450,000 followed by the Lewiston, Idaho/Clarkston, Wash. and Coeur d'Alene, Idaho. The North Division has about 74 miles of natural gas distribution mains and 5,000 miles of distribution lines. Natural gas is received at more than 40 points along interstate pipelines and distributed to over 222,000 customers.
- The South Division serves four counties in southwest Oregon and one county in northeast Oregon. The combined population of these two areas is over 480,000 residents. The South

Division includes urban areas, farms and timberlands. The Medford, Ashland and Grants Pass areas, located in Jackson and Josephine Counties, is the largest single area served by Avista in this division, with a regional population of approximately 280,000 residents. The South Division consists of about 67 miles of natural gas distribution mains and 2,000 miles of distribution lines. Natural gas is received at more than 20 points along interstate pipelines and distributed to almost 96,000 residential, commercial and industrial customers.

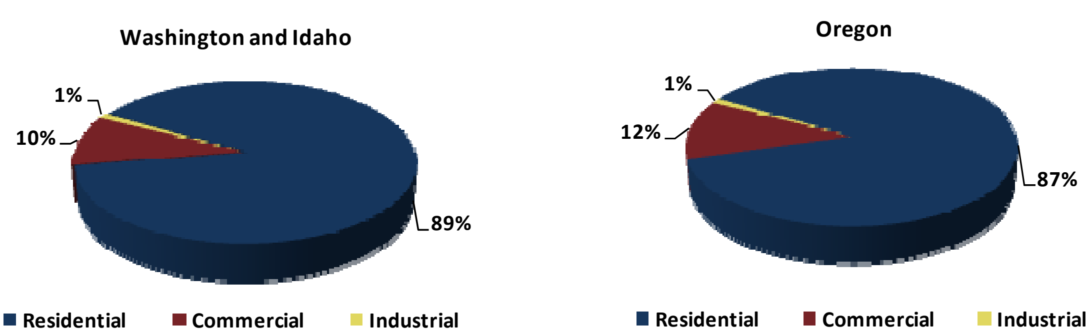
OUR CUSTOMERS

We provide natural gas services to two customer classifications – "core" and "transportation only." Core or retail customers purchase natural gas directly from us with delivery to their home or business under a bundled rate. Those core customers on firm rate schedules are entitled to receive whatever volume of gas is needed. There are some core customers who are on interruptible rate schedules. These customers pay a lesser rate than firm customers since their service can be interrupted. These interruptible customers are not considered in our peak day IRP planning.

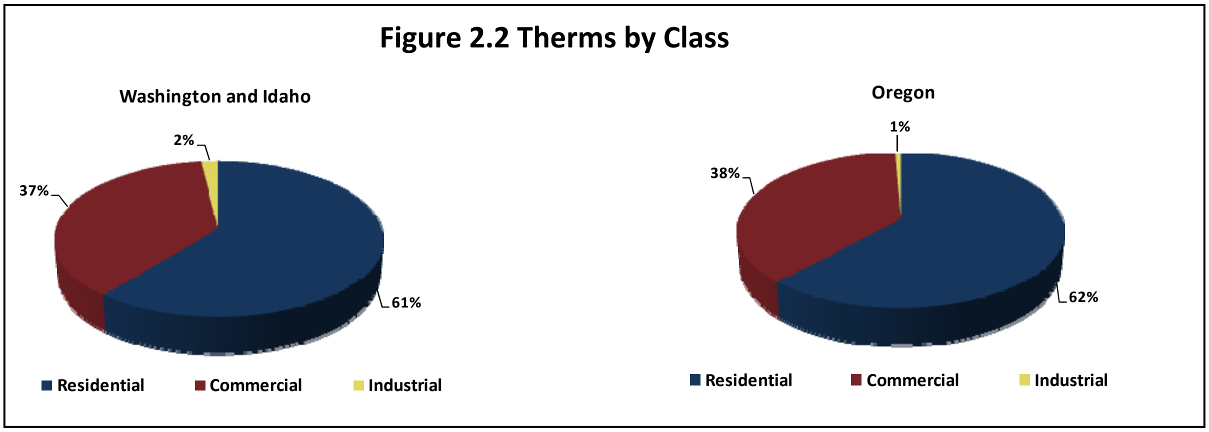
Transportation-only customers purchase natural gas from third parties who deliver their gas to our distribution system. We then deliver this gas to their business charging a distribution rate only. This delivery service can be interrupted by Avista following our priority of service tariff. Since our transportation-only customers purchase their own gas and utilize their own interstate pipeline transportation contracts they are excluded from this long-term resource planning exercise.

Our core or retail customers are further divided into three categories – residential, commercial and industrial. Most of our customers are residential, followed by commercial. Relatively few are industrial accounts (Figure 2.1).

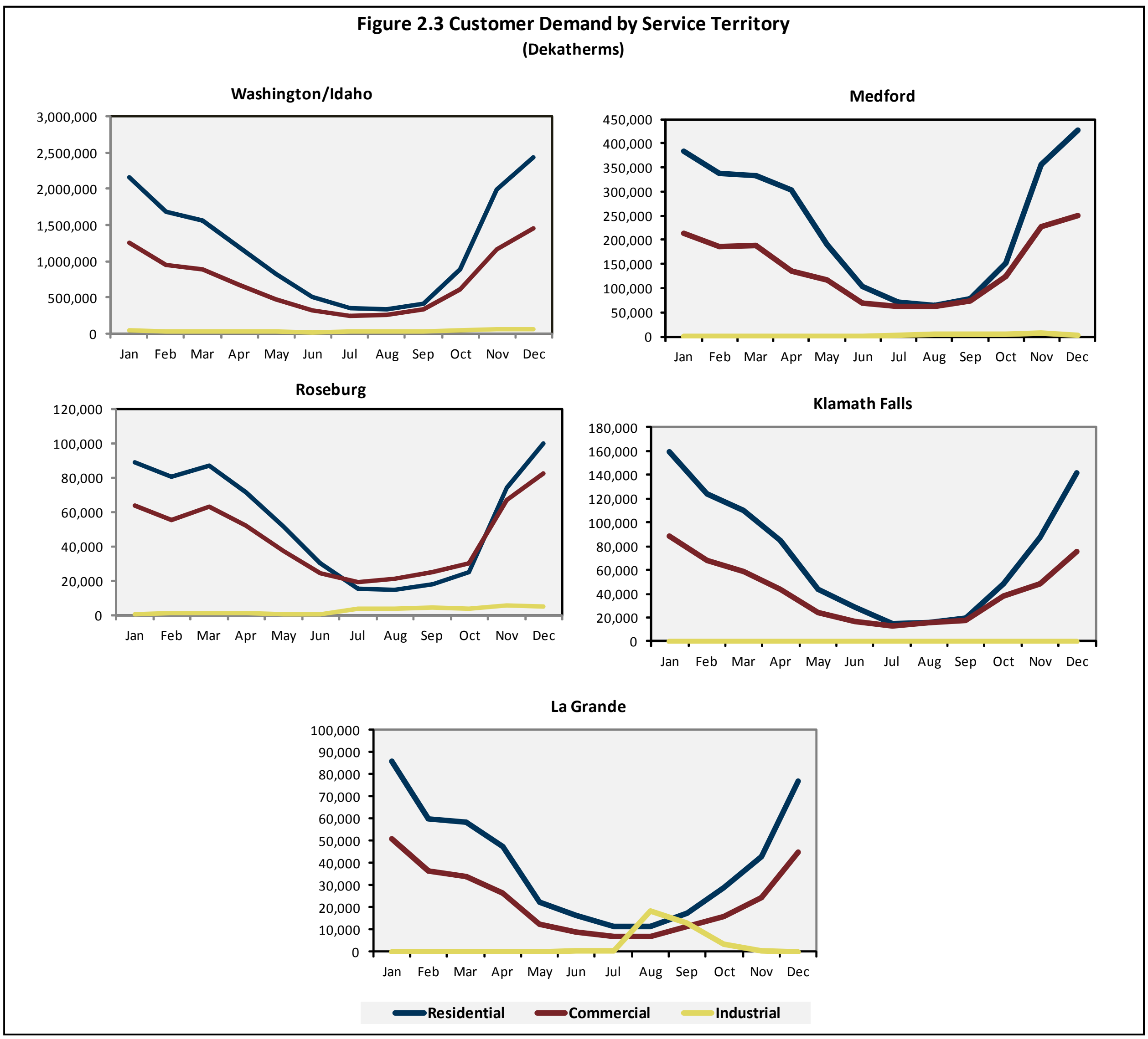
Figure 2.1 Firm Customer Mix



The mix is more balanced between residential and commercial accounts on an annual volume basis (Figure 2.2). Volume consumed by core industrial customers is not significant to the total, partly because most industrial customers in our service territories are transportation only customers.



Core customer demand is seasonal, especially by our residential accounts in our service territories with colder winters (Figure 2.3). Industrial demand, which is typically not weather sensitive, has very little seasonality. However, our La Grande service territory has several agricultural processing facilities, classified as industrial, that produce a late summer season al demand spike.



INTEGRATED RESOURCE PLANNING

In order to ensure that our core firm customers are provided with long-term reliable natural gas service at a competitive price, we undertake a comprehensive analytical process through the IRP. We evaluate, identify and plan for the acquisition of the best-risk, least-cost portfolio of existing and future resources to meet average daily and peak-day demand delivery requirements over a 20-year planning horizon.

PURPOSE OF THE IRP

This document has several objectives:

- Provides a comprehensive long-range planning tool
- Fully integrates forecasted requirements with existing and potential resources
- Determines the most cost-effective, risk-adjusted means for meeting demand requirements
- Responds to Washington, Idaho and Oregon rules and orders

AVISTA'S IRP PROCESS

The IRP process considers:

- Customer growth and usage
- Weather planning standard
- DSM opportunities
- Existing and potential supply-side resource options
- Current and potential legislation/regulation
- Risk

PUBLIC PARTICIPATION

Members of Avista's TAC play a key role and have a significant impact in development of the IRP. TAC members include Commission Staff, peer utilities, public interest groups, customers, academics, government agencies and other interested parties. A list of TAC members is in Appendix 1.1 TAC members provide important input on modeling, planning assumptions and the general direction of the process.

Avista sponsored four TAC meetings to facilitate stakeholder involvement in the 2012 IRP. The first meeting convened on Jan. 17, 2012 and the last meeting was held on April 17, 2012. A broad spectrum of stakeholders was represented at each meeting. The meetings focused on specific planning topics, reviewed the status and progress of planning activities and solicited input on the IRP development. A draft of this IRP was provided to TAC members on May 25, 2012. We gained valuable input from the interaction and communication with TAC members and express our sincere thanks and appreciation for their contributions and participation.

Preparation of the IRP is a coordinated endeavor by several departments within Avista with involvement and guidance from management. We are grateful for these efforts and contributions.

REGULATORY REQUIREMENTS

Avista submits an IRP to the public utility commissions in Washington, Idaho and Oregon every two years as required by state regulation.[1] We will file our IRP with all three Commissions on or before Aug. 31, 2012. We have a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a means for identifying and evaluating potential resource options and as a process to establish an Action Plan for resource decisions. Ongoing investigation, analysis and research may cause us to determine that alternative resources are more cost effective than resources selected in this IRP. We will continue to review and refine our understanding of resource options and will act to secure these risk-adjusted, least-cost options when appropriate.

PLANNING MODEL

Consistent with prior IRPs is the use of SENDOUT®, the computer planning model we use to perform comprehensive and effective natural gas supply planning and analysis. SENDOUT® is a linear programming-based model that is widely used in the industry to solve natural gas supply, storage and transportation optimization problems. This model uses present value revenue requirement (PVRR) methodology to perform least-cost optimization based on daily, monthly, seasonal and annual assumptions related to:

- Customer growth and customer natural gas usage to form demand forecasts
- Existing and potential transportation and storage options
- Existing and potential natural gas supply availability and pricing
- Revenue requirements on all new asset additions
- Weather assumptions
- Demand-side management

We have also incorporated the Monte Carlo simulation module within SENDOUT® to simulate weather and price uncertainty. The module uses Monte Carlo functionality to generate simulations of weather and price to provide a probability distribution of results from which decisions can be made. Some examples of the types of analysis Monte Carlo simulation provides include:

- Price and weather probability distributions
- Probability distributions of costs (i.e. system costs, storage costs, commodity costs)
- Resource mix (optimally sizing a contract or asset level of various and competing resources)

These computer-based planning tools were used to develop our 20-year best cost/risk resource portfolio plan to serve customers.

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1 In Washington the IRP requirements are outlined in WAC 480-90-238 entitled "Integrated Resource Planning." In Idaho the IRP requirements are outlined in Case No. GNR-G-93-2, Order No. 25342. In Oregon the IRP requirements are outlined in Order Nos. 07-002, 07-047 and 08-339. Appendix 2.2 provides details of these requirements and how they are met.

PLANNING ENVIRONMENT

Although we prepare and publish an IRP biannually, the process is ongoing, taking into account new information and developments. In “normal” circumstances, the process can become complex as underlying assumptions evolve and impact previously completed analyses. Every planning cycle has challenges and uncertainties; this cycle was no different. The demand for natural gas has undergone extraordinary changes due to recessionary impacts. Residential, commercial and industrial demand has flattened. Renewable portfolio standards and the announcement of coal plant retirements have increased the need for future gas-fired generation and natural gas vehicles are once again in vogue. The supply picture has also undergone a makeover. The “Shale Gale” – in its infancy during the last planning cycle – has since grown up. While there continues to be questions about how vast the resource base is, its environmental impacts and how much can continue to be produced at these pricing levels, it has proved to be a “game changer.”

‖ IRP PLANNING STRATEGY

Planning for an uncertain future requires robust analysis that encompasses a wide range of possibilities. We have determined our approach needs to:

- Recognize historical trends may be fundamentally altered
- Critically review all assumptions
- Stress test assumptions via sensitivity analysis
- Pursue a spectrum of possible scenarios
- Develop a flexible analytical framework to accommodate changes
- Maintain a long-term perspective

With these objectives in mind we believe we have developed a strong strategy encompassing all required planning criteria that allowed us to produce a complete IRP that effectively analyzes risks and resource options, which sufficiently ensure our customers will receive safe and reliable energy delivery services well into the future with the best-risk, lease-cost, long-term solutions.

CHAPTER 3 ‖ DEMAND FORECASTS

OVERVIEW

The integrated resource planning process begins with the development of forecasted demand. Understanding and analyzing key demand drivers and their potential impact on our forecasts is vital to the planning process. Utilization of historical data provides a reliable baseline, however it is important to remember that past trends may not be indicative of future trends. The permanent long term effects of the recession will not be fully realized for many years. This uncertainty leads us to consider a range of scenarios to evaluate and prepare for a broad spectrum of outcomes.

DEMAND AREAS

Eight demand areas, structured around the pipeline transportation resources that serve them, were defined with the SENDOUT® computer model (Table 3.1). These demand areas are aggregated into four service territories and further summarized into two divisions for presentation throughout this IRP.

Table 3.1 Geographic Demand Classifications

Demand Area	Service Territory	Division
Spokane NWP	Washington/Idaho	North
Spokane GTN	Washington/Idaho	North
Spokane Both	Washington/Idaho	North
Medford NWP	Medford/Roseburg	South
Medford GTN	Medford/Roseburg	South
Roseburg	Medford/Roseburg	South
Klamath Falls	Klamath Falls	South
La Grande	La Grande	South

DEMAND FORECAST METHODOLOGY

Avista uses the IRP process to develop two types of demand forecasts – “annual” and “peak day.” Annual average demand forecasts are useful for several purposes, including preparing revenue budgets, developing natural gas procurement plans and preparing purchased gas adjustment filings. Peak day demand forecasts are critical for determining the adequacy of existing resources or the timing for acquiring new resources to meet our customers’ natural gas needs in extreme weather conditions throughout the planning period.

In general, if existing resources are sufficient to meet peak day demand, they will be sufficient to meet annual average day demand. Developing annual average demand first and evaluating it against existing resources is an important step in understanding the performance of the portfolio under normal circumstances. It also facilitates synchronization of modeling processes and assumptions for all planning purposes.

Peak weather analysis aids in assessing not only resource adequacy but differences, if any, in resource utilization. For example, storage may be dispatched differently under peak weather scenarios.

DEMAND MODELING EQUATION

Because natural gas demand can vary widely from day to day, especially in winter months when heating demand is at its highest, developing daily demand forecasts is essential. In its most basic form, demand is a function of customer base usage (non-weather sensitive usage) plus customer weather sensitive usage. This can be expressed by the following general formula:

Table 3.2 Basic Demand Formula

# of customers **x** Daily **base usage** / customer
Plus
# of customers **x** Daily **weather sensitive** usage / customer

More specifically, SENDOUT® requires inputs as expressed in the below format to compute daily demand in dekatherms (Dth):

Table 3.3 SENDOUT® Demand Formula

# of customers **x** Daily **Dth base usage** / customer
Plus
# of customers **x** Daily Dth **weather sensitive** usage / customer **x** # of daiy degree days

This calculation is performed by SENDOUT® for each day for each customer class and each demand area. The base and weather sensitive usage (heating degree day usage) factors are customer demand coefficients developed outside the SENDOUT® model and capture a variety of demand usage assumptions. This is discussed in more detail in the Use-per-Customer Forecast section below. The number of daily degree days is simply heating degree days (HDDs), which are further discussed in the Weather Forecast section later in this chapter.

CUSTOMER FORECASTS

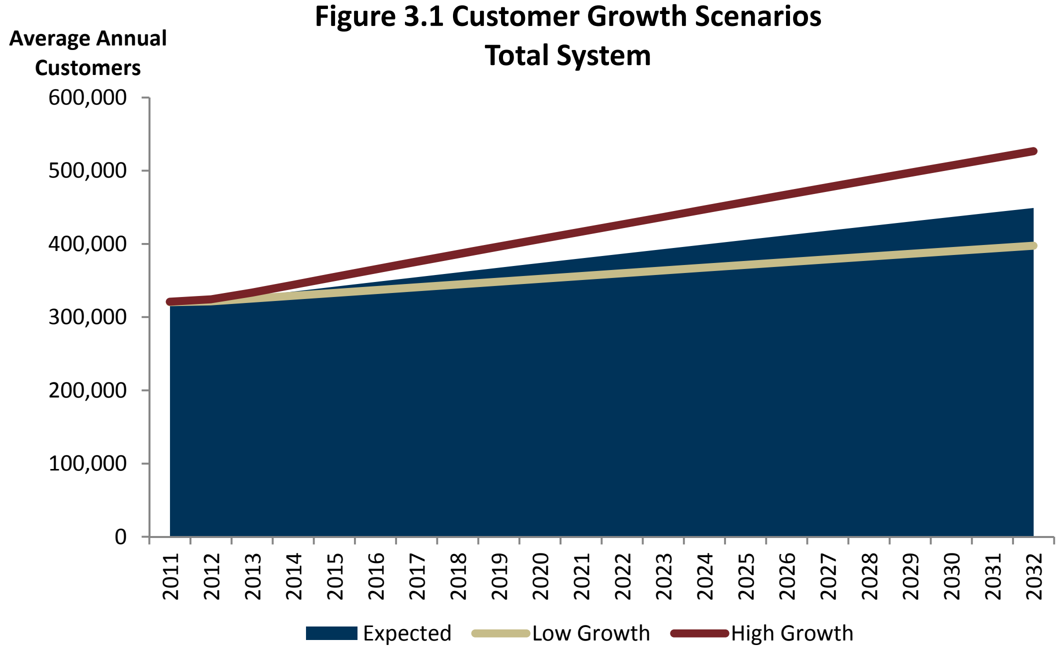
Avista's customer base is segregated into three categories: residential, commercial and industrial. For each of the customer categories we develop our customer forecasts by starting with national economic forecasts and then drilling down into regional economies. Population growth expectations and employment are key drivers in regional economic forecasts and are useful in estimating natural gas customers. We contract with Global Insight, Inc. for long-term regional economic forecasts. A description of the Global Insight forecasts is found in our customer forecasts detail in Appendix 3.1. We combine this data with local knowledge about sub-regional construction activity, age and other demographic trends and historical data to develop our 20-year customer forecasts.

The annual growth for each state is allocated so that the total equals the sum of the parts. These forecasts are used by the distribution engineering group for optimizing decisions within these geographic sub-areas and facilitating integrated forecasting and planning within Avista (see further discussion in Chapter 8 – Distribution Planning).

Forecasting customer growth is an inexact science so it is important to consider alternative forecasts. Two alternative growth forecasts were developed for consideration in this IRP. In past IRPs we have used 25 years of historical growth rates to derive our low and high growth sensitivities. This historical look back gave us growth assumptions of 50% greater than expected and 50% lower than expected for our high and low growth sensitivities. Utilizing historical data provided some comfort with the reasonableness of these growth forecasts.

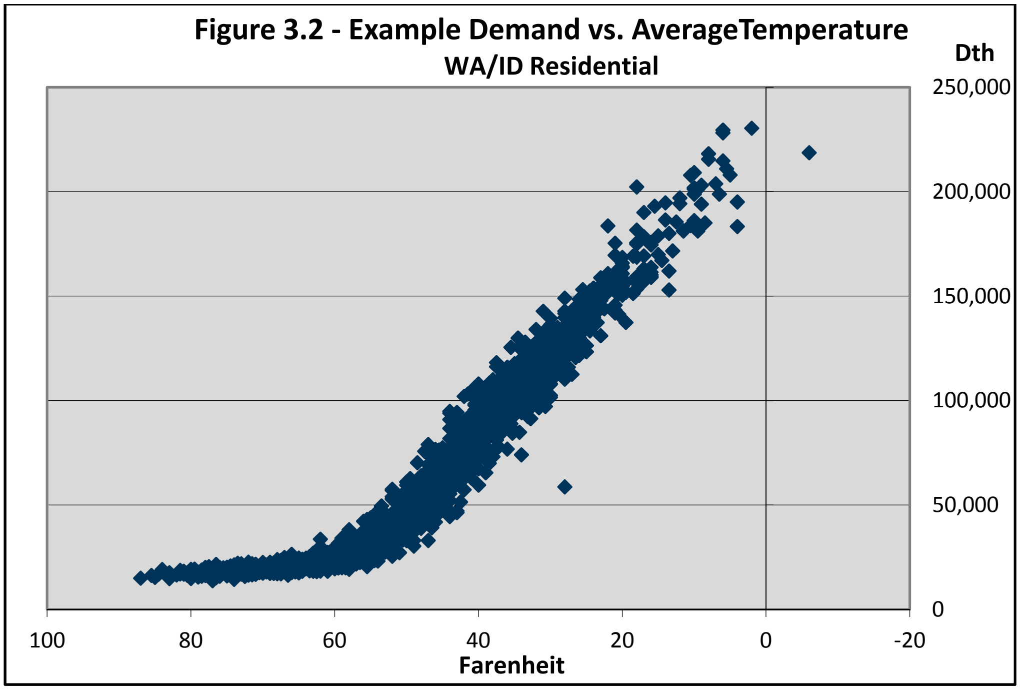
However, recent events have impacted our economy and there is much uncertainty about when and how much recovery will occur. The past may not be indicative of future behaviors. Growth experienced in the last couple of years is low. In examining recent trends and comparing to history the range of growth seems asymmetric. To this end we utilized forecasted information from the Washington State Office of Financial Management (OFM) to prepare the high and low growth sensitivities. The OFM forecasts the potential for growth rates 40% below and 60% above current growth rates. These three customer growth forecasts are shown in Figure 3.1. Detailed customer count data by region and class for all three scenarios is in Appendix. 3.2.

Figure 3.1 Customer Growth Scenarios
Total System



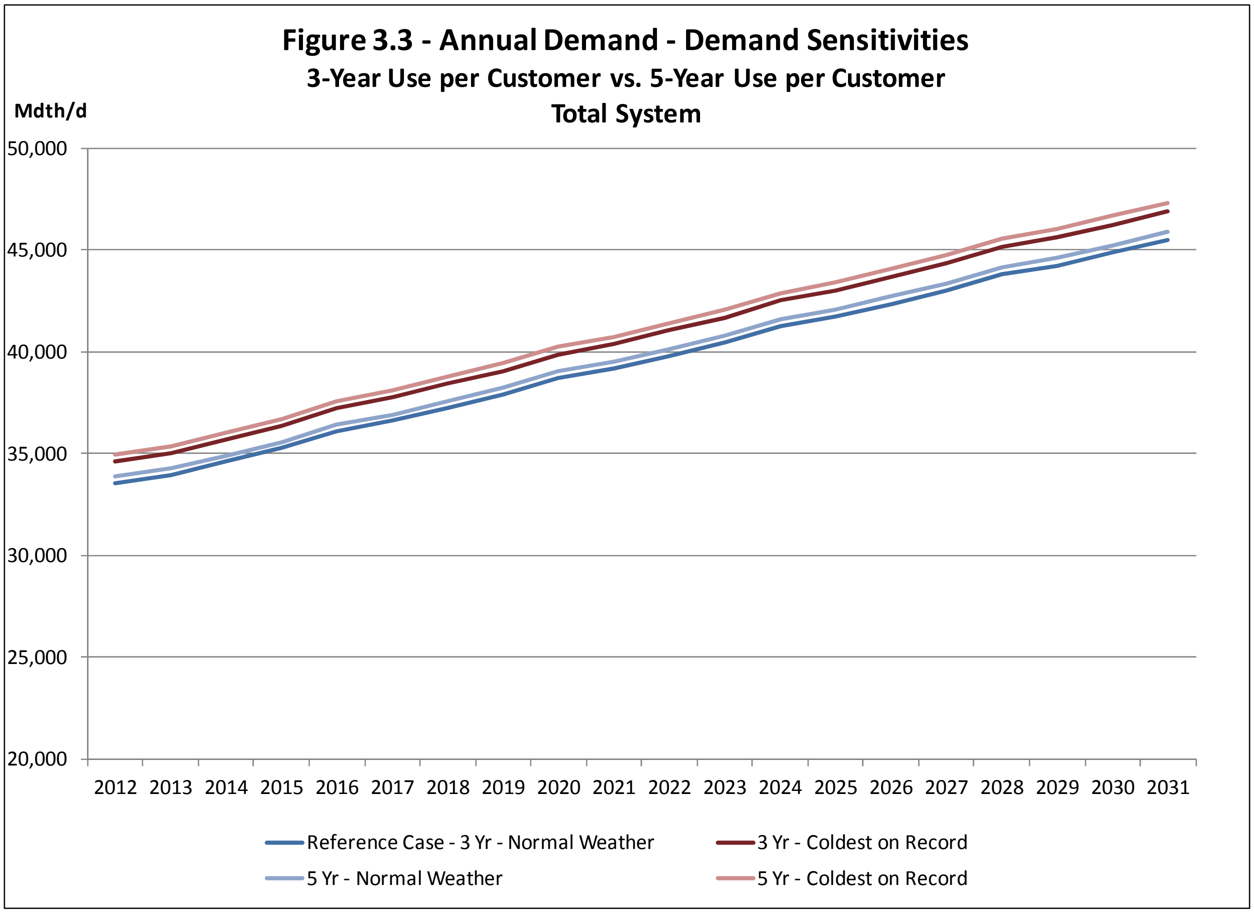
USE-PER-CUSTOMER FORECAST

The goal for a use-per-customer forecast is to develop base and weather sensitive demand coefficients that can be combined and applied to HDD weather parameters to reflect average use per customer. This produces a very reliable forecast because of the high correlation between usage and temperature as depicted in the example scatter plot in Figure 3.2.



The first step in developing demand coefficients was gathering daily historical gas flow data for all of our city gates. Our preference to use city gate data over revenue data is due to the tight correlation between weather and demand. Our revenue system does not capture data on a daily basis and therefore, makes a statistical analysis with tight correlations virtually impossible. We do reconcile city gate flow data to revenue data to ensure that we are properly capturing total demand.

The historical city gate data was gathered, segregated by service territory/temperature zone and then by month. In our last IRP we used three years of historical data to derive our use per customer coefficients. Continuing with our theme of challenging each assumption we looked at varying the number of years of historical data. We analyzed five years, three years and two years of use per customer. We decided that two years was not necessarily indicative of future use per customer behavior nor does it incorporate enough data points to make a comprehensive long term analysis. Five years incorporated some years of higher use per customer, which may overstate use due to current recessionary impacts and conservation savings. Three years seemed to strike the right balance between historical and contemporaneous customer usage patterns. Figure 3.3 illustrates the annual demand differences between the three year and five year use per customer with normal and peak weather conditions.



To calculate base usage, three years of July and August data was used to derive coefficients. Average usage in these months divided by average number of customers provides the base usage coefficient input into SENDOUT®.This calculation is done for each area and customer class based on customer billing data demand ratios.

To derive weather sensitive demand coefficients, for each monthly data subset, we removed base demand from the total and plotted usage by HDD in a scatter plot chart to visually verify correlation. We then applied linear regression to the data by month to capture the linear relationship of usage to HDD. The slopes of the resulting lines are the monthly weather sensitive demand coefficients input into SENDOUT®. Again, this calculation is done by area and by customer class using allocations based on customer billing data demand ratios.

In extreme weather conditions, demand can sometimes begin to flatten out relative to the linear relationships at less extreme temperatures. This occurs, for example, when appliances such as furnaces reach maximum output and do not consume any more natural gas regardless of how much colder temperatures get. We sought to capture this phenomenon through development of super peak coefficients.

The methodology for deriving super peak coefficients was exactly the same as deriving weather sensitive demand coefficients except, instead of forming data subsets by month, a dataset was created using temperature (specifically HDD's greater than 65). The line slope from the regression on this data was typically flatter relative to the other monthly weather sensitive demand coefficients. One inherent drawback to this methodology is the lack of sufficient data points to develop a strong linear relationship.

More years of data can help, but the older data becomes less and less relevant to current demand relationships. We will continue to test this theory and monitor trends.

As a final step, to check coefficient reasonableness, we applied the coefficients to actual customer count and weather data to backcast demand. This was compared to actual demand with satisfactory results. The regression calculations and coefficients can be found in Appendix 3.3.

WEATHER FORECAST

The last input in the demand modeling equation is weather (specifically HDDs). We obtain the most current 30 years of daily weather data from the National Oceanic Atmospheric Administration (NOAA), convert it to HDDs and compute an average for each day to develop our weather forecast. For Oregon we use four weather stations, corresponding to the areas where natural gas services are provided. HDD weather patterns between these areas are uncorrelated. For the eastern Washington and northern Idaho portions of our service area weather data for the Spokane Airport is used, as HDD weather patterns within that region are correlated.

The NOAA 30-year average weather (adjusted for global warming – see below) serves as the base weather forecast that is used to prepare the annual average demand forecast. In preparing the peak day demand forecast we adjust average weather to reflect a five-day cold weather event. This consists of adjusting the middle day of the five-day cold weather event to the coldest temperature on record for a service territory, as well as adjusting the two days either side of the coldest day to temperatures slightly warmer than the coldest day. For our Washington/Idaho and La Grande service territories, we model this event on and around February 15 each year. For our southwestern Oregon service territories (Medford, Roseburg, Klamath Falls) we model this event on and around December 20 each year.

The following describes specific details on the coldest days on record for each service territory:

- On Dec. 30, 1968, the Washington/Idaho service area experienced the coldest day on record, an 82 HDD for Spokane. This is equal to an average daily temperature of -17 degrees Fahrenheit. Only one 82 HDD has been experienced in the last 40 years for this area; however, within that same time period, 80, 79 and 74 HDD events occurred on Dec. 29, 1968, Dec. 31,1978, and January 5, 2004, respectively.
- On Dec. 9, 1972, Medford experienced the coldest day on record, a 61 HDD. This is equal to an average daily temperature of 4 degrees Fahrenheit. Medford has experienced only one 61 HDD in the last 40 years; however, it has also experienced 59 and 58 HDD events on Dec. 8, 1972, and Dec. 21, 1990, respectively.
- The other three areas in Oregon have similar weather data. For Klamath Falls, a 72 HDD occurred on Dec. 21, 1990, in La Grande a 74 HDD occurred on Dec. 23, 1983, and a 55 HDD occurred in Roseburg on Dec. 22, 1990. As with Washington/Idaho and Medford, these days are used as the peak day weather standard for modeling purposes.

Utilizing a peak planning standard of the coldest temperature on record may seem aggressive given we are using, in some cases, a temperature experienced only once. Given the potential impacts of an extreme weather event on our customers' personal safety and property damage to customer appliances and company infrastructure, we believe it is a prudent planning standard.

We do analyze an alternate planning standard using the coldest temperature in the last twenty years For our Washington/Idaho service area we use a 74 HDD, which is equal to an average daily temperature of -9 degrees Fahrenheit. In Medford the coldest in twenty year is a 54 HDD, equivalent to a temperature of 11 degrees Fahrenheit. In Roseburg the coldest in twenty year is a 48 HDD, equivalent to a temperature of 17 degrees Fahrenheit. In Klamath Falls the coldest in twenty is a 64 HDD, equivalent to a temperature of 1 degree Fahrenheit. In La Grande the coldest in twenty years is a 68 HDD, equivalent to a temperature of -3 degrees Fahrenheit.

These HDDs by area, class and by day entered into SENDOUT® can be found in Appendix 3.4.

GLOBAL WARMING

Consistent with past IRPs, we adjusted the NOAA weather data to incorporate estimates for global warming in developing our HDD forecasts. This was based on extensive analysis of historical weather data in each of the areas we serve. Adjustments were applied to daily NOAA normal weather data and include a phase-in over the first ten years of our planning horizon. The effect of the adjustments, all else equal, results in declining annual demand over time. Appendix 3.5 summarizes our historical analysis and adjustment factors.

The analysis identified a gradual warming trend in the historical data; however we were unable to discern any definitive evidence to support a peak day warming trend. We continue to search but have be unsuccessful in finding supporting studies or analysis on the topic and, after discussion with our TAC, determined we would not make warming trend adjustments to our peak day weather events in our HDD forecast. Therefore, our modeling and analysis with respect to peak day planning is unaffected by global warming. Additional information on this topic is in Appendix 3.5.

DEVELOPING A REFERENCE CASE

To adjust for uncertainty, we developed a dynamic demand forecasting methodology that is flexible to changing assumptions. To understand how various alternative assumptions influence forecasted demand we needed a reference point for comparative analysis. For this we define a reference case demand forecast (Figure 3.4). We stress that this case is not intended to reflect anything other than a simple assumption start point.

Figure 3.4 - Reference Case Assumptions

1. Customer Annual Average Growth Rates

State	Residential	Commerical	Industrial
Washington	1.50%	1.60%	1.00%
Idaho	2.00%	1.70%	0.40%
Oregon	1.70%	1.30%	0.74%

2. Use Per Customer Coefficients

Flat Across All Classes

3-year Average Use per Customer per HDD by Area/Class

3. Weather

30-year Normal - NOAA (1981-2010)

Global Warming Adjustment

4. Elasticity

None

5. Demand Side Management

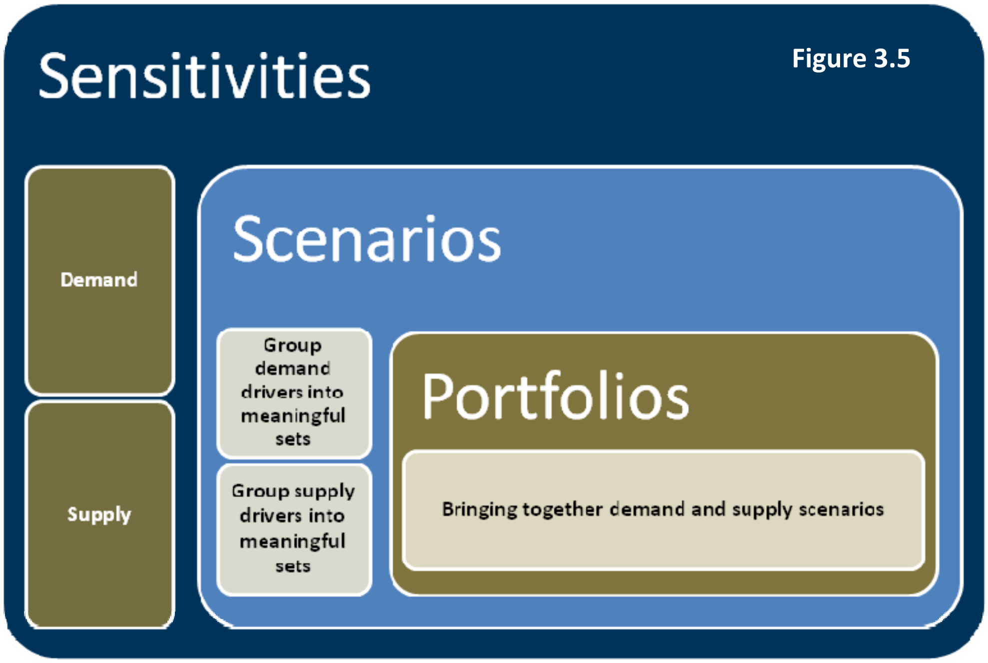
None

DYNAMIC DEMAND METHODOLOGY

The dynamic demand planning strategy critically examines a wide range of potential outcomes. The approach developed consists of:

- Identifying key demand drivers behind natural gas consumption
- Performing sensitivity analysis on each demand driver
- Combining demand drivers under various scenarios to develop alternative potential outcomes for forecasted demand
- Matching demand scenarios with supply scenarios to identify unserved demand

Figure 3.5 represents our methodology of starting with sensitivities, progressing to scenarios, and ultimately creating portfolios.



SENSITIVITY ANALYSIS

In analyzing demand drivers, we grouped them into two categories based on:

- **DEMAND INFLUENCING FACTORS** – Factors that directly influence the volume of natural gas consumed by our core customers
- **PRICE INFLUENCING FACTORS** – Factors that, through price elasticity response, indirectly influence the volume of natural gas consumed by our core customers

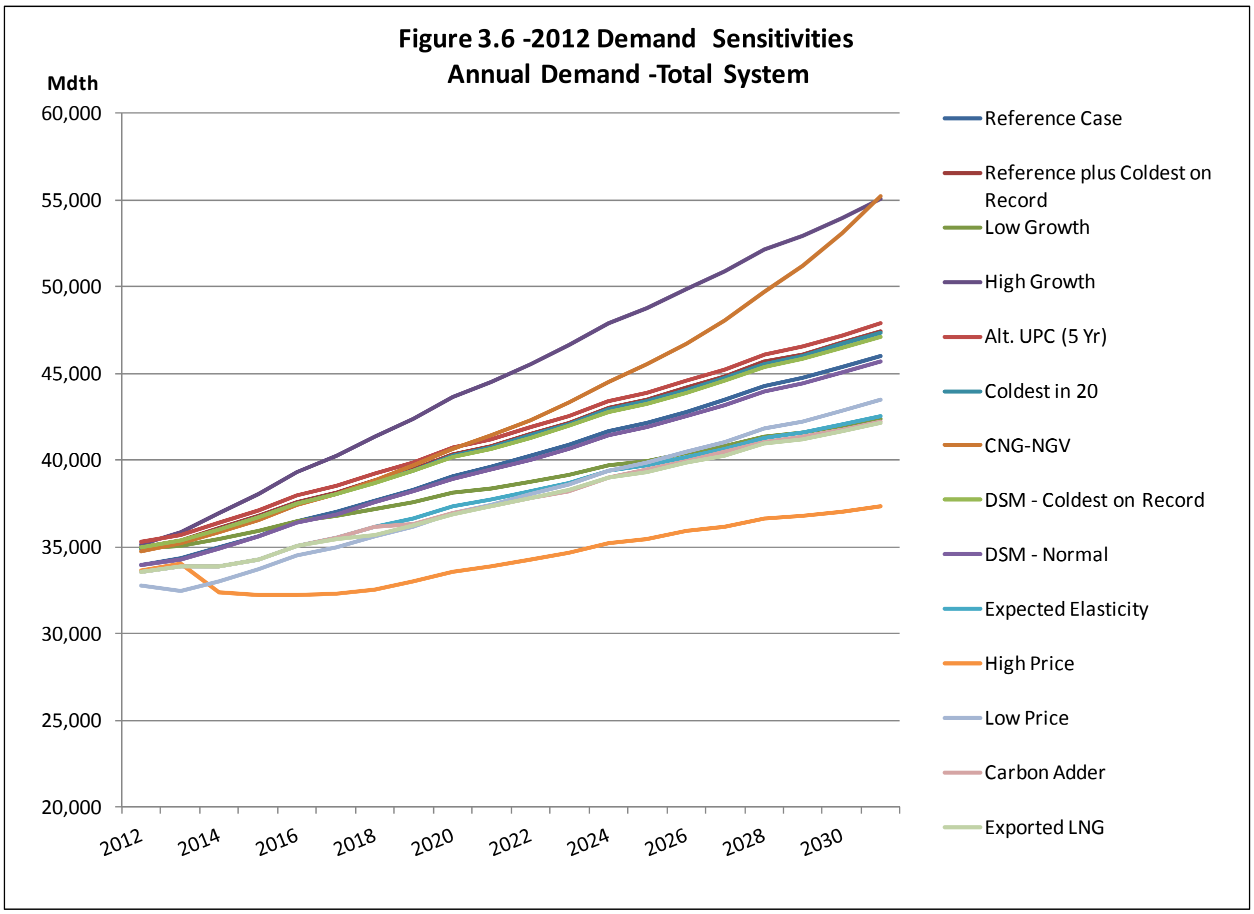
Once factors were identified, we developed sensitivities which we define as focused analysis of a specific natural gas demand driver and its impact on forecasted demand relative to our Reference Case when the underlying input assumptions are modified

Sensitivity assumptions reflect incremental adjustments we estimate are not captured in the underlying Reference Case forecast. We analyzed 14 demand sensitivities to determine the resultant effect relative to the reference case. Table 3.4 lists these sensitivities. More detailed information about these sensitivities can be found in Appendix 3.6.

Table 3.4 - Demand Sensitivities

Scenario	Influence	Weather	Growth	Use per Customer	Price Curve	Carbon Adder	LNG Adder	DSM	CNG/NGV	Elasticity
Reference Case	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Reference Case plus Peak Weather	Direct	Peak	Expected	3 year	Expected	No	No	No	No	No
High Growth Case	Direct	Peak	High	3 year	Expected	No	No	No	No	No
Low Growth Case	Direct	Peak	Low	3 year	Expected	No	No	No	No	No
Alternate Use per Customer	Direct	Peak	Expected	5 year	Expected	No	No	No	No	No
CNG/NGV Case	Direct	Peak	Expected	3 year	Expected	No	No	No	Yes	No
DSM	Direct	Normal	Expected	3 year	Expected	No	No	No	No	No
Peak plus DSM	Direct	Peak	Expected	3 year	Expected	No	No	Yes	No	No
Alternate Weather Planning Standard	Direct	Coldest in 20	Expected	3 year	Expected	No	No	Yes	No	No
Expected Elasticity	Indirect	Peak	Expected	3 year	Expected	No	No	No	No	Yes
Low Price	Indirect	Peak	Expected	3 year	Low	No	No	No	No	No
High Price	Indirect	Peak	Expected	3 year	High	No	No	No	No	No
Carbon Legislation	Indirect	Peak	Expected	3 year	Expected	Yes	No	No	No	No
Exported LNG	Indirect	Peak	Expected	3 year	Expected	No	Yes	No	No	No

Figure 3.6 shows the annual demand from each of the sensitivities we modeled.



SCENARIO ANALYSIS

Following our testing of the various sensitivities we grouped them into meaningful combinations of demand drivers to develop demand forecasts representing scenarios. Table 3.5 identifies the scenarios we developed. Our Average Demand Case is representative of what we would consider for normal planning purposes, such as corporate budgeting, procurement planning, and PGA/General Rate Cases. The

Expected Case reflects the demand forecast we believe is most likely given peak weather conditions. The High Growth/Low Price and Low Growth/High Price represent a forecasted range of possibilities for customer growth and future prices. The Alternate Weather Standard utilizes the coldest day in the last twenty years. Each of these scenarios helps provide us with sufficient "what if" analysis given the volatile nature of many key assumptions including weather and price. Appendix 3.6 lists the specific assumptions within the scenarios while Appendix 3.7 contains a detailed description of each scenario.

Table 3.5

Demand Scenarios
Average Demand
Expected Demand - Peak
High Growth/Low Price
Low Growth/High Price
Alternate Weather Standard

PRICE ELASTICITY

Historic natural gas price volatility has created challenges in projecting future natural gas prices. Now that shale gas has fundamentally altered the market for natural gas historic analysis may not be indicative of future behavior. Some believe price volatility will decrease due to the widespread availability of natural gas while others feel volatility could become greater as shale production profiles are much less predictable than conventional gas production. We acknowledge changing price levels influence usage so we incorporate a price elasticity of demand factor into our modeling assumptions to allow use per customer to vary into the future as our natural gas price forecast changes.

Price elasticity is usually expressed as a numerical factor that defines the relationship of a consumer's consumption change in response to price change. Typically, the factor is a negative number as consumers normally reduce their consumption in response to higher prices or will increase their consumption in response to lower prices. For example, a price elasticity factor of negative 0.13 means a 10% price increase will prompt a 1.3% consumption decrease and a 10% price decrease will prompt a 1.3% consumption increase.

We noted complex relationships influence price elasticity and given the new economic environment, we question whether current behavior will be considered normal or if customers will return historic usage patterns.

AGA PRICE ELASTICITY STUDY

From our participation in the 2007 AGA long-run price elasticity study, we received regional elasticity factors which compared favorably to our past estimates. Based on this corroboration we used a factor of negative .13 as our expected case factor to adjust use per customer coefficients.

In our last IRP we modeled a high and low price elasticity assumption due to the uncertainty in how our customers would respond to their evolving economic conditions. Utilizing the high elasticity assumption resulted in significant curtailment of demand which was much greater than historical experience. Alternatively low elasticity resulted in no meaningful reduction in demand. Our recent usage data indicates that even with declines in the retail rate for natural gas, use-per-customer continues to decline.

This is likely driven by a confluence of factors including high unemployment, increased investments in energy efficiency measures, building code improvements, behavioral changes and overall heightened focus of consumers' household budgets.

Based on our analysis of data since our 2009 IRP we find that the expected elasticity factor is a reasonable assumption and have decide to forgo utilizing a high or low elastic response in this IRP.

RESULTS

During 2012, our Average Case demand forecast indicates we will serve an average of 327,300 core natural gas customers with 33,200,000 dekatherms of natural gas. By 2031, we project 448,100 core natural gas customers with an annual demand of over 42,200,000 dekatherms. In Washington/Idaho, the number of customers is projected to increase at an average annual rate of 1.6 percent with demand growing at a compounded average annual rate of 1.3 percent. In Oregon, the number of customers is projected to increase at an average annual rate of 1.7percent, with demand growing 1.3 percent per year.

During 2012 our Expected Case demand forecast indicates we will serve an average of 327,300 core natural gas customers with 34,700,000 dekatherms of natural gas. By 2031 we project 448,100 core natural gas customers with an annual demand of over 43,744,000 dekatherms.

Figure 3.7 shows system forecasted demand for the demand scenarios on an **average daily basis** for each year[1].

[1] Appendix 3.9 shows gross demand, DSM savings, and net demand.

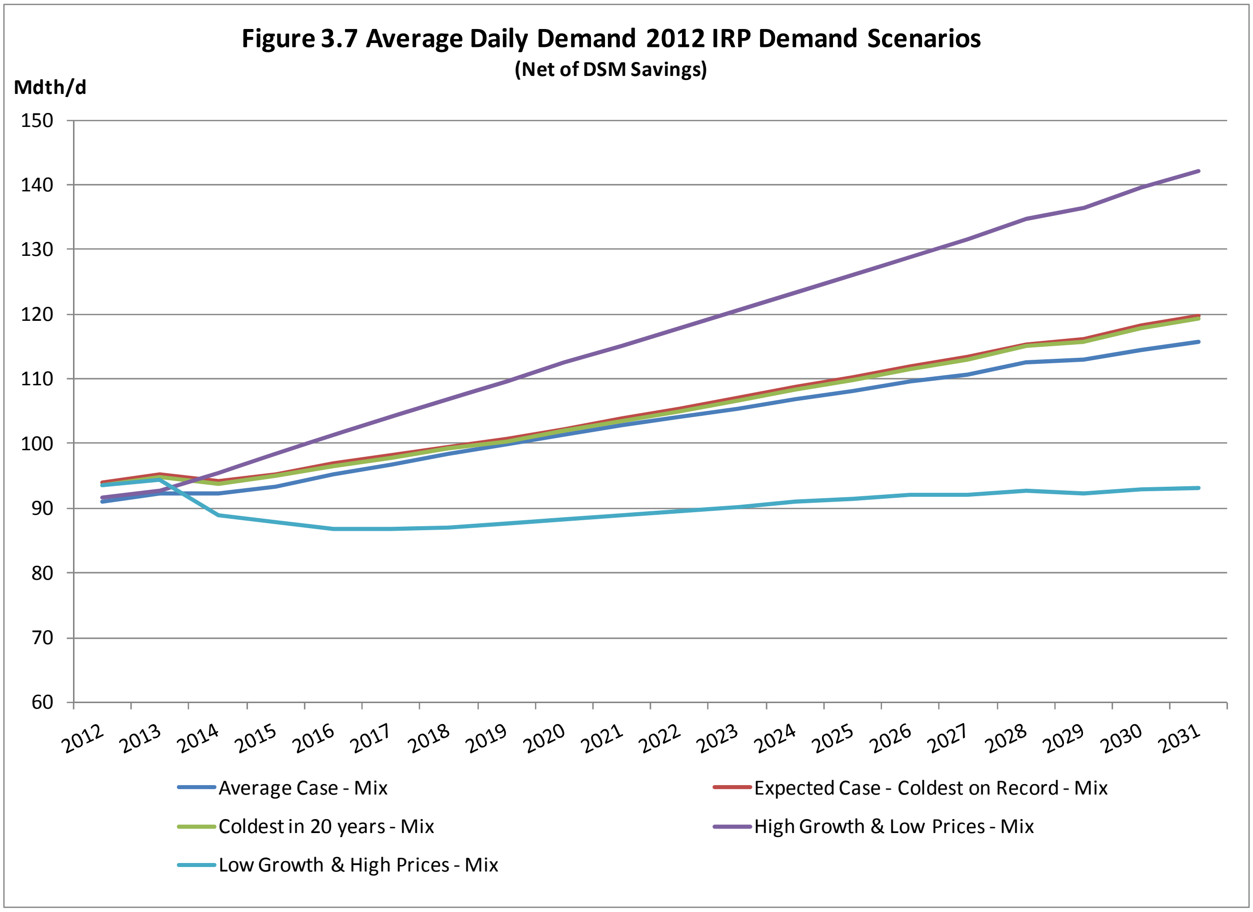
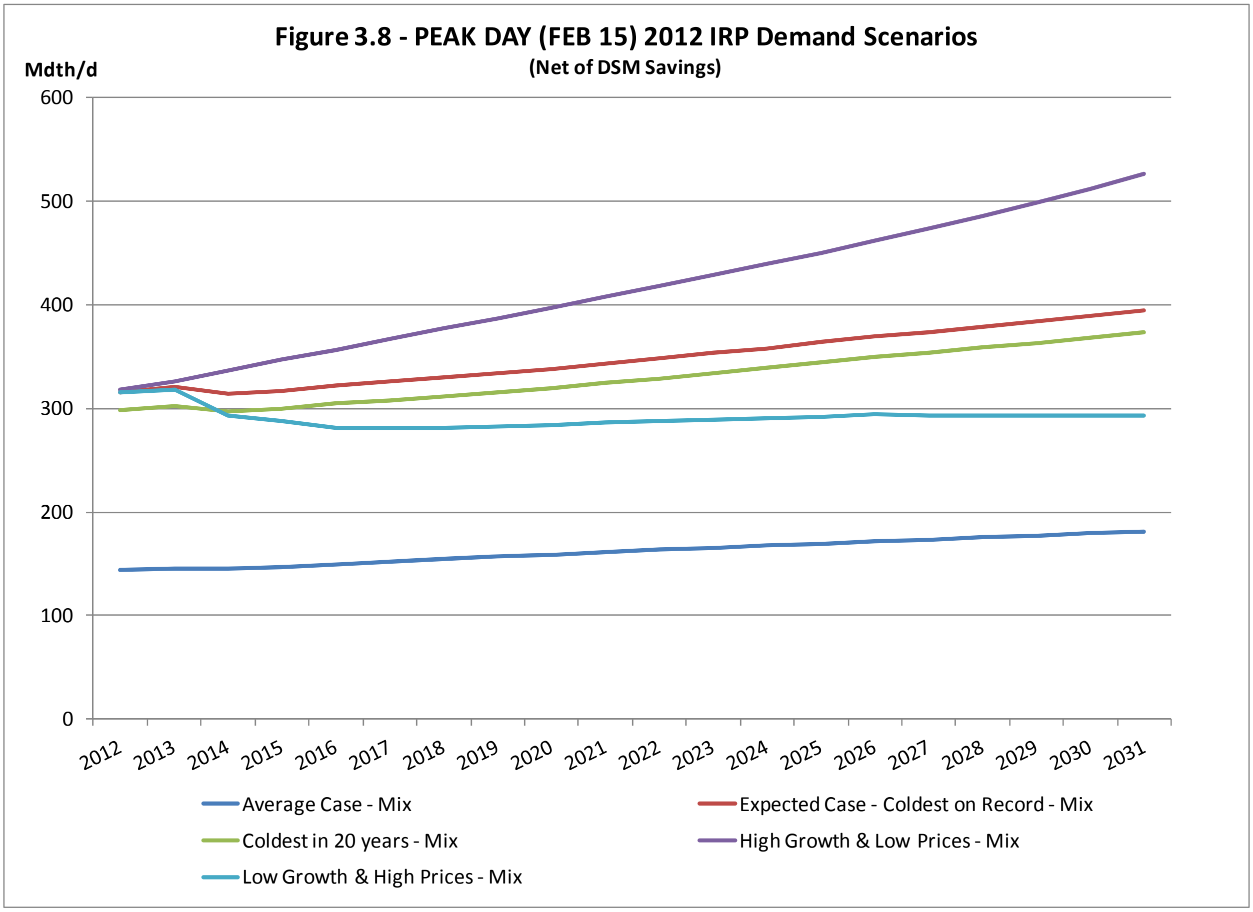


Figure 3.8 shows system forecasted demand for the Expected, High and Low Demand cases on a **peak day basis** for each year relative to the Average case average daily winter demand. Detailed data for all demand scenarios is in Appendix 3.8.



The purpose of the IRP is to balance forecasted demand with existing and new supply alternatives. Since new supply sources include conservation resources, which act as a demand reduction, the demand forecasts prepared and described in this section include existing efficiency standards and normal market acceptance levels. The methodology for modeling demand side management initiatives is described in Chapter 4 - Demand-Side Resources.

ALTERNATIVE FORECASTING METHODOLOGIES

There are many forecasting methods available and used throughout different industries.. We strive to use methods that enhance forecast accuracy, facilitate meaningful variance analysis and allow for modeling flexibility to incorporate differing assumptions. We believe our statistical methodology to be sound and provide us with a robust range of demand considerations. Our methodology allows for us to vary the results of our statistical inputs by considering both qualitative and quantitative factors. These factors can be derived from data or surveys of market information, fundamental forecasters, and industry experts. We are always open to new methods of forecasting demand and we continually assess which, if any, alternative methodologies to include in our dynamic demand forecasting methodology.

II ACTION ITEM

Demand forecasting is a critical component, careful evaluation of the current methodology and sufficient scenario planning is essential. The change in demand over recent years has been dramatic causing a heightened focus on variance analysis and trend monitoring. Current techniques have provided sound forecasts with appropriate variance capabilities. In the near term we have identified three key issues to investigate and monitor.

PRICE ELASTICITY

Our price elasticity analysis raised several issues. First, we noted the AGA factors were derived from annual demand data. This was satisfactory for our annual demand forecasting, but this raised a question whether the factors were applicable to peak demand analysis. We also use the same factors for residential and commercial customer classes even though the AGA factors were derived from residential customer data only.

We also noted that price signals to core customers are lagged and they are often insulated from volatile prices due to their exposure to tariff rates versus wholesale prices.

During our planning cycle we realized the effects of the recession and our demand forecast once again is lower than previous IRPs. Natural gas prices are at lows not seen in the last decade. Prices throughout this forecast are intended to increase, albeit moderately. The question still remains, how much more can/will customers curtail?

An action item from our last IRP had us make an inquiry to the AGA for an updated study. The AGA declined due to budget constraints. For the upcoming IRP cycle, we will consider working with a third-party, such as the NWGA, to conduct a price elasticity study and assess interest of other utilities in pursuing a regional study.

FLAT DEMAND RISK

Demand once again has “flattened” when compared to previous IRPs. The flattening of demand is due to many factors including moderate forecasted customer growth over the 20-year planning horizon (especially when compared to previous IRP customer forecasts) and declining use per customer due to behavioral changes driven by challenging economic conditions, increased investments in energy efficiency measures and enhanced building codes improving the efficiency of homes. The reduced demand pushes the need for resources out further into the future which is a good thing for customers, as no new investments in resources will be necessary in the foreseeable future. However, should there be a significant rebound in demand our resource needs become more imminent. We need continued visibility into our demand trends in order to identify signposts of accelerated recovery or changing usage behavior.

NATURAL GAS VEHICLE POTENTIAL

Robust availability of natural gas at economic prices has stimulated investments in NGV infrastructure. How much market penetration occurs nationally and regionally remains uncertain. Analysis and evaluation of our role in the NGV initiative is underway. We have included a scenario where NGV demand is served by Avista.

II CONCLUSION

Through our dynamic demand modeling process, we have considered a wide range of potential demand impacts of both changing natural gas prices and a changing economy. The result of those considerations is a reasonable array of outcomes with respect to core consumption of natural gas. While we recognize that the actual level of demand is dependent on a variety of factors, reviewing a range of potential outcomes allows us to plan more effectively as economic or pricing conditions change.

CHAPTER 4 DEMAND-SIDE RESOURCES

OVERVIEW

Avista has been offering natural gas Demand-Side Management (DSM) to its residential, commercial and industrial customers since 2001[1]. These programs result in multiple benefits including, but not limited to, reductions in customers' energy bills, reductions in natural gas supply-side resource needs and reductions in Green House Gas (GHG) emissions. These benefits make acquiring cost-effective demand-side efficiencies an appealing resource alternative which Avista believes is the best strategy for minimizing energy service costs to our customers while promoting a cleaner environment.

In response to the Washington Transportation and Utilities Commission (UTC) staff request of an independent, external Conservation Potential Assessment (CPA) pursuant to the Company's next IRP, Avista issued a Request for Proposal (RFP) for a CPA. Consequently, in preparation for this IRP, Global Energy Partners, an EnerNOC Company, was selected to conduct a CPA to forecast the 20-year DSM potential for Avista's natural gas service territory within Washington, Idaho, and Oregon. The DSM potential that was generated for Avista's service territory was then evaluated in SENDOUT® as a resource on par with other supply-side resources.

The SENDOUT® model understands that investments made in DSM are a long-term resource decision. Within SENDOUT® the aggregated potential and costs by region and class are tested against supply side resources. The model also understands that some potential may not be cost-effective in the initial forecast years; however the total cost over the life of the measure, coupled with the cumulative therms savings, is economic. Due to this modeling nuance, SENDOUT® typically selects most of the DSM potential.

The changing natural gas supply picture and lower prices have resulted in the decline of natural gas avoided costs. While this is good news for customers, these lower avoided costs add new challenges to offering a comprehensive natural gas DSM portfolio. The Company's 2012 DSM Business Plan forecasted non-cost-effective natural gas using the avoided costs from the 2009 Natural Gas IRP. A subsequent study done in February 2012 entitled "Review of Prospects and Strategies for the 2012 Avista Regular Income Natural Gas DSM Portfolio" projected that, with substantial modifications, the natural gas DSM portfolio could potentially be marginally cost-effective using a presumed 25 percent reduction in avoided cost.

Avista's originally anticipated assumption of 25 percent lower natural gas avoided costs was replaced with current IRP avoided costs which is a decrease of approximately 50 percent. Given these avoided costs, the Company's business planning projections indicate that the natural gas DSM portfolio will not be cost-effective. Evaluation of a number of scenarios to include additional adders for carbon/green house gases, distribution capacity adders, various allocations and categorizations of non-incentive utility cost, realization rates and net-to-gross ratios, as well as, evaluating the portfolio on a gross (including all program participants) rather than net (including only participants who adopted the measure as a result of the program) did not change the projected unfavorable portfolio cost-effectiveness.

[1] The Company operated natural gas DSM programs from 1995-1997 until natural gas avoided costs declined to the point at which natural gas DSM programs became cost-ineffective. At that time, the natural gas DSM Tariff Rider, Schedule 191, was reduced to $0 until the avoided costs increased and natural gas programs could again be offered. In 2001 Schedule 191 rider amount was increased and natural gas DSM programs were again implemented. The Company has had uninterrupted natural gas DSM since 2001.

CPA METHODOLOGY

Prior to the development of potential estimates, Global developed a baseline end-use forecast to quantify the use of natural gas by end use, in the base year, and projections of consumption in the future in the absence of utility programs and naturally occurring conservation. The end-use forecast includes the relatively certain impacts of codes and standards that will unfold over the study timeframe. All such mandates that were defined as of January 2011 are included in the baseline. The baseline forecast is the foundation for the analysis of savings from future DSM efforts, as well as, the metric against which potential savings are measured.

Inputs to the baseline forecast include current economic growth forecasts (e.g. customer growth, income growth), natural gas price forecasts, trends in fuel shares and equipment saturations developed by Global, existing and approved changes to building codes and equipment standards, and Avista's internally developed sales forecasts.

According to the natural gas CPA completed for Avista, the residential sector natural gas consumption for all end uses and technologies increases, mainly due to the projected 1.7 percent annual growth in the number of households, but also due to the slight increase in the average home size. Other heating, which includes unit wall heaters and miscellaneous loads, have a relatively high growth rate compared to other loads. However, at the end of the 20-year planning period, these loads represent only a small part of overall use.

For the commercial and industrial (C&I) sectors, natural gas use continues to grow slowly over the 20-year planning horizon as new C&I construction increases the overall square footage in the commercial sector. In addition, existing buildings are renovated to incorporate additional amenities such as full-scale kitchens. Growth in the HVAC and water heating end uses is moderate. Food preparation, though a small percentage of total usage, grows at a higher rate than other end uses. Consumption by miscellaneous equipment and process heating are also projected to increase.

Table 4.1 illustrates the system-wide baseline forecast and how natural gas use across all sectors is expected to increase by 28 percent during the 20-year planning horizon, for an average annual growth of 1.1 percent. Overall, the forecast for the next 20 years grows steadily, dominated by growth in the residential sector. Further, growth is forecasted to be highest in Idaho followed by Oregon.

Table 4.1 Baseline Forecast Summary (1000 therms*)*

Sector	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Residential	188,894	196,073	197,449	204,112	219,778	241,292	269,274	43%	**1.5%**
Sm. Commercial	50,693	50,130	50,530	51,271	52,378	53,494	55,120	9%	**0.4%**
Lg. Commercial	71,176	69,274	69,647	70,392	71,667	73,191	75,295	6%	**0.2%**
Industrial	5,141	5,026	5,067	5,156	5,274	5,409	5,560	8%	**0.3%**
Total	**315,906**	**320,503**	**322,693**	**330,932**	**349,097**	**373,385**	**405,250**	**28%**	**1.1%**

State	2010	2013	2014	2017	2022	2027	2032	% Change (2010-2032)	Avg. Growth Rate (2010-2032)
Washington	167,021	168,616	169,523	173,064	180,908	191,260	205,302	23%	**0.9%**
Idaho	72,017	73,767	74,426	76,910	82,427	89,742	99,277	38%	**1.4%**
Oregon	76,867	78,120	78,744	80,958	85,762	92,383	100,671	31%	**1.2%**
Total	**315,906**	**320,503**	**322,693**	**330,932**	**349,097**	**373,385**	**405,250**	**28%**	**1.1%**

The next step in the study is the development of the three types of potential: technical, economic and achievable. Technical potential is the theoretical upper limit of conservation potential. This assumes that all customers replace equipment with the most efficient option available regardless of cost, as well as, the adoption of every available non-equipment measure, where applicable. Economic potential represents the adoption of cost-effective conservation measures based on the Total Resource Cost (TRC) test and assumes that customers purchase the most cost-effective and applicable measure. Finally, achievable potential takes into account market maturity, customer preferences for energy efficiency technologies and expected program participation. Achievable potential establishes a realistic target for conservation savings that a utility can expect to achieve through its programs.

DSM measures that achieve generally uniform year round energy savings, independent of weather are considered base load measures. Examples include high efficiency water heaters, cooking equipment and front load clothes washers. Weather sensitive measures are those which are influenced by heating degree day factors and include higher efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, duct work improvements (tighter sealing to reduce leaks) and ventilation heat recovery systems (capturing chimney heat). Weather sensitive measures are desirable in resource planning, as they save the most energy during the coldest periods, thus displacing the more expensive peaking or seasonal supply resources. Weather sensitive measures are often referred to as “winter measures” and are typically valued using a higher avoided cost (due to summer to winter pricing differentials) while base load measures often called “annual measures” are valued at a lower avoided cost.

Conservation measures are offered to residential, non-residential and low-income[2] customers. Conservation measures offered to residential customers are classified as prescriptive, meaning they have a standardized therm savings which can be generalized across the customer class and all customers receive the same financial incentive for the same measures. Low income customers receive a more holistic, customized approach through

[2] For purposes of tables, figures and targets, low income is a subset of residential class.

a handful of Community Action Agency partnerships. Non-residential customers have access to prescriptive and site-specific conservation measures. Site-specific measures are customized to the facility and have cost and therm savings that are unique to the individual facility.

Finally, some conservation measures in Oregon are required by law and are therefore designated “mandatory” or “must take” measures in the modeling tool, which means they are offered to customers without regard to their current cost-effectiveness relative to the utility’s supply resources. An example of a mandated measure is a walk-through energy audit, which would not be accompanied by energy savings unless a customer chooses to participate in a program. In addition, a customer may choose to delay participating in a program for many years. In these cases, the audit would be non-cost effective since there is no savings benefit to offset the cost of the audit.

See Table 4.2 for Residential and C&I Measures evaluated in this study for all three states.

Table 4.2 Conservation Measures

Residential Measures	C&I Measures
Furnace – Maintenance	Furnace – Maintenance
Boiler – Pipe Insulation	Boiler – Maintenance
Insulation – Ducting	Boiler – Hot Water Reset
Insulation – Infiltration Control	Boiler – High Efficiency Hot Water Circulation
Insulation – Ceiling	Space Heating – Heat Recovery Ventilator
Insulation – Wall Cavity	Insulation – Ducting
Insulation – Attic Hatch	Insulation – Ceiling
Insulation – Foundation (new only)	Insulation – Wall Cavity
Ducting – Repair and Sealing	Ducting – Repair and Sealing
Doors – Storm and Thermal	Windows – High Efficiency
Windows – ENERGY STAR	Energy Management System
Thermostat – Clock/Programmable	Thermostat – Clock/Programmable
Water Heating – Faucet Aerators	Water Heating – Faucet Aerators
Water Heating – Low Flow Showerheads	Water Heating – Pipe Insulation
Water Heating – Pipe Insulation	Water Heating – Tank Blanket/Insulation
Water Heating – Tank Blanket/Insulation	Water Heating – Hot Water Saver
Water Heating – Thermostat Setback	Advanced New Construction Designs (new only)
Water Heating – Timer	Comprehensive Commissioning
Water Heating – Hot Water Saver	Process – Boiler Hot Water Reset (industrial only)
Water Heating – Drain Water Heat Recovery (new only)	
Home Energy Management System	
Advanced new Construction Designs (new only)	
ENERGY STAR Homes (new only)	

POTENTIAL RESULTS

The technical potential reflects the adoption of all DSM measures regardless of cost effectiveness and represents the upper limit on savings. Over the 20 years considered by the CPA, technical potential reaches 38.9 percent of the baseline end-use forecast.

Economic potential applies the TRC test to measures identified within the technical potential and reflect the adoption of DSM measures that are cost-effective. By the end of the 20-year timeframe this represents 14.6 percent of the baseline energy forecast. The significant difference between the technical and economic potential reflects the lower natural gas avoided costs resulting from shale gas, as well as, the influence of

Avista's long-running history of operating DSM programs that have already achieved much of the cost-effective conservation. Consequently, the remaining conservation measures are becoming incrementally more expensive on a per-therm basis and many, therefore, do not pass the cost-effectiveness screen based on current avoided costs.

Finally, achievable potential across the residential, commercial and industrial sectors is 12.9 percent of the baseline energy forecast by the end of 2032.

For the Oregon service territory, it should be noted that both economic and achievable potential include residential weatherization measures that are mandated by Oregon legislation to be provided regardless of cost effectiveness and other factors. Many of these measures did not pass the TRC benefit-cost ratio analysis but were nevertheless included in economic and achievable potential.

Tables 4.3 and 4.4 summarize cumulative conservation for each potential type for selected years across the 20-year CPA and IRP horizon. Initially, the large commercial sector provides a relatively higher percentage of the achievable savings compared with its share of sales, but over time, this situation reverses so that the residential sector's share of savings is the greatest, due to growth in residential customer count. For more specific detail, please refer to the natural gas CPA provided in Appendix 4.1.

Table 4.3 Summary of Cumulative Achievable, Economic and Technical Conservation Potential

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
	320,503	322,693	330,932	349,097	373,385	405,250
Cumulative Natural Gas Savings (1000 thm)						
Achievable	1,546	3,738	12,794	28,216	41,349	52,381
Economic	1,797	4,333	14,785	31,757	45,809	58,965
Technical	7,623	15,844	46,189	91,655	131,422	157,520
Cumulative Natural Gas Savings (% of Baseline)						
Achievable	0.5%	1.2%	3.9%	8.1%	11.1%	12.9%
Economic	0.6%	1.3%	4.5%	9.1%	12.3%	14.6%
Technical	2.4%	4.9%	14.0%	26.3%	35.2%	38.9%

Furthermore, overall potential is presented first by state and then for each sector in the following table.

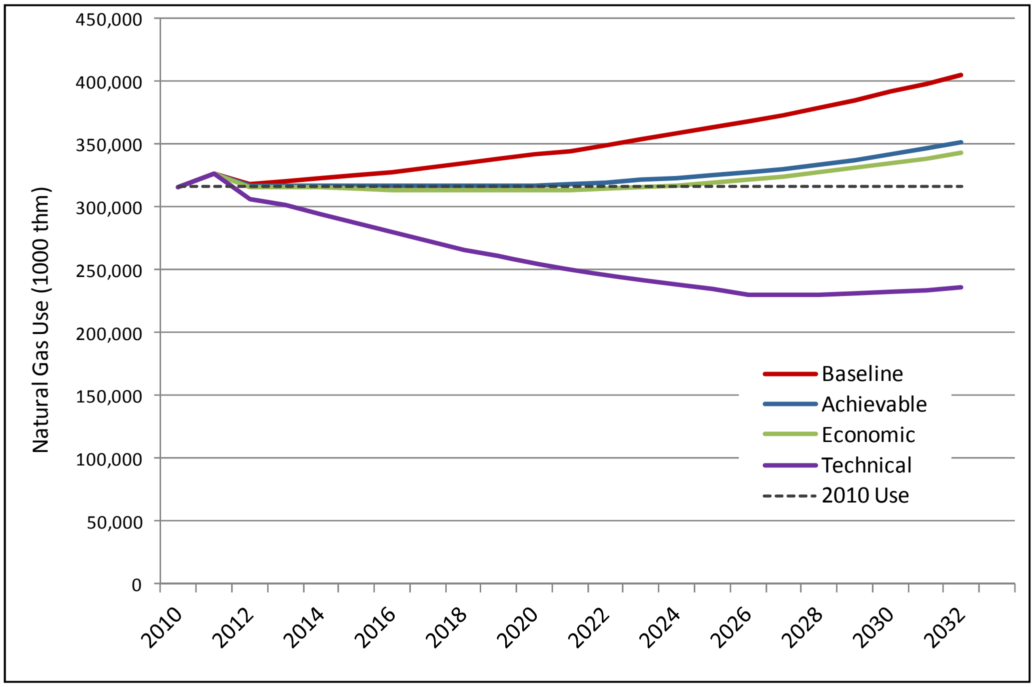
Table 4.4 Summary of Cumulative Achievable, Economic and Technical Conservation Potential by State and Sector

Cumulative Savings (1000 them)	2013	2014	2017	2022	2027	2032
Washington	893	2,203	6,923	15,364	21,885	26,909
Idaho	364	821	2,734	5,601	8,758	11,914
Oregon	289	715	3,136	7,251	10,706	13,559
Total	**1,546**	**3,738**	**12,794**	**28,216**	**41,349**	**52,381**

Cumulative Savings (1000 them)	2013	2014	2017	2022	2027	2032
Residential	515	1,567	6,507	14,903	22,278	29,960
Small Commercial	206	469	1,588	3,557	5,709	7,018
Large Commercial	801	1,654	4,548	9,436	13,007	15,027
Industrial	25	49	151	319	354	377
Total	**1,546**	**3,738**	**12,794**	**28,216**	**41,349**	**52,381**

Figure 4.1 below illustrates the potential forecasts compared with the end-use baseline forecast that was projected to occur in the absence of utility DSM programs. The dotted black line depicts the 2010 usage level. By the end of the 20-year period, achievable potential (indicated by the blue line) offsets 60 percent of the growth in the baseline forecast.

Figure 4.1 - Conservation
Potential Energy Forecast (1000 therm)



POTENTIAL RESULTS – RESIDENTIAL

Single-family homes represent 79 percent of Avista's residential natural gas customers, but accounts for 84 percent of the sector's consumption in the study base year 2010. While Oregon represents only about one-quarter of the baseline forecast, it makes up between 28 and 35 percent of the achievable potential savings. This is due to the inclusion of the legislatively mandated weatherization and insulation measures within Oregon's achievable potential.

Table 4.5 provides a distribution of achievable potential by state for the residential sector.

Table 4.5 Residential Cumulative Achievable Potential by State, Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
Washington	100,894	101,415	104,274	110,964	119,962	132,043
Idaho	46,065	46,424	48,209	52,647	58,832	67,038
Oregon	49,114	49,609	51,629	56,167	62,498	70,193
Total	**196,073**	**197,449**	**204,112**	**219,778**	**241,292**	**269,274**
Natural Gas Savings (1000 thm)						
Washington	237	838	3,017	7,268	10,634	13,894
Idaho	121	306	1,248	2,337	4,002	6,246
Oregon	156	422	2,242	5,298	7,642	9,819
Total	**515**	**1,567**	**6,507**	**14,903**	**22,278**	**29,960**
% of Total Residential Savings						
Washington	46.2%	53.5%	46.4%	48.8%	47.7%	46.4%
Idaho	23.6%	19.6%	19.2%	15.7%	18.0%	20.8%
Oregon	30.3%	26.9%	34.5%	35.5%	34.3%	32.8%

The bulk of the residential potential exists primarily with space heating followed by water heating applications. Appliances and miscellaneous contribute a small percentage of potential. Based on measure-by-measure finding of the potential study, the greatest sources of residential achievable potential across all three states are:

- Shell measures and insulation
- Thermostats and home energy monitoring systems
- Water-saving devices such as low-flow showerheads and faucet aerators
- Water heater tank blankets and pipe insulation

POTENTIAL RESULTS – COMMERCIAL AND INDUSTRIAL

The baseline forecast for the C&I sector grows steadily during the forecast period as the region begins to recover from the economic downturn. Consequently, energy efficiency opportunities are significant for this sector. However, similar to the residential sector, many conservation opportunities do not pass the TRC economic screen given the low natural gas avoided costs.

The large commercial sector provides the greatest opportunities for savings. Although potential as a percentage of baseline use varies from one sector to the next, results do not vary greatly among the three states. See Table 4.6 for achievable potential by sector for selected years.

Table 4.6 C&I Cumulative Achievable Potential by Selected Years

	2013	2014	2017	2022	2027	2032
Baseline Forecast (1000 thm)						
Small Commercial	50,130	50,530	51,271	52,378	53,494	55,120
Large Commercial	69,274	69,467	70,392	71,667	73,191	75,295
Industrial	5,026	5,067	5,156	5,274	5,409	5,560
Total	**124,429**	**125,244**	**126,819**	**129,319**	**132,094**	**135,976**
Natural Gas Savings (1000 thm)						
Small Commercial	206	469	1,588	3,557	5,709	7,018
Large Commercial	801	1,654	4,548	9,436	13,007	15,027
Industrial	25	49	151	319	354	377
Total	**1,031**	**2,172**	**6,287**	**13,312**	**19,071**	**22,422**
% of Total C&I Savings						
Small Commercial	20.0%	21.6%	25.3%	26.7%	29.9%	31.3%
Large Commercial	77.6%	76.2%	72.3%	70.9%	68.2%	67.0%
Industrial	2.4%	2.2%	2.4%	2.4%	1.9%	1.7%

Similar to Residential, the bulk of the C&I potential exists within space heating and water heating applications. Food preparation, process and miscellaneous represents a smaller proportion of potential. Primary sources of commercial achievable savings are:

- Energy management systems and programmable thermostats
- Boiler operating measures such as maintenance
- Hot water reset and efficient circulation
- Equipment upgrades for furnaces, boilers and unit heaters
- Food service equipment

SENDOUT® MODELING METHODOLOGY

The SENDOUT® model understands that investments made in DSM are a long-term resource decision. The model also understands that some programs may not be cost-effective in the initial forecast years; however the total cost over the life of the measure, coupled with the cumulative therms savings, is economic. Due to this modeling nuance, SENDOUT® typically selects most of the DSM potential.

While the IRP process evaluates demand-side and supply-side resources for a 20-year planning horizon, the process also results in a starting point for the two year operational business plan and goal for natural gas DSM. The business plan sets targets specific to each state and sector – residential and C&I. The following three tables provide the 2013-2014 CPA identified DSM opportunity for Idaho, Oregon and Washington, respectively.

Table 4.7 Idaho Natural Gas Target (2013-2014)

Incremental Annual Savings (1000 therm)	2013	2014
Residential	121	185
Commercial & Industrial	246	271
Total	**364**	**456**

Table 4.8 Oregon Natural Gas Target (2013-2014)

Incremental Annual Savings (1000 therm)	2013	2014
Residential	156	266
Commercial & Industrial	133	160
Total	**289**	**426**

Table 4.9 Washington Natural Gas Target (2013-2014)

Incremental Annual Savings (1000 therm)	2013	2014
Residential	237	601
Commercial & Industrial	655	709
Total	**893**	**1,310**

There are substantial methodological differences between the Global Energy Partners CPA and Avista's operational business planning process. These include how measures are aggregated into programs offerings and evaluated, how non-incentive infrastructure costs are treated, and how specific the results are to Avista's service territory and program offerings. The CPA provides substantial guidance in evaluating the entire spectrum of efficiency options and illustrating trends in equipment and technologies, however the business planning process is a reflection of the likely results of actual DSM operations.

Key analytical differences between the CPA and the business planning process include the 'splintering' of measures into numerous scenarios (by building type, replace-before-burnout vs. replace-on-burnout, by jurisdiction, etc.). These splintered measures may pass and generate the expectation of the cost-effective acquisition of resources, but if the measures are not collectively cost-effective when aggregated into a program that can be operationally delivered, there are no realistic prospects for achieving these projections. Additionally there are differences in non-incentive utility cost levels driven by program design approaches and how these costs are distributed. Fundamentally these differences are driven by the use of an independent third-party packaged model intended to provide general guidance regarding resource acquisition economics versus a utility-specific business planning approach incorporating operational details, program-specific assumptions and indexed to past actual results. These differences can lead to different results under many conditions, especially under challenging cost-effectiveness scenarios.

THE BUSINESS PLANNING PROCESS AND CONSERVATION GOALS

Each fall, Avista develops a DSM business plan where CPA-identified measure applications are re-cast into operational DSM programs and goals are developed. For example, a CPA could identify that 3-pan and 5-pan commercial cookware would be cost-effective while 4-pans may not. However, programmatically, since the 4-pan cookware is such a small slice of the market, the program would ultimately incent all of these non-residential cookware options. As explained above, the 'splintered' approach utilized in the evaluation of natural gas efficiency options within the CPA can lead to substantially different results than can be operationally achieved. Under those circumstances Avista has found that the business planning process is more indicative of what is operationally achievable.

Evaluation of the Washington/Idaho natural gas portfolio using these latest avoided costs have not resulted in any scenarios where Washington/Idaho natural gas programs are cost-effective, on either a gross or net basis. Consequently, Avista has filed in both states for an indefinite suspension of its Washington/Idaho natural gas DSM programs.

The Company has history of suspending natural gas DSM when avoided costs have decreased rendering programs cost-ineffective. Since Washington and Idaho electric DSM portfolio continues to be cost-effective and operate, it is fairly easy for the Company to ramp up the natural gas programs again should there be a change in the natural gas avoided costs. Avista's natural gas DSM programs were suspended in 1997 due to decreased avoided costs and were reinstated when avoided costs increased three years later. The Company will continue to monitor Weighted Average Cost of Gas (WACOG) as a proxy to determine changes in avoided costs.

The Oregon natural gas DSM portfolio is undergoing portfolio evaluation. This evaluation will incorporate the continuation of mandated audit services, as well as, any programs which can be redesigned to meet the required criteria. Additional review of appropriate methodologies will occur to include discussions of the appropriate discount rate and base case. This work is being expedited in recognition of the need to implement program redesigns or suspensions in a responsible manner and timeline.

While the lower natural gas avoided costs can be viewed as disappointing news for DSM, the good news for customers translates to lower retail rates. In addition, some electric efficiency programs such as fuel conversions become even more cost-effective and there may be potential for increases in customer incentives to enhance participation in these programs and encourage customers to make the appropriate fuel choice. Avista continues to support energy efficiency efforts where cost-effectiveness allows.

ENVIRONMENTAL EXTERNALITIES

The impact of utilizing energy on the environment continues to be a subject of societal concern and debate. If there are impacts that cannot be repaired naturally within a reasonable period of time, damage cost to the environment occurs for which society will have to pay in some future undetermined form. The question of who pays, how much and when payment should be made, are complicated issues. This longstanding debate is trying to be addressed through a variety of public policy initiatives and legislation. Regulatory guidelines in Oregon[3] advocate specific analysis in the IRP process to better understand these issues. Avista included an evaluation of the impacts of environmental externalities in the context of this evolving legislative environment. Appendix 4.2 discusses the analysis.

DEMAND RESPONSE

Demand response is a peak demand management concept where customers adjust the timing of their energy consumption away from consumption peaks in exchange for lower rates. Implementation strategies encompass a number of activities including real-time pricing, time- of-use rates, critical- peak pricing, demand buyback, interruptible rates and direct-load controls. When effectively implemented, acquisition of costly supply resources can be deferred.

Demand response works best when it is a quick solution to an immediate problem. When demand peaks, system operators need the ability to either quickly notify customers to curtail consumption or do it themselves via control systems to physically manage/restrict gas flow to increase distribution system pressures.

This mechanism exists with respect to our interruptible transportation-only customers, which make up approximately one third of Avista's total annual throughput. However, because we do not purchase supply for these customers, they do not represent an incremental supply resource alternative. Only core customers with high winter consumption profiles would provide an incremental supply resource using demand response curtailment strategies. Unfortunately, we currently have very few core customers with a complying consumption profile. As a result, we believe that all customers who can manage their operations on interruptible service are currently served on an interruptible basis, leaving little opportunity to reduce peak loads through expanded interruptible service.

While little demand response opportunity exists on our natural gas system, we continue to monitor the progress of other natural gas utilities and their efforts of peak load shifting to offset hourly and/or daily flow constraints. Whereas electric demand response technologies have been in place for over two decades, major differences exist between electric and natural gas supply/delivery systems. The economics of the timing of natural gas usage are much more forgiving than electric due to underground storage and line packing. Furthermore, natural gas curtailment is not an option since a natural gas company cannot restart service without a technician on-site to ensure all pilots are properly lit for safety reasons.

At times natural gas providers may find implementing a demand response program helpful in offsetting or postponing a pipeline upgrade or in price balancing. However, mandatory participation in the affected areas would be vital to fund the necessary investment in enabling technologies.

‖ CONCLUSION

By encouraging customers to change their demand for natural gas, Avista can displace the need to purchase additional natural gas supplies, displace or delay contracting for incremental pipeline capacity and possibly displace or delay the need for upgrades to our distribution system. This IRP process provides the utility with the necessary resource analysis to evaluate demand-side resource options on par with supply-side resources,

[3] Oregon IRP regulations require that a 10% cost advantage accrues to DSM resources relative to supply resources for environmental externalities costs. Appendix 4 describes our analysis.

periodically review and update DSM operations and finally, develop and implement improved natural gas energy efficiency programs.

The completion of the IRP analysis is not the end point, but rather the midpoint of a much larger evaluation of the DSM natural gas resource portfolio. The IRP analysis presented has generally indicated a conservation potential for a future DSM program design and delivery. However, differences in modeling methodologies require further evaluation through Avista's annual business planning process in order to facilitate the development of a cost-effective program portfolio to be incorporated into overall DSM operations.

Even though applications to suspend gas DSM have been filed, Avista is committed to closely monitoring proxies for the natural gas avoided cost and returning the natural gas DSM programs to our menu of offerings if commodity costs and efficiency technologies or program delivery options change in such a manner as to make these programs cost-effective under the Total Resource Cost test. This monitoring will be performed on an ongoing basis in addition to our regularly scheduled annual DSM business plans and the biennial IRP process.

CHAPTER 5 ‖ SUPPLY-SIDE RESOURCES

OVERVIEW

We have analyzed a range of anticipated future demand scenarios and a variety of possible conservation measures to reduce demand. This chapter discusses possible supply options to meet net demand. Our objective is to reliably provide natural gas to customers with an appropriate balance of price stability and prudent cost while navigating continuously changing market conditions. To achieve this, we evaluate a variety of supply-side resources and attempt to build a supply portfolio that is appropriately diversified. The resource acquisition and commodity procurement programs resulting from our evaluation consider physical and financial risks, market-related risks and procurement execution risks and identify the methods we deploy to mitigate these risks.

We manage our natural gas procurement and related activities on a system-wide basis. We have a number of regional supply options available to serve our core customers. These include firm and non-firm supplies, firm and interruptible transportation on six interstate pipelines and storage. Because Avista's core customers span three states, the diversity of delivery points and demand requirements adds to the options available to meet customers' needs. The utilization of these components varies depending on demand and operating conditions. In this chapter, we discuss the available regional commodity resources and our procurement plan strategies, the regional pipeline resource options available to deliver the commodity to our customers, and the storage resource options available which provide additional supply diversity, enhanced reliability, favorable price opportunities and flexibility to meet a varied demand profile. Beyond these traditional supply-side resources we discuss non-traditional resources which are also considered.

COMMODITY RESOURCES

SUPPLY BASINS

Avista is fortunate to be located in relatively close proximity to the two largest natural gas producing regions in North America – the Western Canadian Sedimentary Basin (WCSB), which is located primarily in the Canadian provinces of Alberta and British Columbia, and the Rocky Mountain (Rockies) gas basin, located primarily in Wyoming, Utah and Colorado. Avista sources virtually all of its natural gas supplies from these two basins.

The WCSB and Rockies gas basins used to have limited pipeline export potential, which has historically resulted in lower regional natural gas prices when compared to other parts of the country. Over the last decade, however, several large pipelines have been completed (or capacities of existing pipelines increased) connecting the WCSB and Rockies gas basins to the Southwest, Midwest and Northeast sections of the continent. This has at times diminished the discounted price advantage the Region has enjoyed. Furthermore, the prolific amounts of shale gas located across North America (particularly in the East) have and will continue to change the flow dynamics. Forecasts show a continued price advantage for the region in both the WCSB and Rockies basins as the need for these supplies to move East diminishes.

Increased availability of North American natural gas has prompted a change in the LNG landscape. More supply than demand has changed the plans of many LNG import facilities. Now owners of these facilities are looking to switch from importing to exporting gas in order to capture better pricing in the Asian and European markets. Regionally, Kitimat LNG has received authorization to export natural gas off the coast of British Columbia. Two proposed import LNG facilities in Oregon have petitioned FERC to become export facilities. While there is much uncertainty about how many facilities actually get built the bigger question is how regional markets will be impacted by potential exports.

REGIONAL MARKET HUBS

Extending out from the two primary basins are numerous regional market hubs where natural gas is traded. These typically are located at pipeline interconnects. Avista is located near and transacts at most of the Pacific Northwest regional market hubs, enabling flexible access to a diversity of supply points. These supply points include:

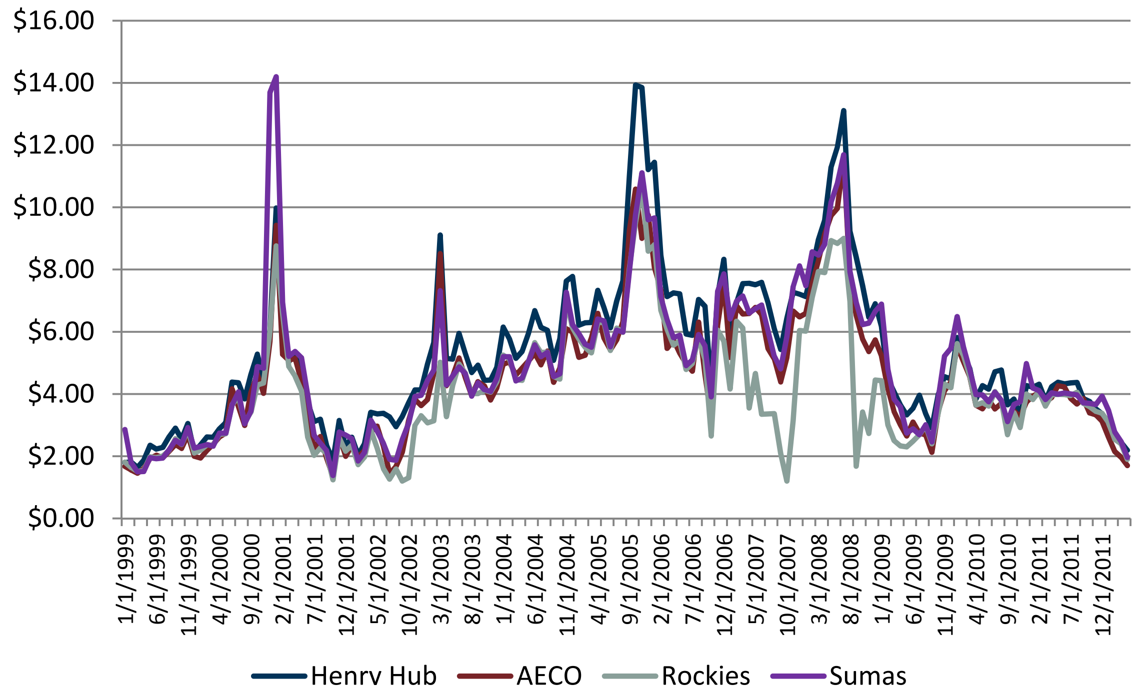
- **AECO –** The AECO-C/Nova Inventory Transfer market center is a major connection region to long-distance transportation systems, which take gas to points throughout Canada and the United States. Alberta has historically produced 90% of Canada's natural gas and is the source of most Canadian natural gas exports to the U.S. representing volume that accounts for approximately 13% of U.S. natural gas requirements.
- **ROCKIES** – This pricing "point" actually represents several locations on the southern end of the NWP system in the Rocky Mountain region. The system draws on Rocky Mountain gas-producing areas clustered in areas of Colorado, Utah, and Wyoming.
- **SUMAS/HUNTINGDON** – This pricing point at Sumas, Wash., is on the U.S./Canadian border where the northern end of the NWP system connects with Spectra Energy's Westcoast Pipeline, and is predominantly Canadian gas coming south from Northern British Columbia.
- **MALIN** – this pricing point is at Malin, Ore. on the California/Oregon border where the pipelines of TransCanada Gas Transmission Northwest (GTN) and Pacific Gas & Electric Co. connect.
- **STATION 2** – Located at the center of the Spectra Energy/Westcoast Pipeline system connecting to northern British Columbia production.
- **STANFIELD** – Located near the Washington/Oregon border at the intersection of the NWP and GTN pipelines
- **KINGSGATE** – Located at the U.S./Canadian (Idaho) border where the GTN pipeline connects with the TransCanada Foothills pipeline.

Given the ability to transport natural gas to other portions of North America natural gas pricing is often compared to the Henry Hub price for natural gas. Henry Hub is a natural gas trading point located in Louisiana is widely recognized as the primary natural gas pricing point in the U.S. and is also the trading point used in NYMEX futures contracts.

Figure 5.1 shows historic natural gas prices for first-of-month index physical purchases at AECO, Sumas, Rockies and Henry Hub. The figure illustrates there is usually a tight relationship among the various locations; however, there have been periods where one or more price points have disconnected. In winter 2000-2001 Sumas rallied on a combination of the Western energy crisis and unusually cold local weather conditions. In fall of 2005 hurricanes Katrina and Rita disrupted significant Gulf of Mexico regional production causing the Henry Hub to spike disproportionately to Northwest hubs. Since 2007 increased production in the Rocky Mountain basin has exceeded the takeaway pipeline capacity forcing concessions on Rockies prices pending completion of major phases of the Rockies Express pipeline project. This significant project – completed in late summer 2009 – enables substantial volumes to reach Midwestern and

Northeastern demand centers. Consequently, Rockies prices have resumed tighter tracking with Henry Hub prices. As prices have declined the pricing differentials among the basins have tightened.

Figure 5.1 - Monthly Index Prices



Natural gas prices among the Northwest regional supply points typically move together as well; however, the basis differential can change depending on market or operational factors. This includes differences in weather patterns, pipeline constraints at different locations and the ability to shift supplies to higher-priced delivery points in the U.S. or Canada. By monitoring these price shifts we are often able to purchase at the lowest-priced trading hubs on a given day, subject to operational and contractual constraints.

Liquidity is generally sufficient in the day-markets at most northwest supply points. AECO continues to be the most liquid supply point, especially for longer-term transactions. Sumas has historically been the least liquid of the four major supply points (AECO, Rockies, Sumas, Malin). This illiquidity contributes to generally higher relative prices in the high demand winter months.

Procurement of natural gas is done via contracts. There are a number of contract specifics that vary from transaction-to-transaction, and many of those terms or conditions impact commodity pricing. Some of the agreed-upon terms and conditions include:

- **Firm vs. Non-Firm** – Most term contracts specify that supplies are firm except for force majeure conditions. In the case of non-firm supplies the standard provision is that they may be cut for reasons other than force majeure conditions.
- **Fixed vs. Floating Pricing** – The agreed-upon price for the delivered gas may be fixed or based upon a daily or monthly index.
- **Physical vs. Financial** – Certain counterparties, such as banking institutions, may not trade physical natural gas but are still active in the natural gas markets. Rather than managing physical

supplies, those counterparties choose to transact financially rather than physically. Financial transactions provide another way for Avista to financially hedge price.

- **LOAD FACTOR/VARIABLE TAKE** – Some contracts have fixed reservation charges assessed during each of the winter months, while others have minimum daily or monthly take requirements. Depending on the specific provisions, the resulting commodity price will contain a discount or premium compared to standard terms.
- **LIQUIDATED DAMAGES** – Most contracts contain provisions for symmetrical penalties for failure to take or supply natural gas.

For this IRP, the SENDOUT® model assumes the natural gas is purchased as a firm, physical, fixed-price contract regardless of when the contract is executed and what type of contract it is. However, in reality, we pursue a variety of contractual terms and conditions in order to capture the most value from each transaction.

AVISTA'S PROCUREMENT PLAN

We cannot accurately predict future natural gas prices but market conditions and experience help shape our overall approach. Avista has designed a natural gas procurement plan process that seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility. Our procurement strategy includes hedging, storage utilization and index purchases. Although the specific provisions of the procurement plan will change as a result of ongoing analysis and experience, the following principles guide Avista's development of its procurement plan:

Avista employs a time, location and counterparty diversified hedging strategy. It is appropriate to hedge over a period of time and we establish hedge periods within which portions of future demand are physically and/or financially hedged. The hedges may not be completed at the lowest possible price but they will protect our customers from price volatility. With access to multiple supply basins, when we transact we seek the lowest priced basin. Furthermore, we transact with a range of counterparties.

Avista establishes a disciplined but flexible hedging approach. In addition to establishing hedge periods within which hedges are to be completed we also set upper and lower pricing points. In a rising market this reduces Avista's exposure to extreme price spikes. In a declining market this encourages capturing the benefit associated with lower prices.

Avista regularly reviews its procurement plan in light of changing market conditions and opportunities. Avista's plan is open to change in response to ongoing review of the assumptions that led to the procurement plan. Although we establish various targets in the initial plan design, policies provide flexibility to exercise judgment to revise/adjust targets in response to changing conditions.

A number of tools are utilized to help mitigate financial risks. Avista purchases gas in the spot market as well as the forward market. Spot purchases are made on a day for the next day or weekend. Forward purchases are made on a day for a designated future delivery period. Many of these tools are financial instruments or derivatives that can be utilized to provide fixed prices or dampen price volatility. We continue to evaluate how to manage daily demand volatility, whether through option tools available from counterparties or through access to additional storage capacity and/or transportation.

TRANSPORTATION RESOURCES

Although proximity to the liquid hubs is important from a cost perspective those supplies are only as reliable or firm as the pipeline transportation from the hubs to Avista's service territories. Capturing favorable price differentials and mitigating price and operational risk can also be realized by holding multiple pipeline transport options. Consequently, we have contracted for a sufficient amount of diversified firm pipeline capacity from various receipt and delivery points (including out of storage facilities) so that firm deliveries will meet peak day demand. We believe the combination of firm transportation rights to our service territory, storage facilities and access to liquid supply basins will ensure peak supplies are available to our core customers.

The major pipelines servicing our region are as follows:

- **WILLIAMS - NORTHWEST PIPELINE (NWP)**
  A natural gas transmission pipeline serving the Pacific Northwest moving natural gas from the US/Canadian border in Washington and from the Rocky Mtn. region of the US.
- **TRANSCANADA GAS TRANSMISSION NORTHWEST (GTN)**
  A natural gas transmission pipeline originating at Kingsgate, Idaho (Canadian/U.S. border) and terminating at the California/Oregon border close to Malin, Ore.
- **TRANSCANADA ALBERTA SYSTEM**
  A natural gas gathering and transmission pipeline in Alberta Canada that delivers natural gas into the TransCanada Foothills pipeline at the Alberta/British Columbia border.
- **TRANSCANADA FOOTHILLS SYSTEM**
  A natural gas transmission pipeline that delivers natural gas between the Alberta, British Columbia border and the Canadian/U.S. border at Kingsgate, Idaho.
- **TRANSCANADA TUSCARORA GAS TRANSMISSION**
  A natural gas transmission pipeline originating at Malin, Ore and terminating at Wadsworth, Nev.
- **SPECTRA ENERGY - WESTCOAST PIPELINE**
  A natural gas transmission pipeline originating at Fort Nelson, British Columbia and terminating at the Canadian/U.S. border at Huntington, British Columbia/Sumas, Wash.
- **EL PASO NATURAL GAS– RUBY PIPELINE**
  A natural gas transmission pipeline bringing supplies from the Rocky Mountain region of the U.S. to interconnections near Malin, Ore. Ruby Pipeline began operating in July 2011.

Avista has contracts with all of the above pipelines (with the exception of Ruby Pipeline) for firm transportation to serve our core customers. Table 5.1 details the firm transportation/resource services contracted by Avista. These contracts are of different vintages, thus different expiration dates; however, all have the right to be renewed by Avista. This gives Avista and its customers the knowledge that Avista will have available capacity to meet existing core demand now and in the future.

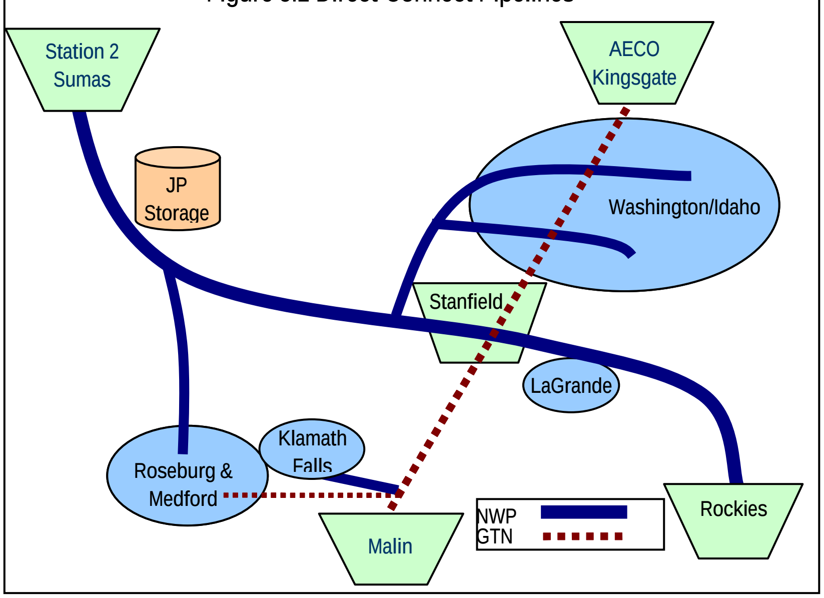
Table 5.1
Firm Transportation/Resources Contracted*
Dth/Day

	Avista North		Avista South	
Firm Transportation	**Winter**	**Summer**	**Winter**	**Summer**
NWP TF-1	157,869	157,869	42,699	42,699
GTN T-1	100,605	75,782	42,260	20,640
NWP TF-2	91,200		2,623	
Total	**349,674**	**233,651**	**87,582**	**63,339**
Firm Storage Resources - Max Deliverability				
Jackson Prairie (Owned and Contracted)	346,667		54,623	
Total	**346,667**		**54,623**	

** Represents original contract amounts after releases expire.*

Avista defines two categories of interstate pipeline capacity. “Direct-connect” pipelines deliver supplies directly to our local distribution system from production areas, storage facilities or interconnections with other pipelines. “Upstream” pipelines deliver natural gas to the direct-connect pipelines from remote production areas, market centers and out of area storage facilities. Figure 5.2 illustrates the direct-connect pipeline network relative to our supply sources and service territories1.

Figure 5.2 Direct-Connect Pipelines



1 Avista has a small amount of pipeline capacity with TransCanada Tuscarora Gas Transmission, a natural gas transmission pipeline originating at Malin, Oregon, to service a small number of Oregon customers near the southern border of the state.

Supply-side resource decisions focus on where to purchase natural gas and how to deliver it to customers. Each LDC has distinctive service territories and geography relative to supply sources and pipeline infrastructure. Solutions that deliver supply to service territories among regional LDCs are similar but are rarely generic – instead they are almost always unique.

The NWP system for the most part is a fully contracted system. With the exception of La Grande our service territories lie at the end of various NWP pipeline laterals. Washington/Idaho is served via the Spokane, Coeur d' Alene and Lewiston laterals while Roseburg and Medford are served by the Grants Pass lateral. Capacity expansions on each of these laterals are lengthy and costly endeavors which Avista would likely bear most of the incremental costs.

The GTN system, on the other hand, currently has ample unsubscribed capacity. This pipeline runs directly through or lies in close proximity to most of our service territories. Mileage based rates and backhaul potential provide attractive options for securing incremental resource needs.

Peak day planning aside, both pipelines provide an array of options to flexibly manage daily operations. Our two largest service territories are directly served by both pipelines providing diversification and risk management with respect to supply source, price and reliability. The NWP system (a bi-directional, fixed reservation fee-based pipeline) provides direct access to Rockies and British Columbian supply and facilitates excellent optionality for storage facility management. The Stanfield interconnect of the two lines is also geographically well situated to our service territories.

The rates we use in our planning model start with filed rates that are currently in effect (See Appendix 5.1). Forecasting future pipeline rates is challenging. Our assumptions for future rate changes are the result of market information on comparable pipeline projects, prior rate case experience and informal discussions. It is generally assumed that the pipelines will file to recover costs at rates equal to the GDP with adjustments made for specific project conditions.

NWP and GTN also offer interruptible transportation services. The level of service of interruptible transportation is subject to curtailment when pipeline capacity constraints limit the amount of natural gas that may be moved. Although the commodity cost per dekatherm transported is the same as firm transportation, there are no demand or reservation charges in these transportation contracts. As the marketplace for release of transportation capacity by the pipeline companies and other third parties has become more prevalent, the use of interruptible transportation services has diminished. We do not rely on interruptible capacity to meet peak day core demand requirements.

Avista's transportation acquisition strategy is to contract for firm transportation to serve core customers should a peak day occur in the near-term planning horizon. Since contracts for pipeline capacity are often lengthy in tenor and core customer demand needs can vary over time determining the appropriate level of firm transportation is a complex analysis of many factors. The analysis includes the projected number of firm customers and their expected annual and peak day demand, opportunities for future pipeline or storage expansions and relative costs between pipelines and their upstream supplies. This analysis is done on an annual basis as well as through the IRP. Active management of underutilized capacity through the capacity release market and engaging in optimization transactions offsets some of the transportation costs. Timely analysis is also important in order to maintain an appropriate time cushion to allow for required lead times should the need for securing new capacity arise.

STORAGE RESOURCES

Storage is a valuable strategic resource that enables improved management of a highly seasonal and varied demand profile. Storage benefits include:

- Flexibility to serve peak period needs
- Access to typically lower cost off-peak supplies
- Reduced need for higher cost annual firm transportation
- Improved utilization of existing firm transportation via off-season storage injections
- Additional supply point diversity

While there are a number of different storage facilities available to the region, Avista's existing storage resources consist solely of ownership and leasehold rights at the Jackson Prairie storage facility.

JACKSON PRAIRIE STORAGE

Avista is one-third owner, with NWP and Puget Sound Energy (PSE) in the Jackson Prairie storage project for the benefit of its core customers in all three states. Jackson Prairie Storage is an underground reservoir facility located near Chehalis, Wash. approximately 30 miles south of Olympia, Wash. The total working gas capacity of the facility is approximately 25 Bcf. Avista's current share of this capacity for core customers is approximately 8.5 Bcf and includes 398,667 Dth of daily deliverability rights.

Outside of Avista's ownership rights, we have leased an additional 95,565 Dth of Jackson Prairie capacity with 2,623 Dth of deliverability from NWP to serve Oregon customers.

INCREMENTAL SUPPLY-SIDE RESOURCE OPTIONS

Our existing portfolio of supply-side resources provides a good mix of assets to manage demand requirements for an average day and peak day events. But in anticipation of growing and changing demand requirements, we monitor the following potential resource options to meet future requirements.

SYSTEM ENHANCEMENTS

Within the context of the IRP, distribution planning plays a role but is not the primary focus. Distribution works hand in hand with supply to ensure that customer demand is met on both and average day and a peak day. There are modifications, enhancements, or upgrades that occur on the distribution system that are routine projects enhancing reliability of our system. However, in certain instances, Avista can facilitate additional peak and base load-serving capabilities through a modification or upgrade of our distribution facilities. These projects would enable more takeaway capacity from the interstate pipelines. These opportunities are geographically specific and require case-by-case study. Costs of these types of enhancements are included in the context of the IRP. A more detailed description of system enhancements (including both routine and non-routine) can be found in Chapter 8.

CAPACITY RELEASE RECALL

As discussed earlier, pipeline transportation that is not utilized to serve core customer demand can be released to other parties or optimized through daily or term transactions. Released capacity is generally marketed through a competitive bidding process and can be done on a short-term (month-to-month) or long-term basis.

We actively participate in the capacity release market and have both short-term and long-term capacity releases.

We assess the need to recall capacity or extend a release of capacity on an on-going basis. The IRP process also helps evaluate if or when we need to recall some or all of our long-term releases.

EXISTING AVAILABLE CAPACITY

In some instances there is currently available capacity on existing pipelines. NWP's mainline is currently fully subscribed; however GTN mainline has available capacity. There is some uncertainty about the future capacity availability as the demand needs of utilities and end-users vary across the region. We do model access to the GTN forward- haul and backhaul capacity as an option to meet our future demand needs.

GTN BACKHAULS

GTN backhaul services have always been available on a relatively reliable basis via displacement. However, the interconnection with the Ruby Pipeline has enabled GTN the physical capability to provide this service with minor modifications to their system. Effective in April 2012 the GTN system offers long-term firm backhaul services. Fees for utilizing this service will be provided under the existing Firm Rate Schedule (FTS-1) and currently no fuel charges will be assessed. Additional requests for firm backhaul service may necessitate the need for additional facilities and compression (i.e. fuel).

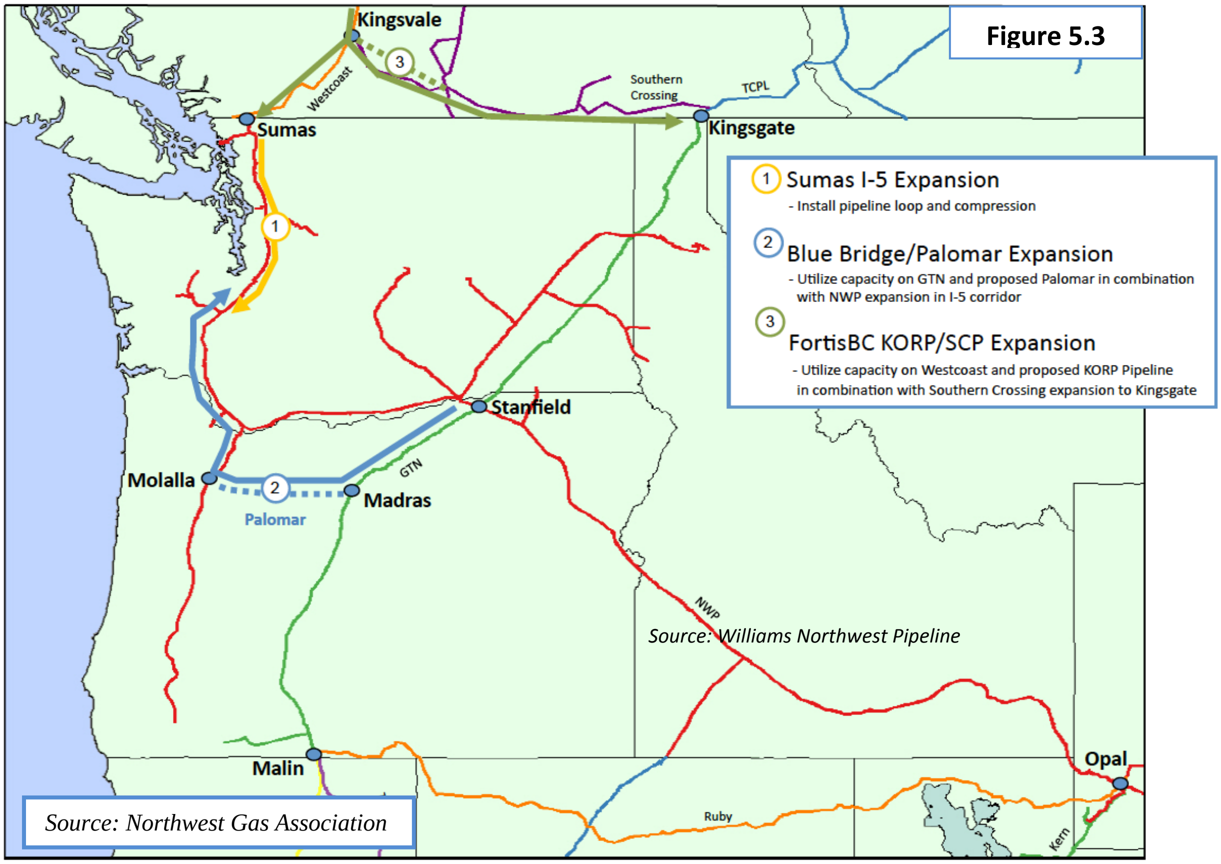
This service has the potential to be a particularly interesting solution for our Oregon customers. For example, Avista can purchase supplies at Malin, Ore. and transport those supplies to our service territory at either Klamath Falls or Medford. Malin-based natural gas supplies typically price at a premium to AECO supplies but are generally less expensive than the cost of forward-haul transporting those traditional supplies and paying the associated demand charges. The GTN system is a mileage-based system so we pay only a fraction of the forward rate if it is transporting supplies from Malin to Medford and Klamath Falls. The GTN system is approximately 612 miles long and the distance from Malin to the Medford lateral is only about 12 miles.

NEW PIPELINE TRANSPORTATION

Additional firm pipeline transportation resources are viable and attractive resource options. However, determining the appropriate level, supply source and associated pipeline path, costs and timing and determining whether or not existing resources will be available at the appropriate time, make this resource difficult to analyze. Firm pipeline capacity provides several advantages; it provides the ability to receive firm supplies at the production basin, it provides for base-load demand and it can be a low-cost option given optimization and capacity release opportunities. Pipeline capacity also has several drawbacks, including typically long-dated contract requirements, limited need in the summer months (many pipelines require annual contracts) and limited availability and/or inconvenient sizing/timing relative to resource need.

Pipeline expansions are typically more expensive than existing pipeline capacity and often require long-term annual contracts. Even though expansions may be more expensive than existing capacity, this approach may still provide the best option to us given that some of the other options discussed in this section require matching pipeline transportation anyway. Expansions may also provide reliability or access to supply that cannot otherwise be obtained through existing pipelines.

Several specific projects have been proposed for the region. The following summaries describe these projects while Figure 5.3 illustrates their location:



- **SUMAS I-5 EXPANSION**
  NWP continues to explore options to expand its service from Sumas, WA to markets along the I-5 corridor. Looping sections of 36-inch diameter pipeline with the existing pipeline and additional compression at existing compressor stations can add incremental capacity. Actual miles of pipe and incremental compression will determine the amount of capacity created, but can be scaled to meet market demand.

- **BLUE BRIDGE/PALOMAR EXPANSION**
  NWP has begun working with Palomar Gas Transmission (a partnership between NW Natural and TransCanada) to develop the Cascade (eastern) section of the previously proposed Palomar in conjunction with an expansion of NWP's existing system. The proposed 106-mile, 30-inch-diameter pipeline would extend from TransCanada's GTN's mainline, to NW Natural's system near Molalla, Ore. It would be a bi-directional pipeline with an initial capacity of up to 300 MMcf/d expandable up to 750 MMcf/d.

- **KINGSVALE-OLIVER REINFORCEMENT EXPANSION**
  Fortis, British Columbia and Spectra Energy are considering a 100-mile, 24-inch expansion project from Kingsvale to Oliver, British Columbia to expand service to the Pacific Northwest and California markets. Removing constraints will allow expansion of Spectra's T-South enhanced service offering, which provides shippers the options of delivering to Sumas or the Kingsgate market. Expansion of the bi-directional Southern Crossing system would increase capacity at Sumas during peak demand periods. Initial capacity from the Spectra system to Kingsgate would be 300 MMcf/d, expandable to 450 MMcf/d. Expanded east-to-west flow will increase delivery of supply to Sumas by an additional 150 MMcf/d.

Avista is supportive of proposals that bring supply diversity and reliability to the region. We actively engage in discussions and analysis of the potential impact to Avista of each regional proposal from a demand serving and reliability/supply diversity perspective. None of the above projects provide direct delivery connection to any of our service territories. For Avista to consider them to be a viable incremental resource to meet demand needs would require combining with additional capacity on existing pipeline resources. Given this situation we did not model these specific projects. However we do model a generic NWP expansion that extends beyond the proposed I-5 expansion to Avista's service territories.

IN-GROUND STORAGE

In-ground storage provides many advantages when gas from storage can be delivered to Avista's service territory city-gates. It can enable deliveries of natural gas to customers during cold weather events when they need it most. It also facilitates potentially lower cost supply for our customers by capturing peak/non-peak pricing differentials and potential arbitrage opportunities within individual months. Although additional storage can be a valuable resource, without deliverability to Avista's service territory, this storage cannot be considered an incremental firm peak serving resource.

JACKSON PRAIRIE

Jackson Prairie is a potential resource for expansion opportunities. Any future storage expansion capacity does not include transportation and therefore cannot be considered an incremental peak day resource. However, we will continue to look for exchange and transportation release opportunities that could fully utilize these additional resource options. Even without deliverability, we believe it can make financial sense to utilize Jackson Prairie capacity to optimize time spreads within the natural gas market and provide net revenue offsets to customer gas costs. There are no current plans for immediate expansion of Jackson Prairie. Should those plans materialize Avista would evaluate its cost-effectiveness within the context of future IRP's.

OTHER IN-GROUND STORAGE

Other regional storage facilities exist and may be cost-effective. Additional capacity at Northwest Natural's Mist facility, capacity at one of the Alberta area storage facilities, Questar's Clay Basin facility in northeast Utah, Ryckman Creek in Uinta County, Wyoming, and northern California storage are all possibilities. Again, transportation to and from these facilities to Avista's service territories continues to be the largest impediment to contracting for these options. Northern California storage opportunities may be able to overcome this hurdle by using backhaul transportation for deliveries to some of the Washington/Idaho and Oregon customers. Another issue is whether sellers of storage capacity will offer multi-year contracts or contracts with beginning dates during the timeframes that we may need these incremental resources.

SATELLITE LNG

Satellite LNG is another storage option that could be constructed within Avista's service territories and is ideal for meeting peak day or cold weather events. Satellite LNG uses natural gas that is trucked to the facilities in liquid form rather than liquefying on site. Locating the facility in the service area would avoid interstate pipeline transportation and related charges. Permitting issues notwithstanding, facilities could be located in optimal locations within the distribution system.

Estimates for this type of resource are somewhat varied because of sizing and location issues. For our modeling, we have used estimates from other facilities constructed in the area and believe these to be reasonable estimates for planning purposes. We will continue to monitor and refine the costs of developing satellite LNG while remaining mindful of lead time requirements and environmental issues.

PLYMOUTH LNG

NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. An example ratio of injection and withdrawal rates are such that it can take more than 200 days to fill to capacity, but only 3-5 days to empty. As such, the resource is best suited for needle-peak demands. Incremental transportation capacity to our service territories would have to be obtained in order for it to be a truly effective peaking resource.

This peaking resource is fully contracted and not available for contracting at this time. Given this situation, this option is not being modeled in SENDOUT® for this IRP. However, due to the fact that many of the current capacity holders are on one-year rolling evergreen contracts, it is possible that this option will again become viable in the future.

COMPANY OWNED LIQUEFACTION LNG

Instead of leasing LNG capacity from Plymouth, Avista could construct a liquefaction LNG facility within our service area. Doing so could use excess transportation during off-peak periods to fill the facility but avoid tying up transportation during peak weather events. Additional annual pipeline charges could probably be avoided.

Construction would be dependent on regulatory and environmental approval as well as cost-effectiveness requirements. Preliminary estimates of the construction, environmental, right of way, legal, operating and maintenance, required lead times, and inventory costs indicate company-owned LNG facilities have significant development risks. Due to these risks we did not include this resource in our modeling, recognizing this type of project is highly complex and there are many risk considerations that require evaluation and monitoring.

BIOGAS

Biogas typically refers to a gas produced by the biological breakdown of organic matter in the absence of oxygen. One type of biogas is produced by anaerobic digestion or fermentation of biodegradable materials such as biomass, manure or sewage, municipal waste, green waste and energy crops. This type of biogas comprises primarily methane and carbon dioxide.

Biogas is a renewable fuel so it sometimes attracts renewable energy subsidies in some parts of the world. We are not aware of any current subsidies but future stimulus or energy policies could lead to some form of financial incentives at a later time.

Biogas projects are inherently individualized, making reasonable and reliable cost estimates difficult to obtain. Project sponsorship has many complex issues and the more likely participation in such a project is as a long-term contracted purchaser. We did not consider biogas as a resource in this planning cycle but remain receptive to such projects as they are proposed.

SUPPLY SCENARIOS

For this IRP we modeled three supply scenarios. Table 5.2 lists the supply scenarios and Appendix 5.2 provides the details on what is included in each of these scenarios. Additional detail about the results of these supply scenarios modeled is included in Chapters 6 and 7.

Table 5.2 Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Fully Subscribed

- **EXISTING RESOURCES**
  Represents all resources currently owned or contracted by Avista.
- **EXISTING + EXPECTED AVAILABLE**
  Existing resources plus supply resource options expected to be available when resource needs are identified. This includes: currently available forward and backhaul GTN, capacity release recalls, NWP expansions and satellite LNG.
- **GTN FULLY SUBSCRIBED**
  Availability of GTN capacity is unavailable due to significant contracting driven by increased demand.

SUPPLY ISSUES

The importance of shale gas in the North American supply mix has fundamentally altered current and the outlook of future natural gas prices and infrastructure. While it appears certain that North American supply is in good shape there are issues that can impact the cost and availability.

- **HYDRAULIC FRACTURING**
  "Fracking" has become the bad word of the natural gas and oil industry. Improvements in hydraulic fracturing (HF), a sixty-year-old technique used to extract oil and natural gas from shale rock formations, has enabled access to previously uneconomic resources. However, the process does not come without its challenges. Movies and articles in the national newspapers have further fueled a movement to cease this drilling practice. There is worry that HF is contaminating aquifers, increasing air pollution, and most recently causing earthquakes. The wide spread publicity generated interest in the production process and caused some states to issue bans or moratoriums on drilling until further research was conducted.

  To that end many levels of government, industry, and universities have or are engaged in conducting studies to better understand the actual and potential impacts of HF. Industry has been working to refute these claims by focusing on ensuring companies use "best practices" for well drilling, disclosing the fluids used in the HF processing, and implementing "green completions" for wells. The state governments are participating in independent audits of their regulations to ensure that proper oversight is in place. The EPA is engaged in a study and will issue a report in late 2012 to determine the effects of HF on water and air. Finally, the United States Geological Survey (USGS) has begun to study the correlation between seismic activity and HF. The outcome of these audits, studies, and further research could greatly impact both the cost and availability of natural gas and oil.

- **LNG – EXPORT IS THE NEW IMPORT**
  A few short years ago, North America was going to be reliant on importing LNG in order to fill the supply and demand gap and the gas market was heading to a more global pricing structure. Now wide

spread shale availability and low production costs have upended the US importing LNG industry. Europe and Asia have prices that are more favorable so in an effort to maximize margins many import facilities have petitioned to become exporters.

On a national level, in April 2012 Sabine Pass LNG was granted the authority by FERC to export 2.2 Bcf/d. Sabine Pass LNG is the first in the US to be granted permission, however there are many more in the queue. Regionally, two proposed LNG terminals in Oregon, Jordan Cove LNG and Oregon LNG are looking to export. In Canada, the National Energy Board (NEB) granted Kitimat LNG in British Columbia a twenty year license to export LNG to serve international markets. When and where this happens, how many, what volume and how our natural gas prices are affected are continuing to be debated.

GREEN TURNS TO BLUE

The desire to reduce reliance on fossil fuels, improve the carbon footprint, and lessen our need for foreign oil sparked a flurry of legislative activity. State mandated renewable portfolio standards (RPS), carbon taxes or cap and trade programs, and natural gas vehicles (NGV) became common news.

RPS mandates required electric utilities to "green up" their portfolios. In many cases, this means reducing reliance on coal and investing in renewable sources of energy such as wind, solar, and nuclear. Wind and solar in particular became the resource of choice for most utilities, unfortunately these are intermittent and would require reliable and controllable backup. Additional gas fired power generation will be necessary to support the renewable fleet.

Helping to encourage the change to cleaner and greener energy was the concept of a carbon tax. This would provide a means to make the cost of renewable on par with less expensive fossil fuels. There were many different plans proposed on how to implement the additional costs. However, rapid adoption of such legislation did not occur. As the depth of the recession began to be felt, legislators realized burdening already strapped taxpayers would be detrimental to an already fragile economy. The economy is still healing, but that does not change the importance of reducing our carbon footprint. There continues to be discussion about a carbon tax. The timing and magnitude of the tax has been pushed out many years and is at a much lower level than originally proposed.

With oil prices surging and driving high gasoline prices, many are looking to reduce the nation's need for foreign oil. This push has renewed investments in NGV infrastructure. T. Boone Pickens and Clean Energy are often in the headlines discussing how NGV can play an important role in the energy and transportation future. Much of the transportation focus has been on long haul trucks and fleet vehicles such as refuse trucks and public transportation. The cost to convert these vehicles is significant, however many are making the switch.

PIPELINE AVAILABILITY

The pipeline infrastructure of the Northwest is sparse when compared to the Gulf or East Coast. As we move closer and closer to a more renewable energy future demand for natural gas via gas-fired generation will increase. Pipeline capacity is the link between gas and power. LDCs will have to compete with power generators for pipeline capacity. The new mix could alter current pipeline operations and the potential availability of infrastructure to the region.

MARKET-RELATED RISKS AND RISK MANAGEMENT

While risk management can be defined in a variety of ways, the integrated resource plan focuses on two areas of risk: the financial risk under which the cost to supply customers will be unreasonably high or unreasonably volatile, and the physical risk that there may not be enough natural gas resources (either the transportation capacity or the commodity) to serve core customers.

Avista has a Risk Management Policy that describes the policies and procedures associated with financial and physical risk management. The Risk Management Policy addresses, among other things, issues related to management oversight and responsibilities, internal reporting requirements, documentation and transaction tracking, and credit risk.

There are two internal organizations that assist in the establishment, reporting and review of Avista's business activities as they relate to management of natural gas business risks:

- The Risk Management Committee consists of several corporate officers and senior-level management. The committee establishes the Risk Management Policy and monitors compliance. They receive regular reports on natural gas activity and meet regularly to discuss market conditions, hedging activity and other natural gas-related matters.
- The Strategic Oversight Group exists to coordinate natural gas matters among internal natural gas-related stakeholders and to serve as a reference/sounding board for strategic decisions, including hedges, made by the Natural Gas Supply department. Members include representatives from the Accounting, Regulatory, Credit, Power Resources and Risk Management departments. While the Natural Gas Supply department is responsible for implementing hedge transactions, the Group provides input and advice.

❚❚ ACTION ITEMS

With no immediate need to acquire incremental supply side resources to meet peak day demands Avista's focus in the near term will include the following:

- Continue to monitor supply resource trends including the availability and price of natural gas to the regions, exporting LNG, Canadian natural gas imports, regional plans for gas fired generation and its affect on pipeline availability, as well as future regional pipeline and storage infrastructure plans.
- We will also monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.

❚❚ CONCLUSION

Avista is committed to providing reliable supplies of natural gas to its customers. We procure these supplies with a diversified plan that seeks to competitively acquire natural gas supplies while reducing exposure to short-term price volatility through a strategy that includes hedging, storage utilization and index purchases. We have long-term contracts for firm pipeline transportation capacity from many supply points and also own and lease firm natural gas storage capacity sufficient to serve customer demand during peak weather events and throughout the year.

CHAPTER 6 – INTEGRATED RESOURCE PORTFOLIO

OVERVIEW

This chapter combines all previously discussed IRP components and the model used to determine resource deficiencies during the 20-year planning horizon. This chapter also provides an analysis of potential resource options and displays the model-selected best cost/risk resource options to meet resource deficiencies.

The foundation for integrated resource planning is the demand planning criteria used for developing demand forecasts. Avista currently uses the “coldest day on record” as its weather planning standard for determining peak-day demand. This is consistent with our past IRPs and is more fully described in Chapter 3 – Demand Forecasts. We utilize historic peak and average weather data for each demand region for this IRP. We plan to serve our expected peak day in each demand region with firm resources. Firm resources include natural gas supplies, pipeline transportation and storage resources. In addition to planning for peak requirements, we also plan for non-peak periods such as winter, shoulder and summer demand. Our modeling process includes running an optimization for every day of the 20-year planning period.

It is assumed that on a peak day all interruptible customers have left the system in order to provide service to firm customers. Avista does not make firm commitments to serve interruptible customers. Therefore, our IRP analysis of demand-serving capabilities only focuses on the residential, commercial and firm industrial classes.

Our supply forecasts are increased between 1.0 percent and 3.0 percent on both an annual and peak-day basis to account for additional supplies that are purchased primarily for pipeline compressor station fuel. The percentage of additional supply that must be purchased is governed through FERC and National Energy Board approved tariffs.

SENDOUT® PLANNING MODEL

The SENDOUT® Gas Planning System from Ventyx is used to perform integrated resource optimization. The SENDOUT® model was purchased in April 1992 and has been used in preparing all IRPs since then. Avista has a long-term maintenance agreement with Ventyx that allows us to receive software updates and enhancements. These enhancements include software corrections and improvements brought on by industry change.

SENDOUT® is a linear programming model widely used to solve natural gas supply and transportation optimization questions. Linear programming is a proven technique used to solve minimization/maximization problems. SENDOUT® looks at the complete problem at one time within the study horizon, while taking into account physical limitations and contractual constraints

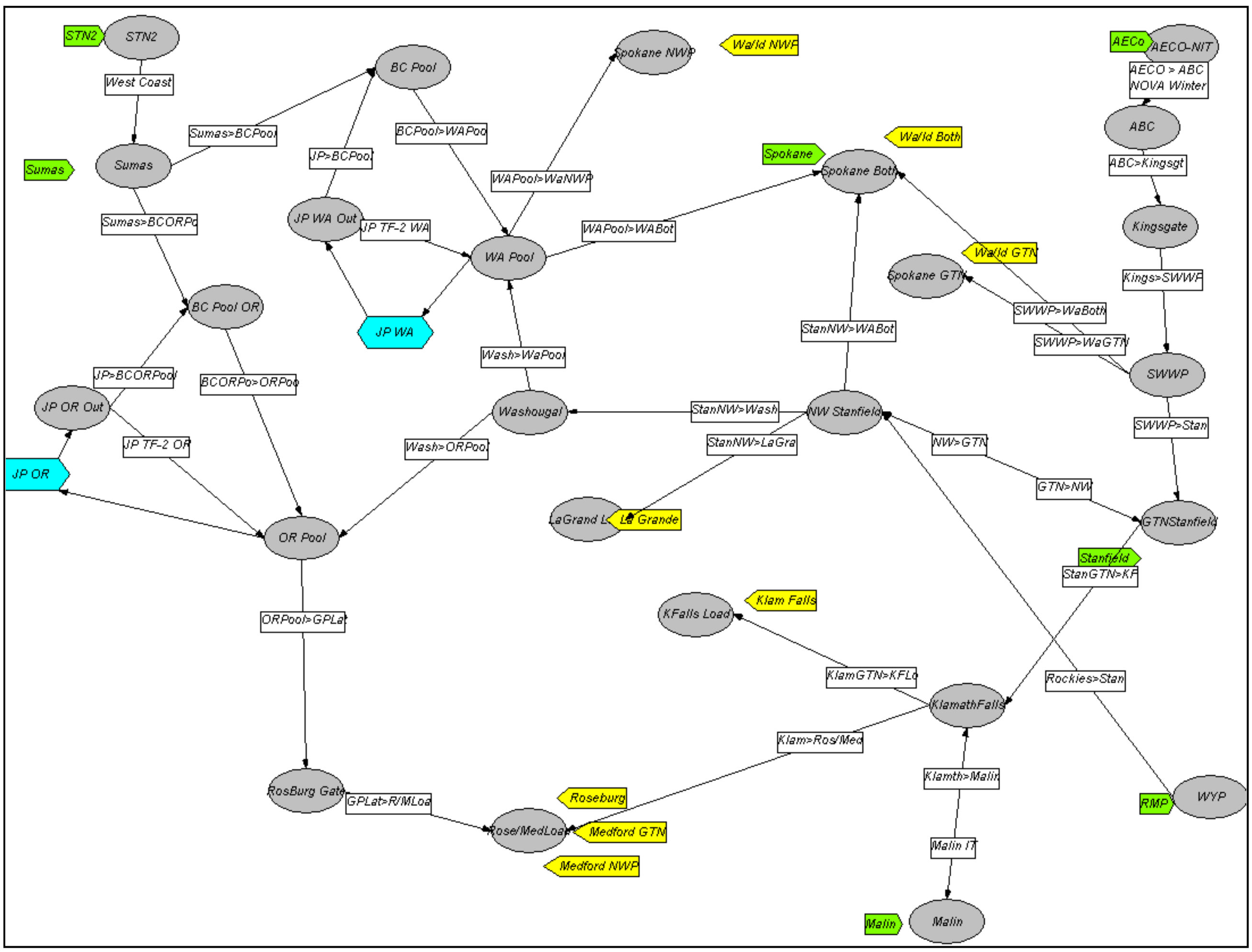
The software analyzes thousands of variables and evaluates possible solutions to generate a least cost solution. The model uses the following variables:

- Demand data, such as customer count forecasts and demand coefficients by customer type (e.g. residential, commercial and industrial)
- Weather data – minimum, maximum and average temperatures
- Existing and potential transportation data which describes to the model the network for the physical movement of the natural gas and associated pipeline costs

- Existing and potential supply options including supply basins, revenue requirements as the key cost metric for all asset additions, and prices
- Natural gas storage options with injection/withdrawal rates, capacities and costs
- DSM potential

Figure 6.1 is a SENDOUT® network diagram of our demand centers and resources. This diagram illustrates Avista's current transportation and storage assets, flow paths and constraint points.

FIGURE 6.1 SENDOUT® MODEL DIAGRAM



The SENDOUT® model also provides a flexible tool to analyze potential scenarios such as:

- Pipeline capacity needs and capacity releases
- Effects of different weather patterns upon demand
- Effects of natural gas price increases upon total natural gas costs
- Storage optimization studies
- Resource mix analysis for DSM
- Weather pattern testing and analysis
- Transportation cost analysis

- Avoided cost calculations
- Short-term planning comparisons

SENDOUT® also includes Monte Carlo capabilities, which facilitates price and demand uncertainty modeling and detailed portfolio optimization techniques to produce probability distributions. More information and analytical results are located in Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

RESOURCE INTEGRATION

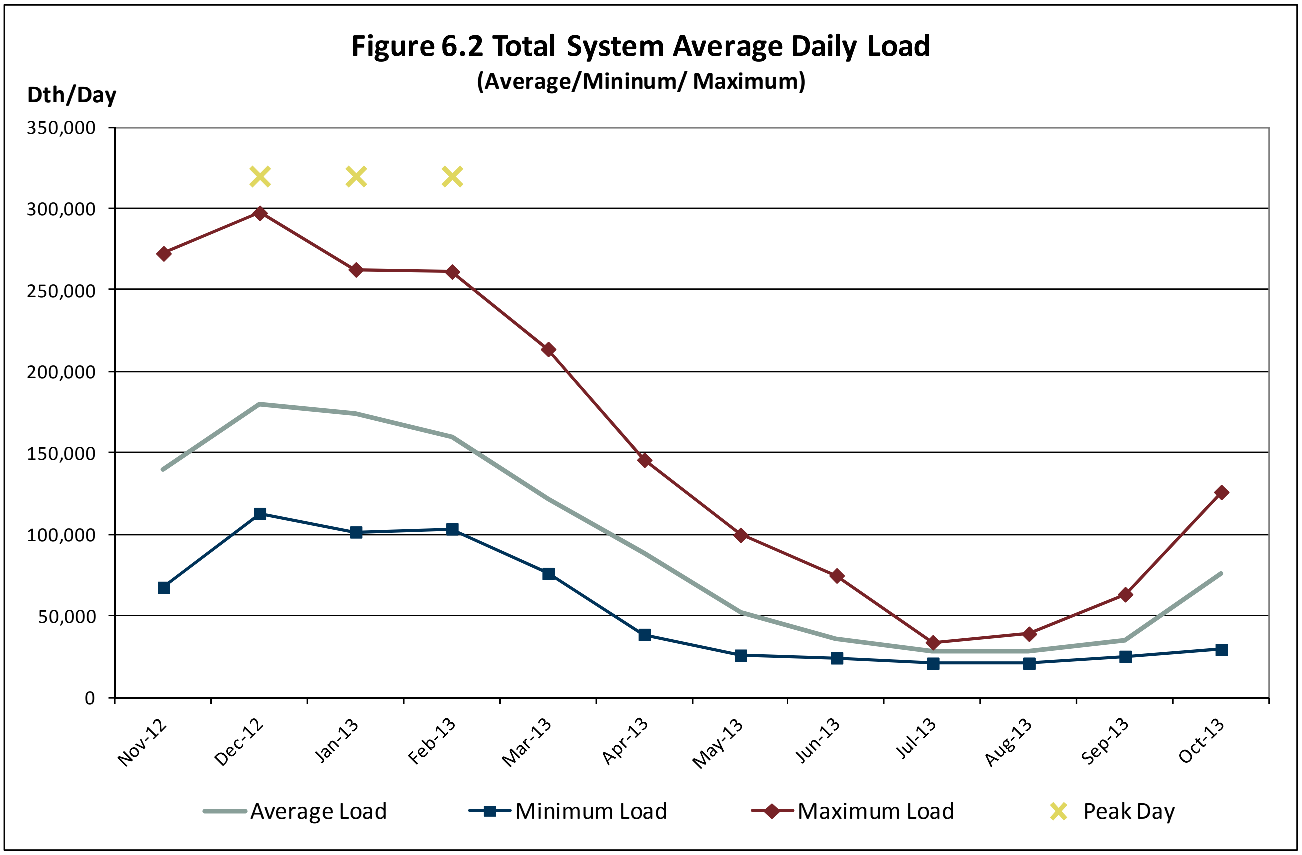
We have defined the planning methodologies, described the modeling tools and identified the existing and potential resources. The following summarizes the comprehensive analysis of bringing demand forecasting and existing and potential supply and demand-side resources together to form our 20-year, risk adjusted least-cost plan.

DEMAND FORECASTING

Avista's demand forecasting approach is described in detail in the Chapter 3 - Demand Forecasts.

We forecast demand in the SENDOUT® model in eight service areas given the existence of distinct weather and demand patterns for each area and pipeline infrastructure dynamics. The SENDOUT® areas are Washington/Idaho (disaggregated into three sub-areas because of pipeline flow limitations), Medford (disaggregated into two sub-areas because of pipeline flow limitations) and Roseburg, Klamath Falls and La Grande. In addition to area distinction, we also model demand by customer class within each area. The relevant customer classes in Avista's service territories are residential, commercial and firm industrial customers.

Customer demand reflects a highly weather-sensitive component. Avista's customer demand is not only highly seasonable but also highly variable. Figure 6.2 captures this variability showing our monthly system-wide average demand, minimum demand day observed in each month, and maximum demand day observed in each month, and our winter projected peak day demand for the first year of our Expected Case forecast as determined in SENDOUT®.



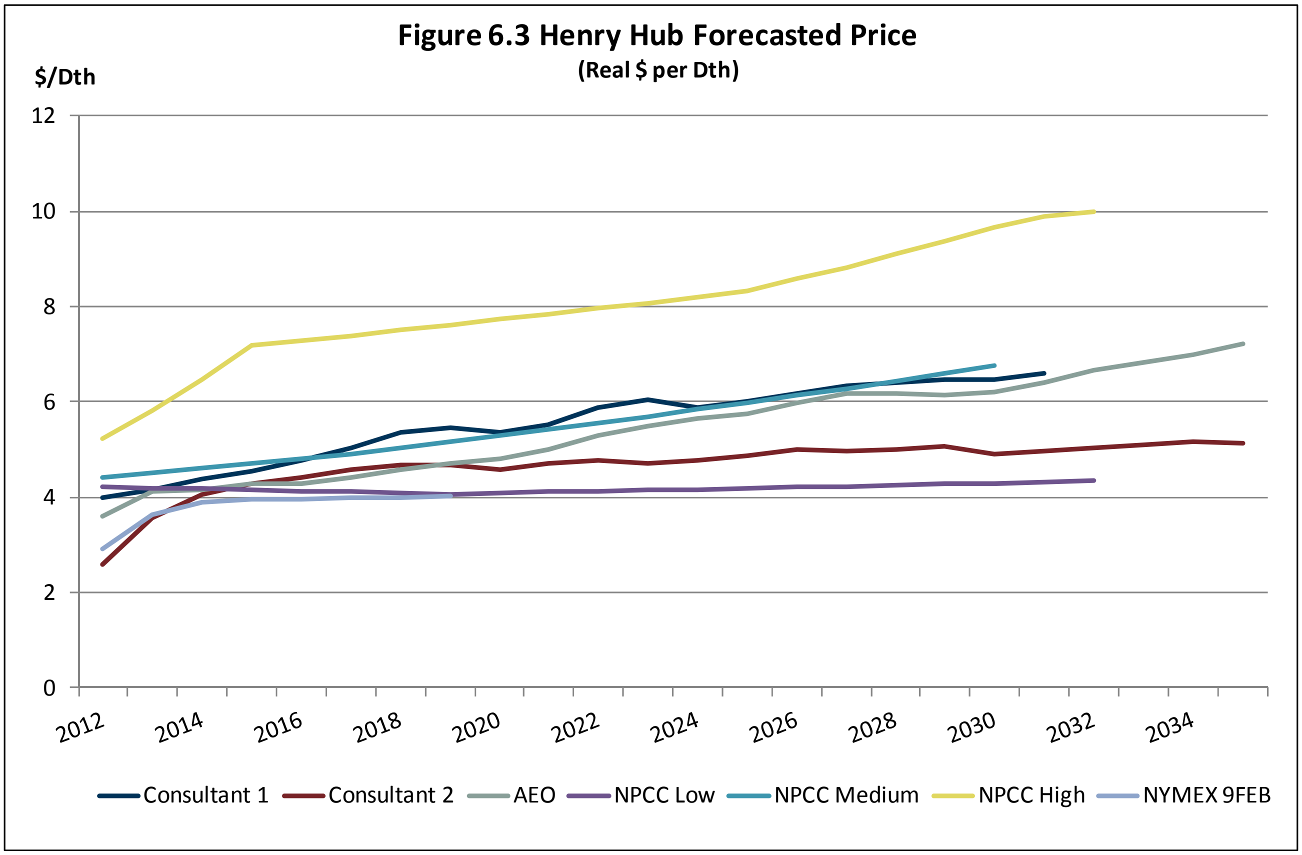
NATURAL GAS PRICE FORECASTS

Natural gas prices are a fundamental component of the IRP. The commodity price is a significant component of the total cost of a resource option. This in turn affects the avoided cost threshold for determining cost-effectiveness of conservation measures. We also recognize the price of natural gas influences consumption, so we include price elasticity analysis in our demand evaluation (see Chapter 3 – Demand Forecasts).

The natural gas price outlook has changed dramatically in recent years in response to several influential events and trends affecting the industry. The recession, shale gas production and potential climate change legislation encouraging natural gas-fired power generation to replace coal burning power plants. Due to the rapidly changing environment and uncertainty in predicting future events and trends, modeling a range of forecasts is necessary.

Many additional factors influence natural gas pricing and volatility, such as regional supply/demand issues, weather conditions, hurricanes/storms, storage levels, gas-fired generation, infrastructure disruptions and infrastructure additions (e.g. new pipelines, LNG terminals).

Even though we continually monitor these factors, we cannot accurately predict future prices for the 20-year horizon of this IRP. We have reviewed several price forecasts from credible sources. Figure 6.3 depicts the price forecasts we considered in our analyses.



Selecting the price curves can be more art than science. With assistance and concurrence of the TAC we selected high, expected and low price curves to consider possible outcomes and the impact on resource planning. The price curves we have selected have variation and provide reasonable upper and lower bounds, which is consistent with our theme of stretching modeling assumptions to address uncertainty in the planning environment. These curves are shown in real dollars in Figure 6.4 and nominal dollars in Figure 6.5. Additionally, stochastic modeling of natural gas prices is also completed. The results from that analysis are shown in Chapter 7 – Alternate Scenarios, Portfolios, and Stochastic Analysis.

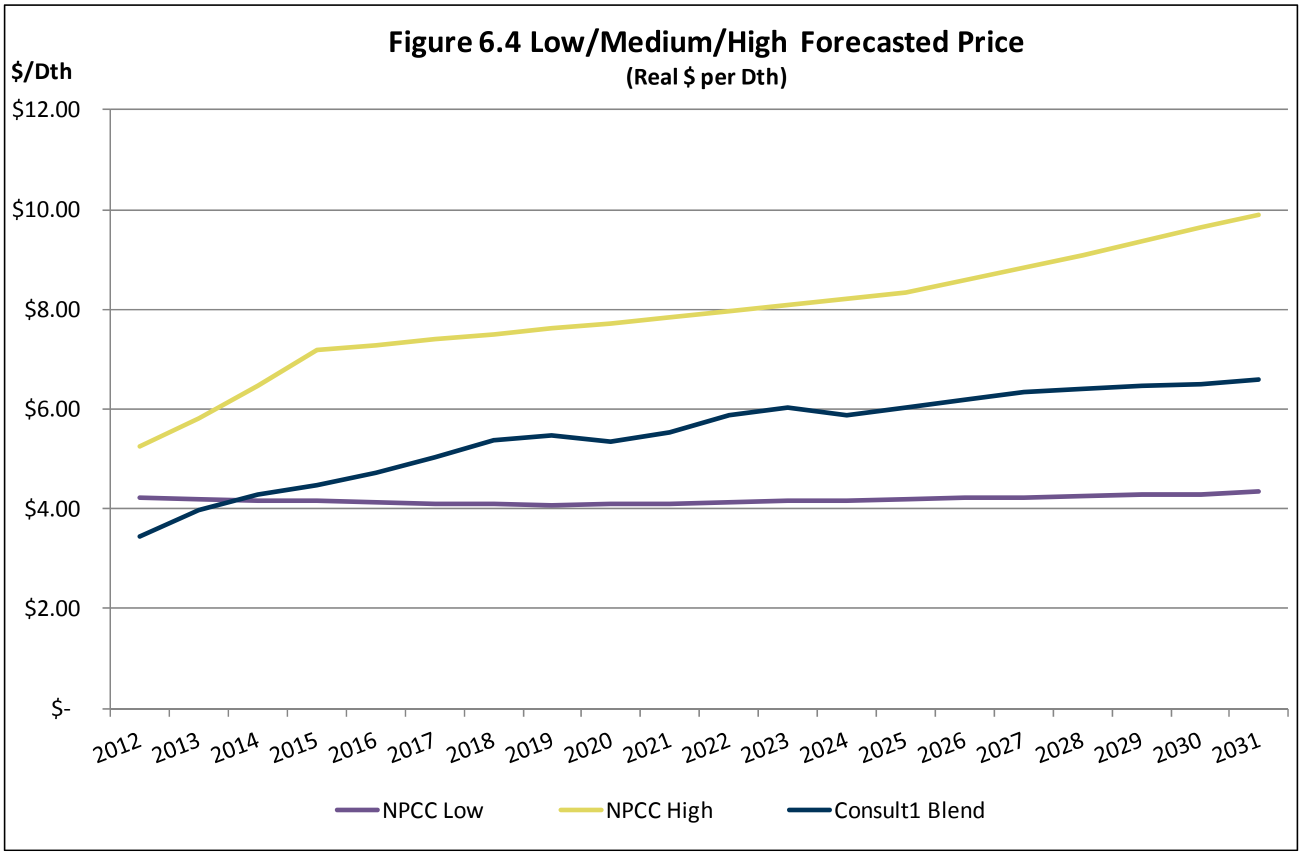


Figure 6.4 Low/Medium/High Forecasted Price
(Real $ per Dth)
$/Dth
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
NPCC Low
NPCC High
Consult1 Blend

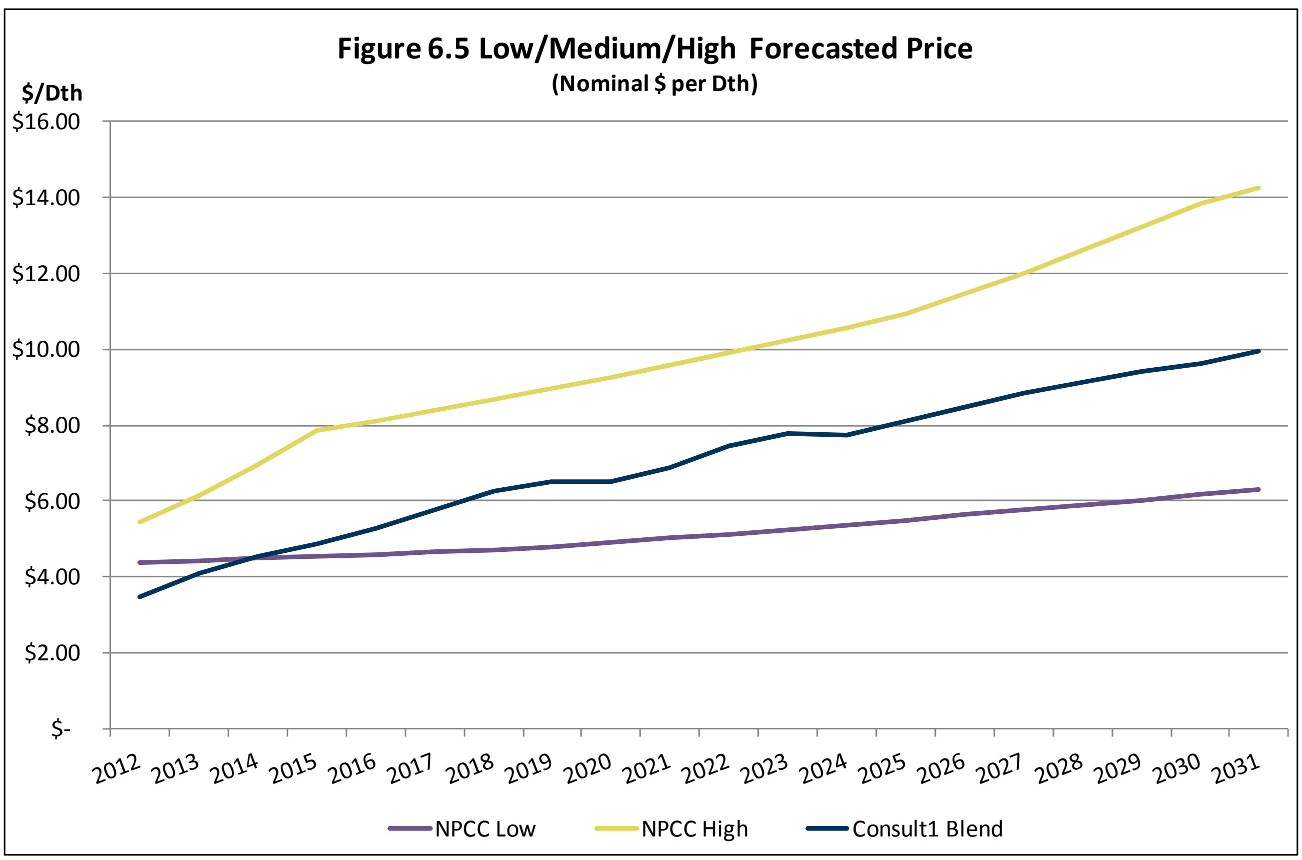


Figure 6.5 Low/Medium/High Forecasted Price
(Nominal $ per Dth)
$/Dth
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
NPCC Low
NPCC High
Consult1 Blend

Each of the price forecasts above are for Henry Hub, which is located in Louisiana just onshore from the Gulf of Mexico. Henry Hub is widely recognized as the most important pricing point in the U.S. because of its proximity to a large portion of U.S. natural gas production and the sheer volume traded in the daily or spot market as well as the forward markets via the New York Mercantile Exchange's (NYMEX) futures contracts. Consequently, all other trading points tend to be priced off of the Henry Hub.

The primary physical supply points at Sumas, AECO, and the Rockies (and other secondary regional market hubs) ultimately determine Avista's costs. Prices at these points typically trade at a discount or negative basis differential to Henry Hub primarily because of their relative close proximity to the two largest natural gas basins in North America (the WCSB and the Rockies).

Table 6.1 shows the Pacific Northwest regional prices from our consultants, historic averages, and the prior IRP as a percent of Henry Hub price along with historical comparisons.

Table 6.1 Regional Price as a Percent of Henry Hub Price

	AECO	Sumas	Rockies	Malin	Stanfield
Consultant1 Forecast Average	88.60%	89.90%	90.80%	92.30%	91.40%
Consultant2 Forecast Average	86.20%	92.50%	92.80%	94.10%	92.60%
Historic Cash Three-Year Average	89.90%	95.50%	88.10%	97.00%	95.60%
Prior IRP	92.70%	95.20%	85.60%	94.10%	93.70%

This IRP used monthly prices for modeling purposes because of our heavily winter-weighted demand profile. Table 6.2 depicts the monthly price shape we used in this IRP. A slight change to the shape of the pricing curve has occurred since the last IRP. Driven primarily by supply availability, the forecasted differential between winter and summer pricing has come in to some extent when compared to historic data.

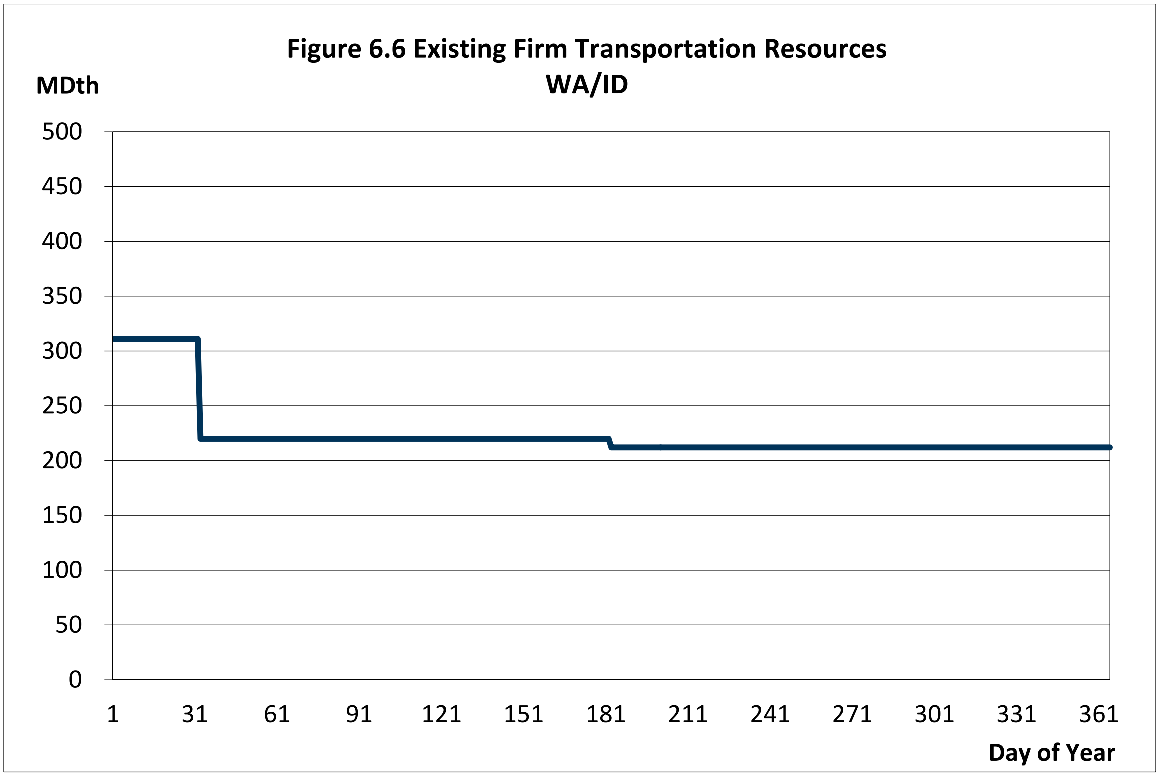
Table 6.2 Monthly Price as a Percent of Average Price

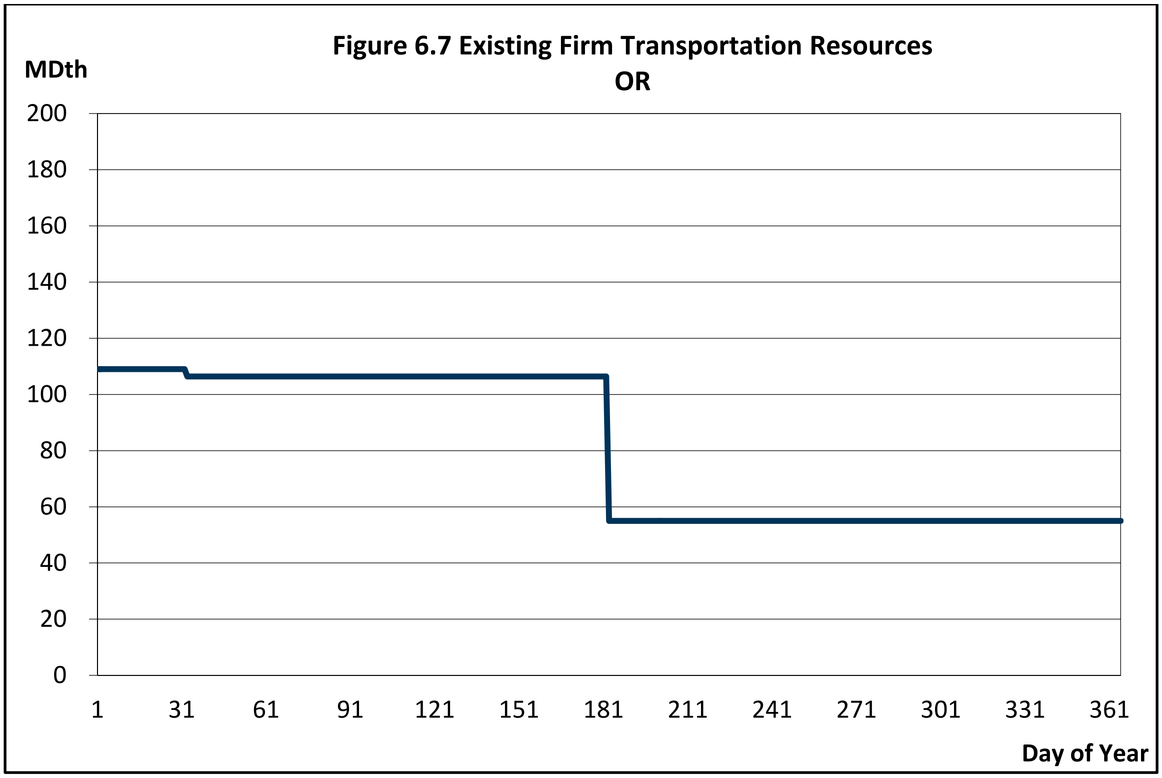
	Jan	Feb	Mar	Apr	May	Jun
Consult1	101%	101%	98%	98%	98%	100%
Consult2	103%	102%	99%	98%	99%	101%
Historic First of Month Index Three-Year Average	130%	113%	101%	94%	96%	96%
Prior IRP	107%	108%	103%	93%	93%	94%
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Consult1	102%	103%	100%	100%	100%	102%
Consult2	101%	101%	97%	97%	98%	104%
Historic First of Month Index Three-Year Average	104%	100%	84%	93%	92%	97%
Prior IRP	94%	94%	95%	96%	101%	106%

Consistent with our selection for Henry Hub prices, we selected Consultant 1's forecast of regional prices and monthly shape. Appendix 6.1 contains detailed monthly price data behind the summary table information discussed above.

TRANSPORTATION AND STORAGE

Valuing natural gas supplies is a critical first step in resource integration. Equally important is capturing all costs to deliver the gas to the customer. Daily capacity of our existing transportation resources (described in Chapter 5 – Supply-Side Resources) is represented by the firm resource duration curves depicted in Figures 6.6 and 6.7.





Current rates for capacity are in Appendix 5.1. Forecasting future pipeline rates can be a challenge as we need to estimate the amount and timing of rate changes. Our estimates and timing of future rate increases are based on knowledge obtained from industry discussions and participation in various pipeline rate cases. This IRP assumes that pipelines will file to recover costs at rates equal to increases in GDP (see Appendix 6.2 – General Assumptions).

DEMAND-SIDE MANAGEMENT

Chapter 4 – Demand-side Resources describes the methodology used to identify conservation potential and the interactive process deployed in SENDOUT® that computes avoided cost thresholds for determining cost effectiveness of conservation measures on an equivalent basis with supply-side resources.

PRELIMINARY RESULTS

After incorporating the above data into the SENDOUT® model, we then generate an assessment of demand compared to existing resources for several scenarios. The demand results from these cases are discussed in Chapter 3 – Demand Forecasts, with additional details supported in the Appendices 3.1 through 3.10.

Figures 6.8 through 6.11 graphically represent summaries of Average Case demand compared to existing resources. This demand is net of DSM savings and shows the adequacy of our resources under normal weather conditions. For this case, current resources meet our demand needs over the planning horizon.

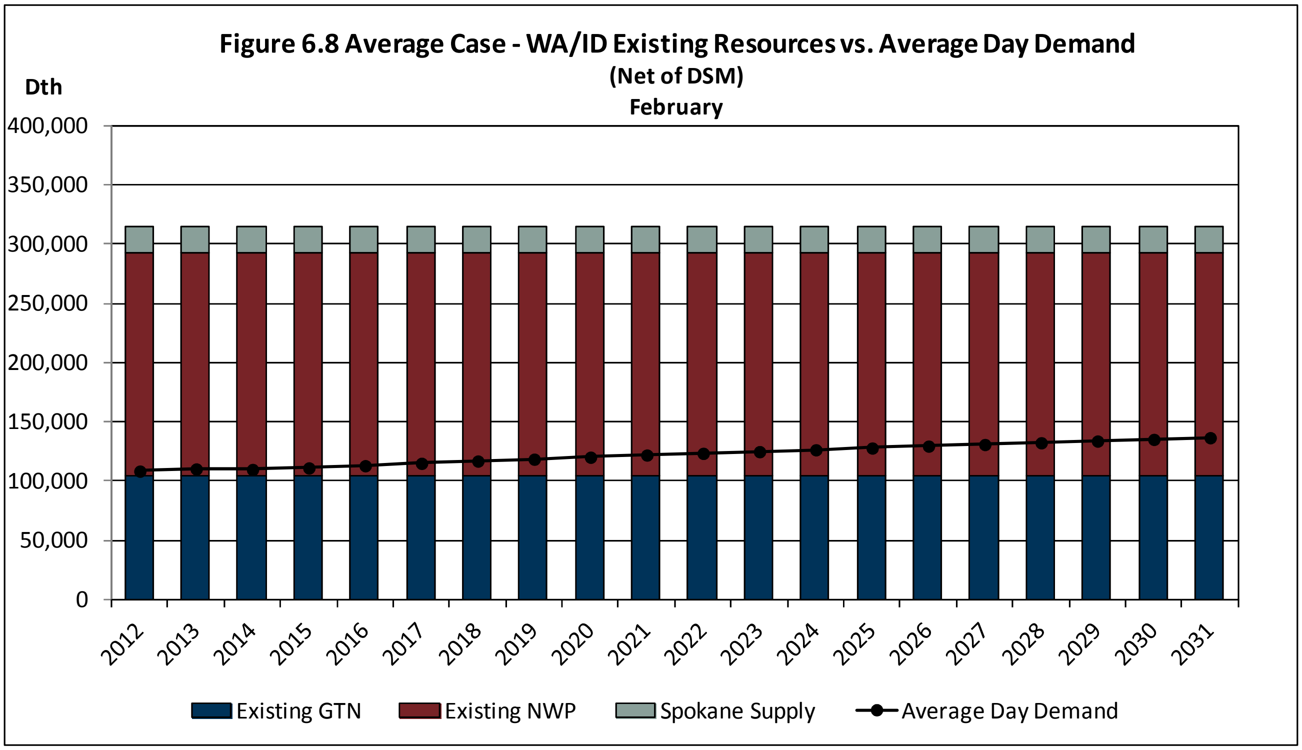


Figure 6.8 Average Case - WA/ID Existing Resources vs. Average Day Demand
(Net of DSM)
February
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP
Spokane Supply
Average Day Demand

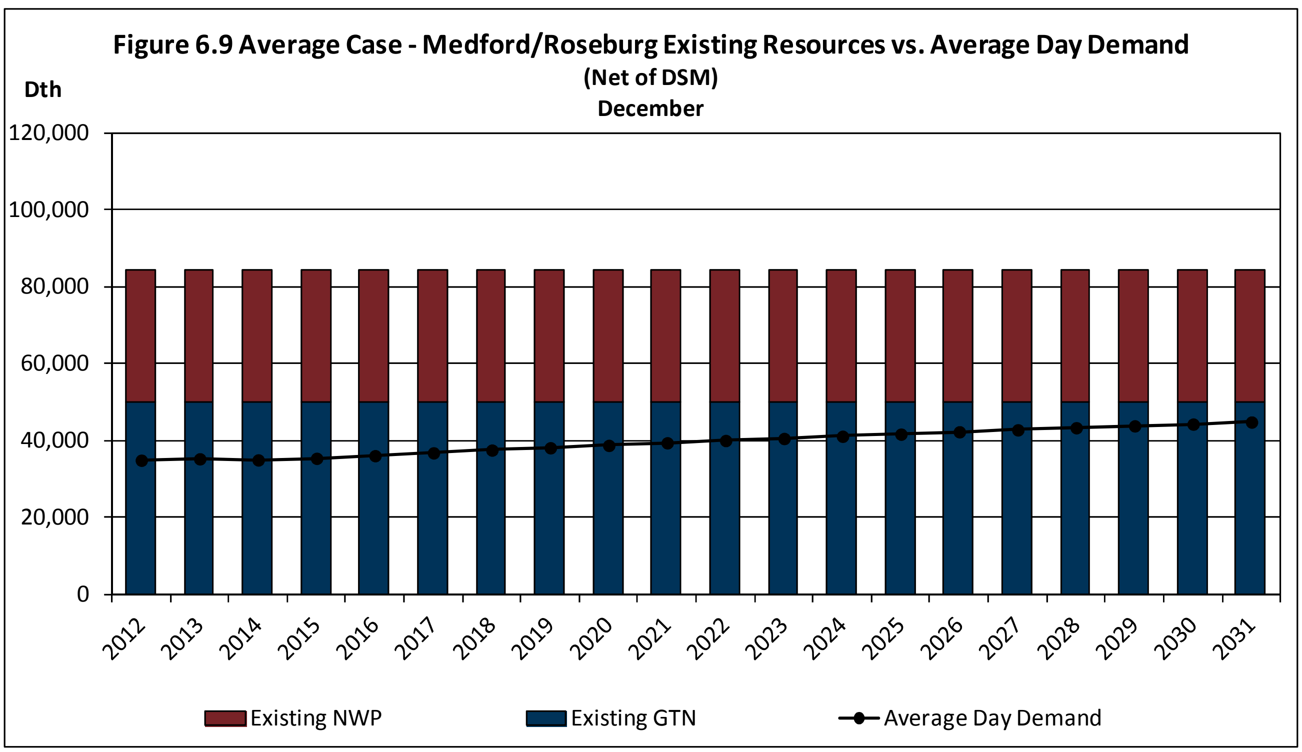
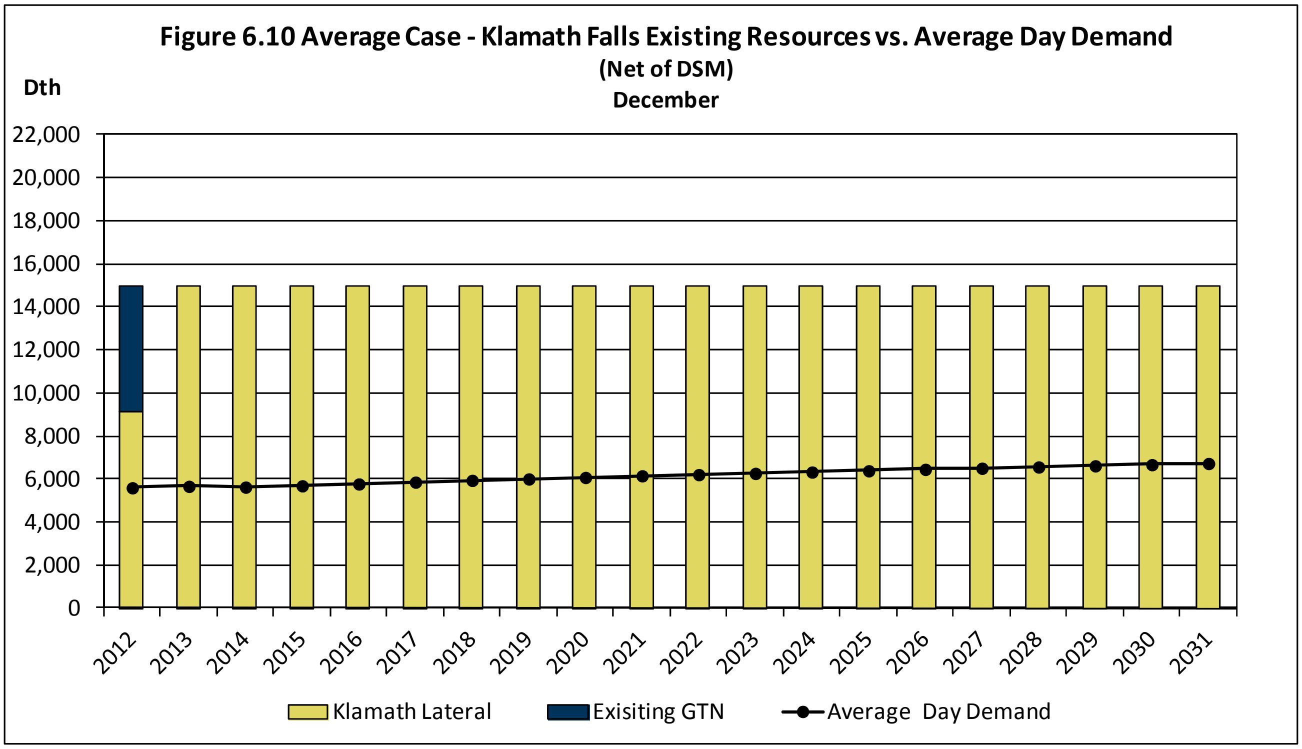
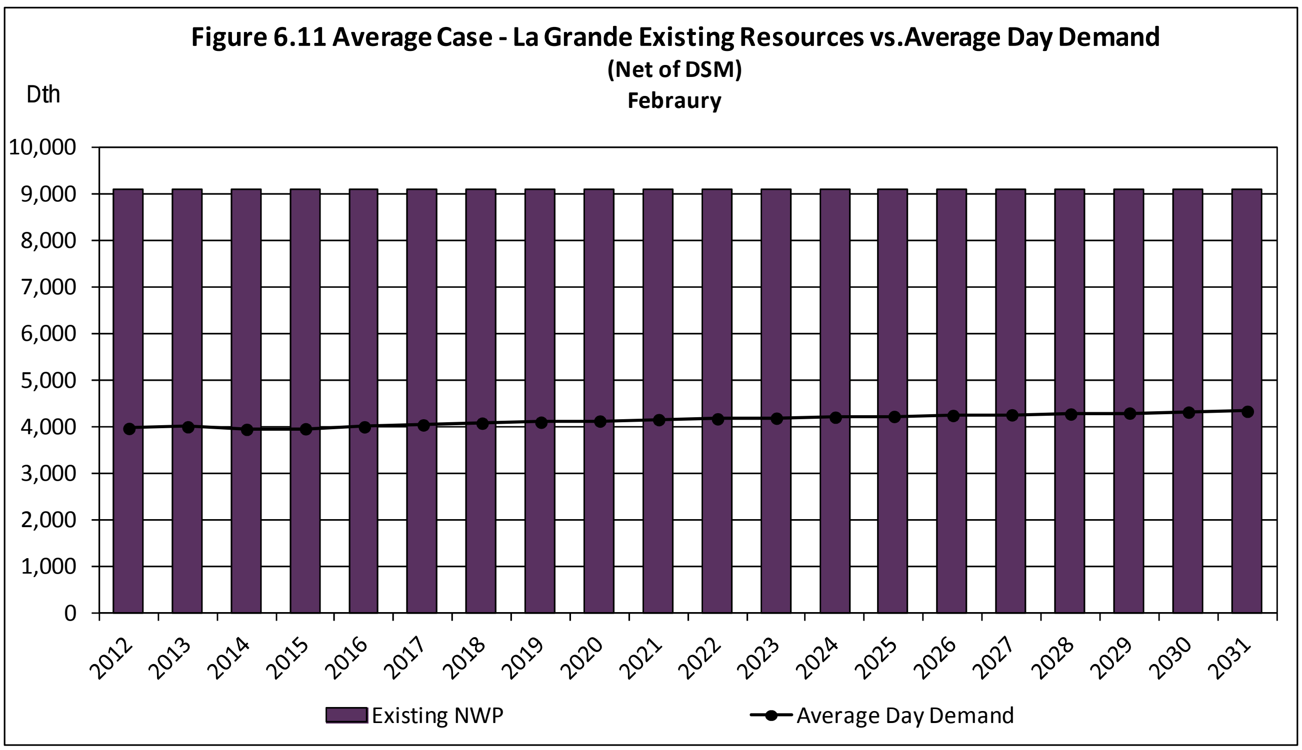


Figure 6.9 Average Case - Medford/Roseburg Existing Resources vs. Average Day Demand
(Net of DSM)
December
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing NWP
Existing GTN
Average Day Demand





Figures 6.12 through 6.15 graphically represent summaries of Expected Case peak day demand compared to existing resources, as well as demand comparisons to our prior IRP. This demand is net of DSM savings. This comparison shows by service territory the amount and timing of deficits over the planning horizon.

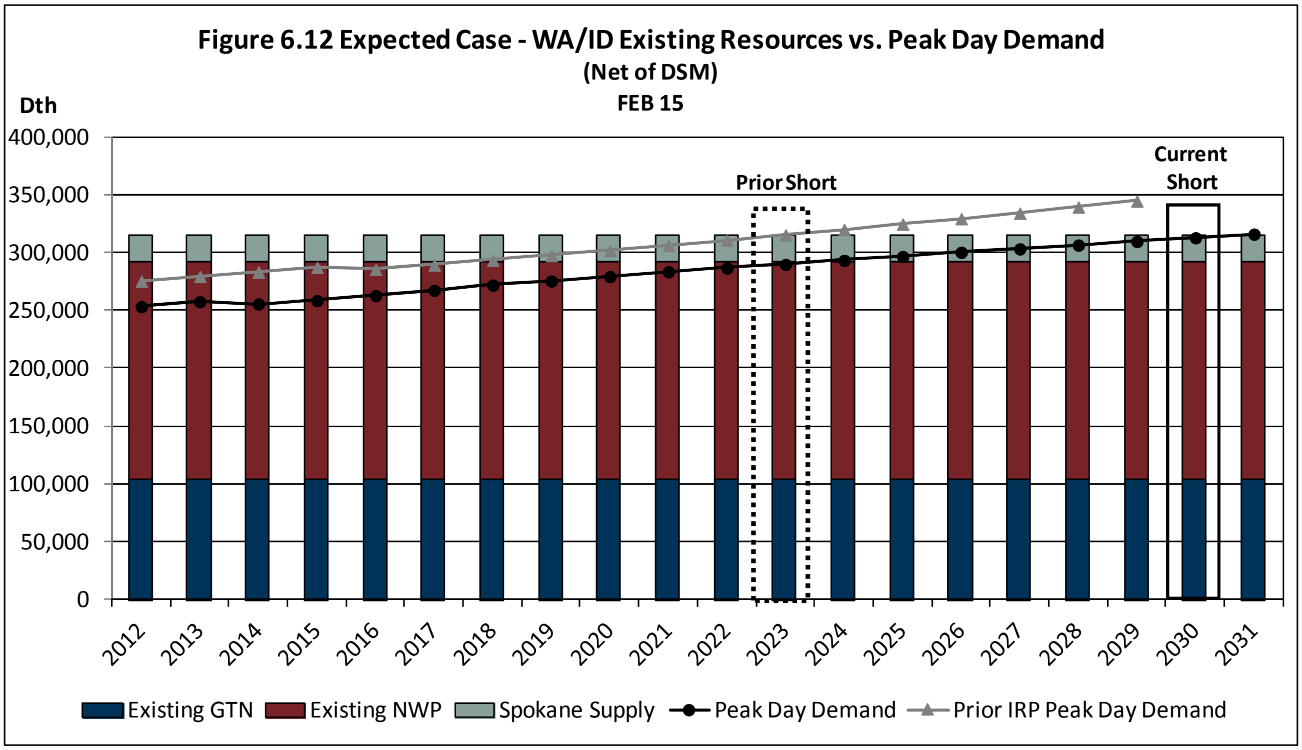


Figure 6.12 Expected Case - WA/ID Existing Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Prior Short
Current Short
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Existing GTN
Existing NWP
Spokane Supply
Peak Day Demand
Prior IRP Peak Day Demand

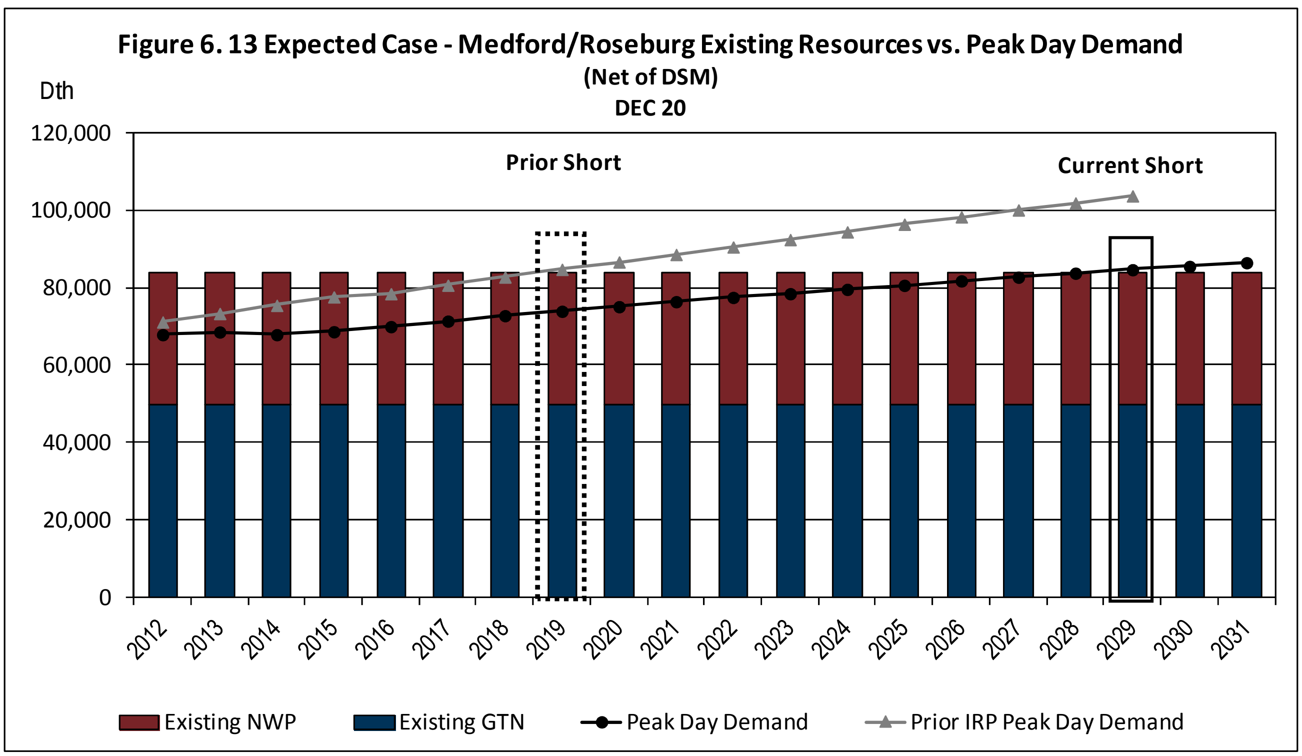
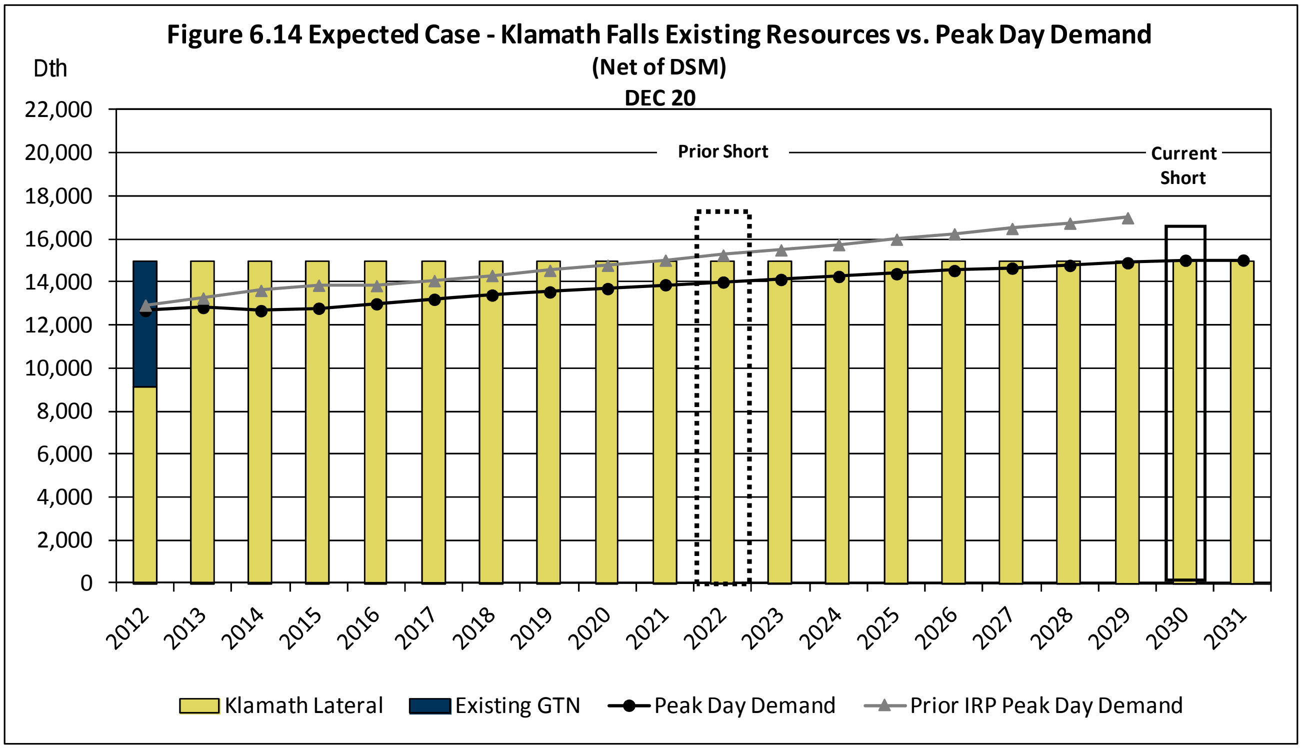
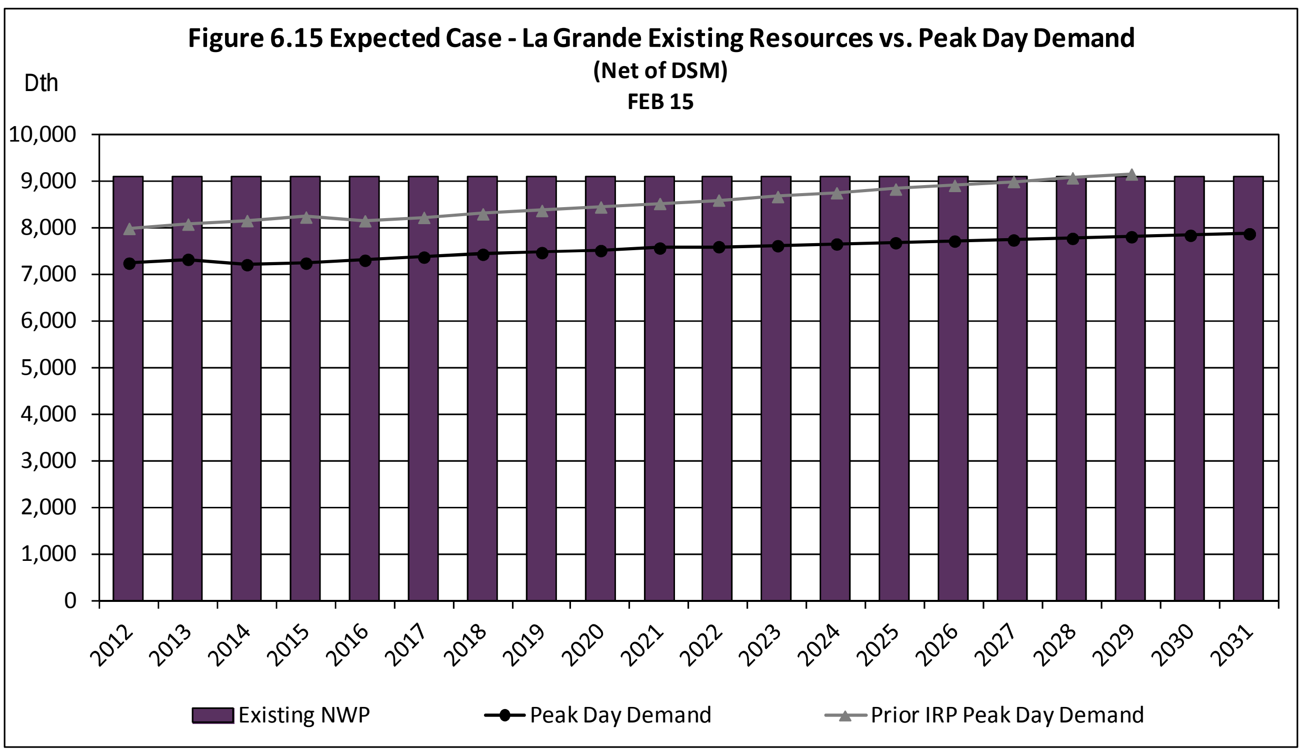


Figure 6. 13 Expected Case - Medford/Roseburg Existing Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Prior Short
Current Short
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Existing NWP
Existing GTN
Peak Day Demand
Prior IRP Peak Day Demand





These charts show that when resource shortages occur they are well into the future. In the Expected Case for Washington and Idaho, the system first becomes unserved in 2030. In Oregon, the first unserved year is in Medford/Roseburg in 2029 followed by Klamath Falls in 2030. The La Grande service territory does not go unserved at any time during the 20-year planning horizon. This surplus resource situation provides ample time to carefully monitor, plan and act on potential resource additions.

However, an important risk with respect to identified capacity shortages is the slope of forecasted demand growth which is almost flat. However, if demand accelerates the need for additional resources will also accelerate by several years. This “flat demand risk” necessitates close monitoring of signs of accelerating demand and careful evaluation of lead times to acquire preferred incremental resources.

Table 6.3 quantifies the forecasted total demand (net of DSM savings) and unserved demand from the above charts, identifying the amount of deficiencies by region and growth in deficiencies over time. The next step is to determine the best risk/least cost resources to satisfy these deficiencies.

Table 6.3 Peak Day Demand – Served and Unserved (MDth/d)
Before Resource Additions & Net of DSM Savings

Case	Gas Year	La Grande Served	La Grande Unserved	La Grande Total	La Grande % of Peak Day Served	WA/ID Served	WA/ID Unserved	WA/ID Total	WA/ID % of Peak Day Served
Expected	2012	7.23	-	7.23	100%	253.37	-	253.37	100%
Expected	2013	7.31	-	7.31	100%	257.65	-	257.65	100%
Expected	2014	7.20	-	7.20	100%	255.77	-	255.77	100%
Expected	2015	7.23	-	7.23	100%	258.58	-	258.58	100%
Expected	2016	7.29	-	7.29	100%	262.92	-	262.92	100%
Expected	2017	7.36	-	7.36	100%	267.56	-	267.56	100%
Expected	2018	7.42	-	7.42	100%	272.04	-	272.04	100%
Expected	2019	7.46	-	7.46	100%	275.59	-	275.59	100%
Expected	2020	7.50	-	7.50	100%	279.39	-	279.39	100%
Expected	2021	7.56	-	7.56	100%	283.59	-	283.59	100%
Expected	2022	7.58	-	7.58	100%	286.78	-	286.78	100%
Expected	2023	7.61	-	7.61	100%	289.92	-	289.92	100%
Expected	2024	7.64	-	7.64	100%	293.46	-	293.46	100%
Expected	2025	7.67	-	7.67	100%	296.78	-	296.78	100%
Expected	2026	7.70	-	7.70	100%	300.44	-	300.44	100%
Expected	2027	7.73	-	7.73	100%	303.38	-	303.38	100%
Expected	2028	7.76	-	7.76	100%	306.66	-	306.66	100%
Expected	2029	7.80	-	7.80	100%	309.85	-	309.85	100%
Expected	2030	7.83	-	7.83	100%	311.74	1.25	312.99	100%
Expected	2031	7.86	-	7.86	100%	311.74	4.38	316.12	98.6%

Case	Gas Year	Klamath Falls Served	Klamath Falls Unserved	Klamath Falls Total	Klamath Falls % of Peak Day Served	Medford/ Roseburg Served	Medford/ Roseburg Unserved	Medford/ Roseburg Total	Medford/ Roseburg % of Peak Day Served
Expected	2012	12.69	-	12.69	100%	67.91	-	67.91	100%
Expected	2013	12.83	-	12.83	100%	68.59	-	68.59	100%
Expected	2014	12.68	-	12.68	100%	67.90	-	67.90	100%
Expected	2015	12.79	-	12.79	100%	68.66	-	68.66	100%
Expected	2016	13.00	-	13.00	100%	69.98	-	69.98	100%
Expected	2017	13.21	-	13.21	100%	71.41	-	71.41	100%
Expected	2018	13.40	-	13.40	100%	72.81	-	72.81	100%
Expected	2019	13.55	-	13.55	100%	73.94	-	73.94	100%
Expected	2020	13.70	-	13.70	100%	75.13	-	75.13	100%
Expected	2021	13.88	-	13.88	100%	76.42	-	76.42	100%
Expected	2022	14.01	-	14.01	100%	77.53	-	77.53	100%
Expected	2023	14.13	-	14.13	100%	78.49	-	78.49	100%
Expected	2024	14.27	-	14.27	100%	79.60	-	79.60	100%
Expected	2025	14.40	-	14.40	100%	80.65	-	80.65	100%
Expected	2026	14.54	-	14.54	100%	81.80	-	81.80	100%
Expected	2027	14.65	-	14.65	100%	82.76	-	82.76	100%
Expected	2028	14.78	-	14.78	100%	83.79	-	83.79	100%
Expected	2029	14.91	-	14.91	100%	84.09	0.60	84.69	99.3%
Expected	2030	15.00	0.02	15.02	99.9%	84.08	1.46	85.54	98.3%
Expected	2031	15.00	0.14	15.14	99.1%	84.09	2.41	86.50	97.2%

NEW RESOURCE OPTIONS

When existing resources are not sufficient to meet expected demand, there are many considerations that are important in determining the appropriateness of potential resources.

RESOURCE COST

Resource cost is the primary consideration when evaluating resource options although other factors mentioned below also influence resource decisions. We have found that newly constructed resources are typically more expensive than existing resources but existing resources are in shorter supply. Newly constructed resources provided by a third party, such as a pipeline, may require a significant contractual commitment. Newly constructed resources are often less expensive per unit if a larger facility is constructed, because of economies of scale.

LEAD TIME REQUIREMENTS

New resource options can take from one to five or more years to put in service. Open season processes, planning and permitting, environmental review, design, construction and testing are some of the aspects contributing to lead time requirements for new physical facilities. Recalls of released pipeline capacity typically require advance notice of up to a year. Even DSM programs require significant time from program development and rollout to the point when natural gas savings are realized.

PEAK VERSUS BASE LOAD

Our planning efforts include the ability to serve a peak day as well as all other demand periods. Avista's core loads are considerably higher in the winter than the summer. Due to the winter-peaking nature of Avista's demand, resources that cost-effectively serve the winter without an associated summer commitment may be preferable. Alternatively, it is possible that the costs of a winter-only resource may exceed the cost of annual resources after capacity release or optimization opportunities are considered.

RESOURCE USEFULNESS

It is paramount that an available resource effectively delivers natural gas to the intended geographical region. Given Avista's unique service territories it is often impossible to deliver resources from a resource option such as storage without acquiring additional pipeline transportation. Pairing together resources increases the cost. Other key factors that can contribute to the usefulness of a resource are viability and reliability. If the potential resource is either not available currently (e.g., new technology) or not reliable on a peak day (e.g., firm) then may not be considered as an option for meeting unserved demand.

"LUMPINESS" OF RESOURCE OPTIONS

Newly constructed resource options are often "lumpy." This means that new resources may only be available in larger-than-needed quantities and only available every few years. This lumpiness of resources is driven by the cost dynamics of new construction, the fact that lower unit costs are available with larger expansions and the economics of expansion of existing pipelines or the construction of new resources dictate additions infrequently. Lumpiness provides a cushion for future growth. Given the economies of scale for pipeline construction, we are afforded the opportunity to secure resources to serve future demand increases.

COMPETITION

LDCs, end-users and marketers all compete for regional resources. The Northwest has been particularly efficient in the utilization of existing resources, which means the system is neither overbuilt nor under built.

Currently, the region is able to sufficiently handle the demand needs of varying parties. However, the future needs vary and regional LDCs may find they are competing with each other and other parties in order to secure firm resources for customers.

RISKS AND UNCERTAINTIES

Investigation, identification and assessment of risks and uncertainties are critical considerations when evaluating supply resource options. For example, resource costs determinations are subject to various degrees of estimation, partly influenced by the expected timeframe of the resource need and degree of rigor determining estimates or estimation difficulties because of the uniqueness of a resource. Lead times can have varying degrees of certainty ranging from securing currently available transport (high certainty) to building in service territory underground storage (low certainty).

RESOURCE SELECTION

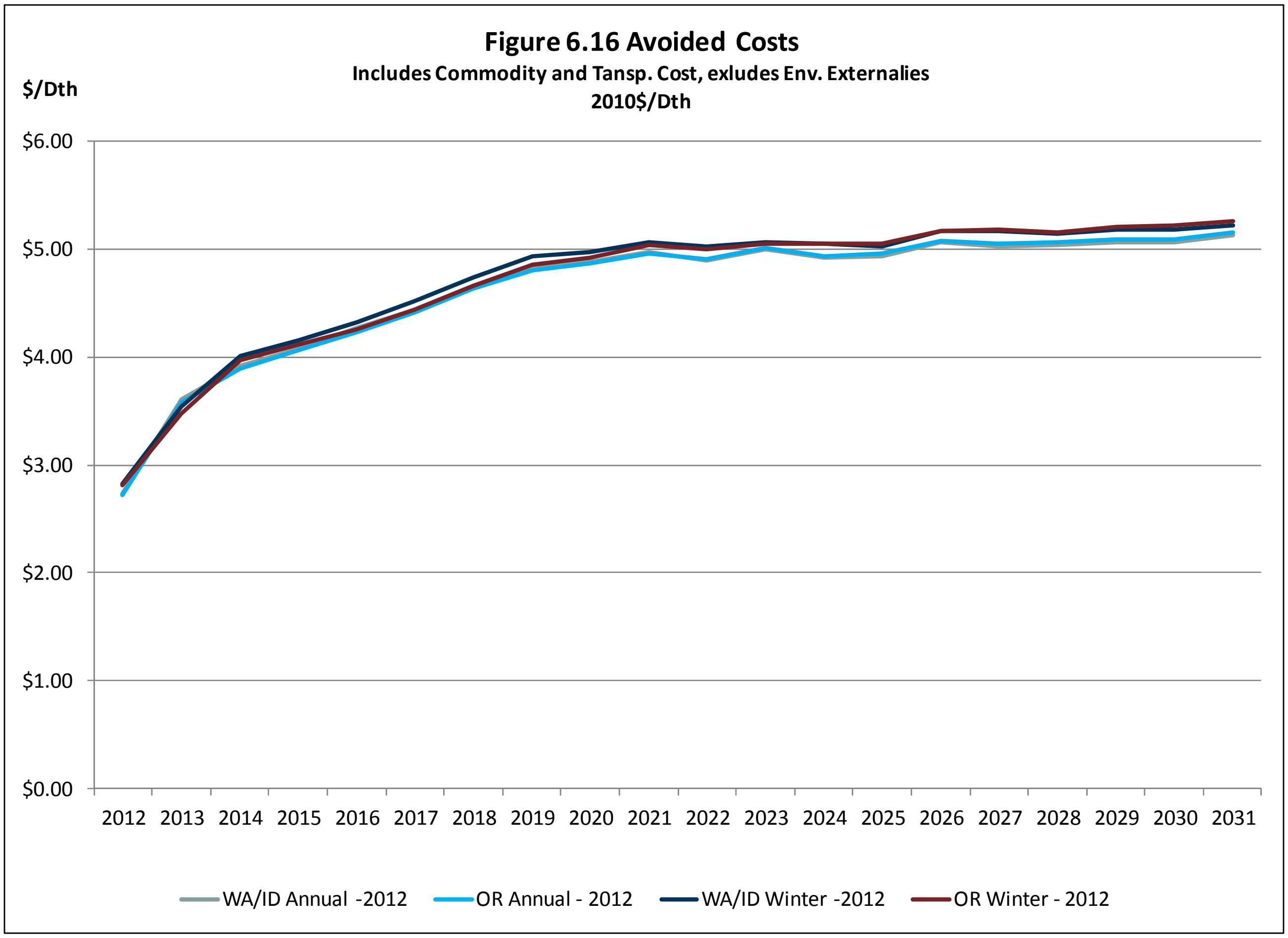
After identifying supply-side resource options and evaluating them based on the above considerations, we entered these supply-side scenarios (see Table 5.2) along with conservation measures (see Chapter 4 - Demand-side Resources) into the SENDOUT® model for it to select the least cost approach to meeting resource deficiencies. SENDOUT® compares demand-side and supply-side resources (see Appendix 6.3 for a list of supply-side resource options) using PVRR analysis to determine which resource is the best risk adjusted/least cost resource.

DEMAND-SIDE RESOURCES

AVOIDED COST

The SENDOUT® model determined avoided cost figures represent the unit cost to serve the next unit of demand with a supply-side resource option during a given period. If a conservation measure's total resource cost is less than this avoided cost, it will cost effectively reduce customer demand and Avista can "avoid" possible commodity, storage, transportation and other supply resource costs.

SENDOUT® calculates marginal cost data by day, month and year for each demand area. A summarized graphical depiction of avoided annual and winter costs for the Washington/Idaho and Oregon areas is in Figure 6.16. The detailed data is presented in Appendix 6.4. The avoided costs do not include environmental externality adders to monetarily recognize adverse environmental impacts. Appendix 4.2 discusses this concept more fully and includes specific requirements required in our Oregon service territory.



SELECTED MEASURES

Using the above avoided cost thresholds; SENDOUT® selected all DSM potential. Table 6.4 details the potential DSM savings in each region from the selected conservation potential for our Expected Case.

Table 6.4 Annual, Annual Average and Peak Day Demand Served by DSM

Case	Gas Year	Annual Klamath DSM (Dth)	Daily Klamath DSM (Dth/day)	Peak Day Klamath DSM (Dth/day)	Annual La Grande DSM (Dth)	Daily La Grande DSM (Dth/day)	Peak Day La Grande DSM (Dth/day)	Annual Medford/ Roseburg DSM (Dth)	Daily Medford/ Roseburg DSM (Dth/day)	Peak Day Medford/ Roseburg DSM (Dth/day)
Expected	2012	3.804	0.010	0.041	1.125	0.003	0.017	17.318	0.047	0.218
Expected	2013	9.197	0.025	0.085	3.762	0.010	0.036	39.691	0.109	0.456
Expected	2014	17.066	0.047	0.152	7.479	0.020	0.064	73.108	0.200	0.797
Expected	2015	28.448	0.078	0.249	12.841	0.035	0.104	121.001	0.332	1.295
Expected	2016	43.646	0.120	0.377	19.585	0.054	0.157	184.206	0.505	1.938
Expected	2017	61.501	0.168	0.530	27.493	0.075	0.221	258.310	0.708	2.703
Expected	2018	80.223	0.220	0.690	35.789	0.098	0.286	336.087	0.921	3.517
Expected	2019	98.644	0.270	0.853	43.949	0.120	0.354	412.643	1.131	4.334
Expected	2020	117.151	0.321	1.015	52.118	0.143	0.421	489.317	1.341	5.158
Expected	2021	127.102	0.348	1.111	56.567	0.155	0.460	531.201	1.455	5.649
Expected	2022	137.231	0.376	1.205	61.086	0.167	0.499	573.753	1.572	6.132
Expected	2023	148.183	0.406	1.308	65.943	0.181	0.542	619.449	1.697	6.663
Expected	2024	162.586	0.445	1.442	72.437	0.198	0.597	680.881	1.865	7.362
Expected	2025	175.765	0.482	1.567	78.308	0.215	0.651	736.135	2.017	8.025
Expected	2026	189.001	0.518	1.691	84.187	0.231	0.701	791.406	2.168	8.633
Expected	2027	200.574	0.550	1.788	89.385	0.245	0.743	840.303	2.302	9.160
Expected	2028	212.097	0.581	1.881	94.588	0.259	0.783	889.359	2.437	9.620
Expected	2029	221.425	0.607	1.962	98.711	0.270	0.817	927.903	2.542	10.060
Expected	2030	231.638	0.635	2.050	103.227	0.283	0.853	970.169	2.658	10.492
Expected	2031	242.347	0.664	2.141	107.971	0.296	0.890	1,014.565	2.780	10.937

Case	Gas Year	Annual Oregon DSM (Dth)	Daily Oregon DSM (Dth/day)	Peak Day Oregon DSM (Dth/day)	Annual WA/ID DSM (Dth)	Daily WA/ID DSM (Dth/day)	Peak Day WA/ID DSM (Dth/day)	Annual Total System DSM (Dth)	Daily Total System DSM (Dth/day)	Peak Day Total System DSM (Dth/day)
Expected	2012	22.247	0.061	0.275	116.058	0.318	1.198	138.305	0.379	1.474
Expected	2013	52.650	0.144	0.577	244.960	0.671	2.432	297.610	0.815	3.009
Expected	2014	97.653	0.268	1.013	425.533	1.166	4.149	523.186	1.433	5.162
Expected	2015	162.291	0.445	1.648	631.464	1.730	5.994	793.755	2.175	7.642
Expected	2016	247.438	0.678	2.472	869.181	2.381	7.975	1,116.619	3.059	10.447
Expected	2017	347.304	0.952	3.454	1,102.398	3.020	10.193	1,449.702	3.972	13.647
Expected	2018	452.098	1.239	4.493	1,333.820	3.654	12.440	1,785.918	4.893	16.934
Expected	2019	555.236	1.521	5.540	1,570.968	4.304	14.837	2,126.204	5.825	20.377
Expected	2020	658.587	1.804	6.594	1,818.742	4.983	17.303	2,477.328	6.787	23.897
Expected	2021	714.870	1.959	7.220	2,060.492	5.645	19.892	2,775.361	7.604	27.112
Expected	2022	772.070	2.115	7.836	2,260.822	6.194	21.888	3,032.892	8.309	29.724
Expected	2023	833.575	2.284	8.513	2,453.430	6.722	23.941	3,287.005	9.005	32.454
Expected	2024	915.904	2.509	9.402	2,661.143	7.291	25.837	3,577.047	9.800	35.240
Expected	2025	990.208	2.713	10.243	2,855.741	7.824	27.887	3,845.949	10.537	38.130
Expected	2026	1,064.594	2.917	11.025	3,052.666	8.363	29.847	4,117.260	11.280	40.872
Expected	2027	1,130.262	3.097	11.692	3,251.635	8.909	31.865	4,381.898	12.005	43.556
Expected	2028	1,196.045	3.277	12.284	3,469.294	9.505	33.928	4,665.338	12.782	46.212
Expected	2029	1,248.039	3.419	12.839	3,617.612	9.911	35.500	4,865.651	13.331	48.339
Expected	2030	1,305.035	3.575	13.395	3,779.664	10.355	36.994	5,084.699	13.931	50.390
Expected	2031	1,364.884	3.739	13.968	3,928.219	10.762	38.536	5,293.102	14.502	52.504

DSM ACQUISITION GOALS

The avoided cost established in SENDOUT®, the demand-side potential selected and the resulting calculated therm savings is the basis for determining DSM acquisition goals and subsequent program implementation planning. While the model selected essentially all DSM potential, the subsequent business planning process yielded different results. Chapter 4 – Demand-Side Resources has additional details on this process.

SUPPLY-SIDE RESOURCES

SENDOUT® considered all options entered into the model, determined when and what resources were needed and rejected options that were determined to not be cost effective. These selected resources represent the least cost solution, within given constraints, to serve anticipated customer requirements. Table 6.5 shows the SENDOUT® selected supply-side resources for the Expected Case.

Table 6.5 Supply Side Resource Selected in SENDOUT®

Case	Additional Resources	Jurisdiction	Size	Cost/Rates	Availability	Notes
Expected Case						
	GTN Capacity	WA/ID	25,000 Dth/d	GTN rate	Currently	Currently available unsubscribed capacity.
	GTN Medford Lateral Expansion	OR	10,000 Dth/d	GTN rate	2014	Additional compression to allow more gas to flow from GTN mainline to the lateral.
	Malin Backhaul	OR	10,000 Dth/d	GTN rate	Currently	Backhaul capacity is provided by tarrif. In order to facilitate additional deliveries to our OR properties an expansion of the Medford Lateral is necessary.
	Klamath Falls Lateral Purchase	OR	15,000 Dth/d	Net Book Value	12/31/2012	Purchase of the NWP Klamath Falls Lateral. This was the perferred resource identified in the 2009 IRP.
	GTN Capacity	OR	2,000 Dth/d	GTN rate	Currently	Currently available unsubscribed capacity.

With additional research and investigation, we may later determine that alternative resources are more cost effective than those resources selected in this IRP. Since resource additions are not anticipated until late in the planning horizon, we will continue to review and refine knowledge of resource options and will act to secure these best cost/risk options when necessary or advantageous.

RESOURCE SELECTION RESULTS

Figures 6.17 through 6.19 summarize modeling results when comparing regional peak day demand against existing and incremental resources for the Expected Case over the 20-year planning period.

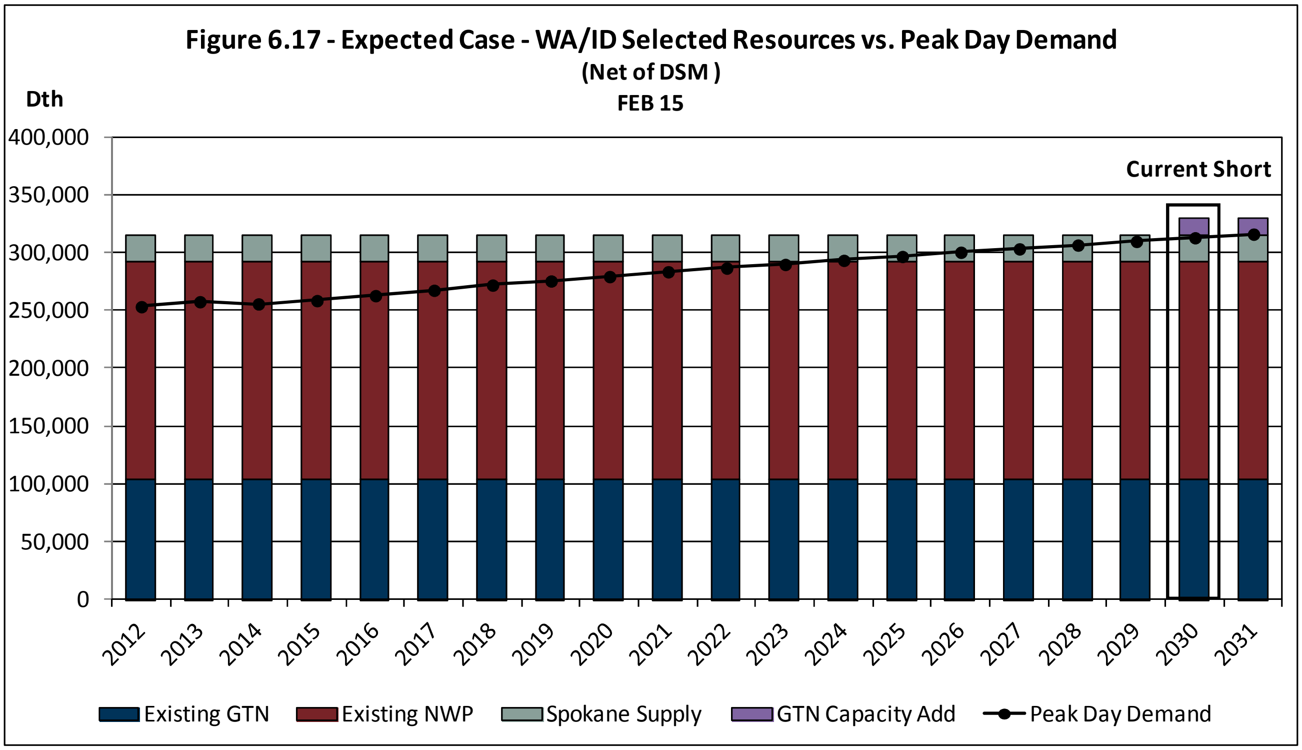


Figure 6.17 - Expected Case - WA/ID Selected Resources vs. Peak Day Demand
(Net of DSM)
FEB 15
Dth
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Existing GTN
Existing NWP
Spokane Supply
GTN Capacity Add
Peak Day Demand

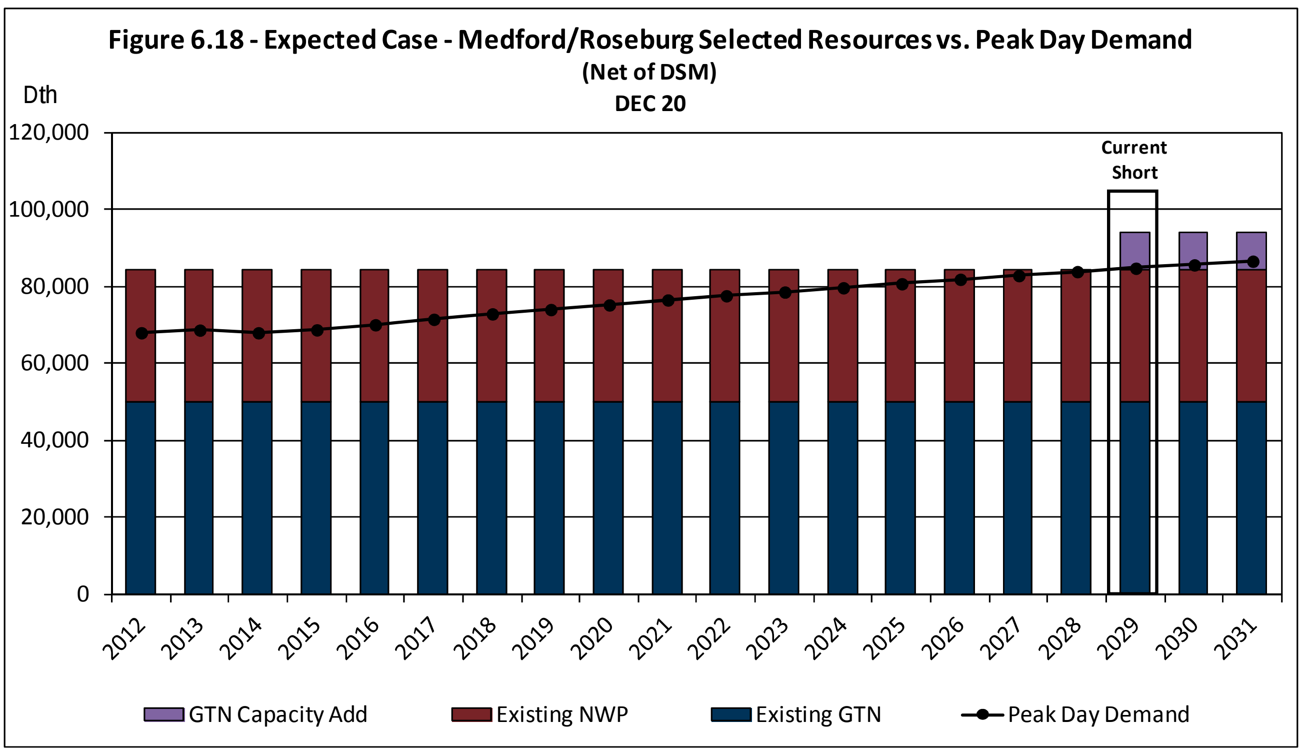
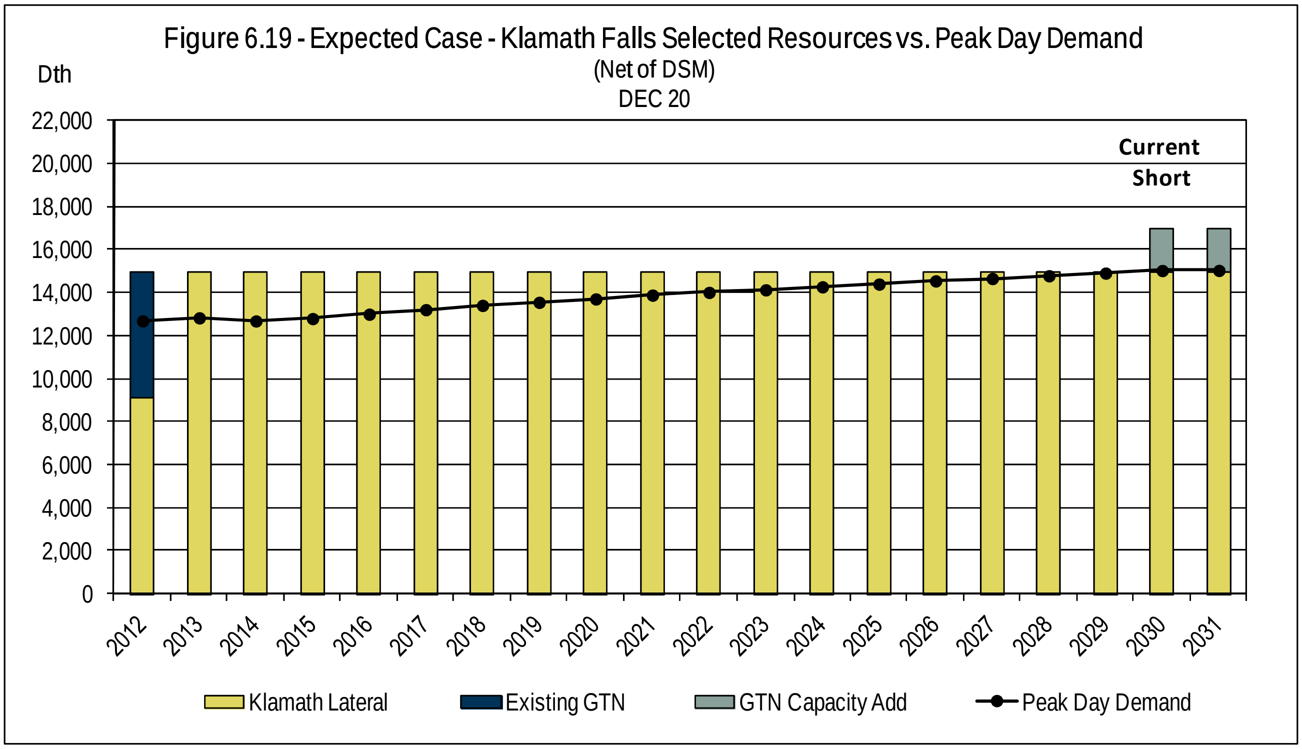


Figure 6.18 - Expected Case - Medford/Roseburg Selected Resources vs. Peak Day Demand
(Net of DSM)
DEC 20
Dth
120,000
100,000
80,000
60,000
40,000
20,000
0
Current Short
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
GTN Capacity Add
Existing NWP
Existing GTN
Peak Day Demand



As indicated in the figures, after DSM savings the model shows a general preference for incremental transportation resources from existing pipelines and supply basins to resolve capacity deficiencies.

RESOURCE UTILIZATION

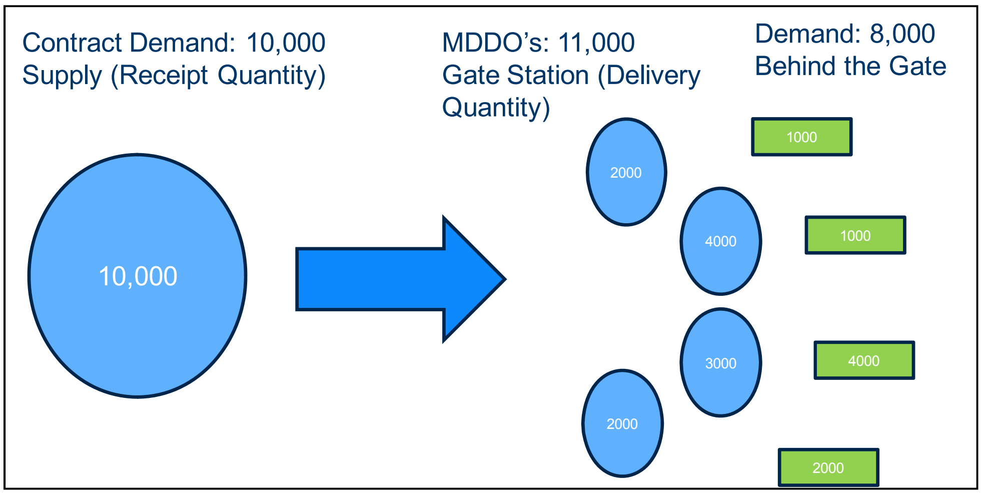
Our primary purpose is to meet our customer's demand needs in a cost effective manner. As the analysis indicates, we have ample resources to meet highly variable demand under multiple scenarios, including peak weather events, for the foreseeable future. With primary needs addressed, utilization of excess resource capacity is considered. There are many short term and long term opportunities to utilize and capture value for our customers using these resources. Each year a comprehensive evaluation of our demand forecasts and existing resource portfolio are reviewed. The following are some examples of how resources can be utilized:

- Serving interruptible demand
- Storage injections
- Storage optimization
- Capacity releases – short-term and long-term
- Basin optimization
- Transportation optimization
- Intra and/or inter-seasonal optimization

GATE STATION ANALYSIS

In previous IRP's we identified a risk associated with our aggregated methodology for supply and demand forecasting. Our forecasting methodology is consistent with operational practices which aggregate capacity at individual points for scheduling/nomination purposes. Typically, the amount of natural gas that can flow from a contract demand (CD) (i.e. receipt/supply quantity) is fixed and the amount that can be delivered (i.e. maximum daily delivery obligation (MDDO) or delivery quantity) to various gate stations is greater. (See Figure 6.20) However, aggregation could mask deficiencies at individual gate stations.

Figure 6.20 – Gate Station Modeling Challenge



In order to address this concern, a gate by gate analysis was developed outside of SENDOUT®. The analysis involved coordination between Gas Supply, Gas Engineering, and intrastate pipeline personnel. Utilizing historical gate station flow data and demand forecasting methodologies detailed in our IRP, forecasted peak day gate station demand was calculated. This demand was then compared to contracted and operational capacities at each gate station.

If forecasted demand exceeded contracted and/or operational capacities further analysis is completed. The additional analysis would involve assessing the most economic way to address the gate deficiency. This could involve a gate station expansion, re-assigning MDDO's, targeted DSM, or distribution system enhancements.

For example, the analysis identified a gate station on NWP's Coeur d'Alene Lateral where forecasted peak day demand exceeded both the gate station MDDO's and physical capacity. Working together with all parties, numerous solutions were examined. Current analysis indicates the optimal solution is to take advantage of a pre-existing plan to build a new gate station at Chase Road off of GTN's mainline (See Chapter 8 for further details). The project originally was designed to alleviate capacity constraints at GTN's Rathdrum gate, however, the new gate's location allows for the potential to displace gas on the NWP Coeur d'Alene Lateral.

|| ACTION ITEM

With no immediate need to acquire incremental supply side resources to meet peak day demands Avista's focus in the near term will include the following:

- Continuing to coordinate analytic efforts between Gas Supply, Gas Engineering, and the intrastate pipelines to perform gate station analysis and if deficiencies are identified seek least cost solutions.

CONCLUSION

The integrated resource portfolio analysis process summarized in this chapter was first performed on our Average Case and then on the Expected Case demand scenario. We have chosen to utilize the Expected Case for our peak operational planning activities because this case is the most likely outcome given our experience, industry knowledge and our understanding of future natural gas markets. This case provides for reasonable demand growth given current expectations of natural gas prices over the planning horizon. If realized, this case is at a level that allows us to be well protected against resource shortages and does not over commit to additional long-term resources.

We fully recognize that there are numerous other potential outcomes. The process described in this chapter was applied to alternate demand and supply resource scenarios, which is covered in the Chapter 7 – Alternate Scenarios, Portfolios and Stochastic Analysis.

CHAPTER 7 ALTERNATE SCENARIOS, PORTFOLIOS AND STOCHASTIC ANALYSIS

OVERVIEW

The integrated resource portfolio analysis process described in Chapter 6 was applied to several alternate demand and supply resource scenarios to develop a sufficient range of possible alternate portfolios. This deterministic modeling approach considered a host of underlying assumptions which were vetted with significant discussion and recommendations from our TAC to develop a consensus number of cases to model and analyze.

We also performed stochastic modeling for estimating probability distributions of potential outcomes by allowing for random variation in natural gas prices and weather based on fluctuations observed in historical data. This statistical analysis, in conjunction with our deterministic analysis, enabled us to statistically quantify the risk from a reliability and cost perspective related to resource portfolios under varying price and weather environments.

ALTERNATE DEMAND SCENARIOS

As discussed in the Demand Forecasting section, we have identified several alternate scenarios for detailed analysis to capture a wide range of possible outcomes over the planning horizon. These scenarios are summarized in Table 7.1 and are described in detail in the Chapter 3 - Demand Forecasts and Appendices 3.6 and 3.7. These alternate scenarios consider different demand influencing factors as well as price elasticity effects for various price influencing factors.

Table 7.1 Demand Scenarios
Average Case
Expected Case
High Growth/Low Price
Low Growth/High Price
Alternate Weather Standard

Demand profiles over the planning horizon for each of the alternate scenarios shown in Figures 7.1 and 7.2 reflect the two winter peaks we model for the different service territories (Dec. 20 and Feb. 15).

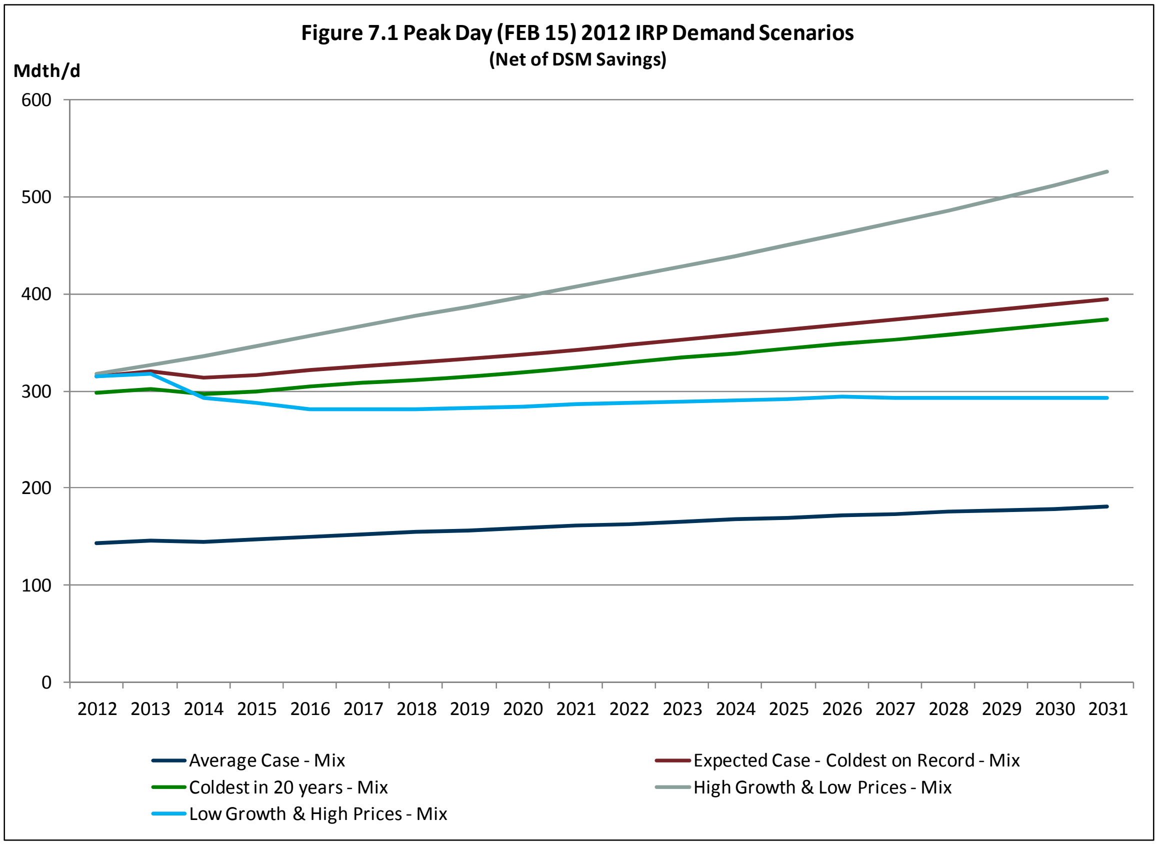


Figure 7.1 Peak Day (FEB 15) 2012 IRP Demand Scenarios
(Net of DSM Savings)
Mdth/d
600
500
400
300
200
100
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Average Case - Mix
Expected Case - Coldest on Record - Mix
Coldest in 20 years - Mix
High Growth & Low Prices - Mix
Low Growth & High Prices - Mix

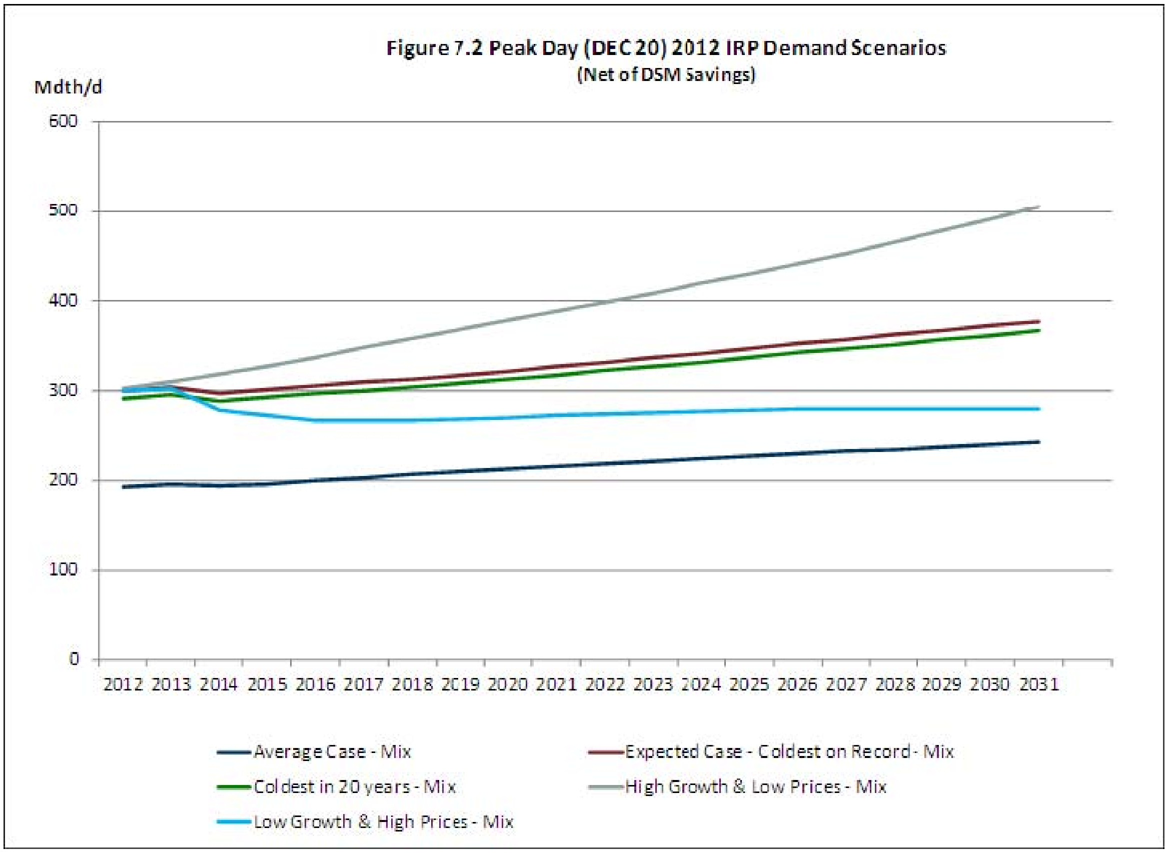
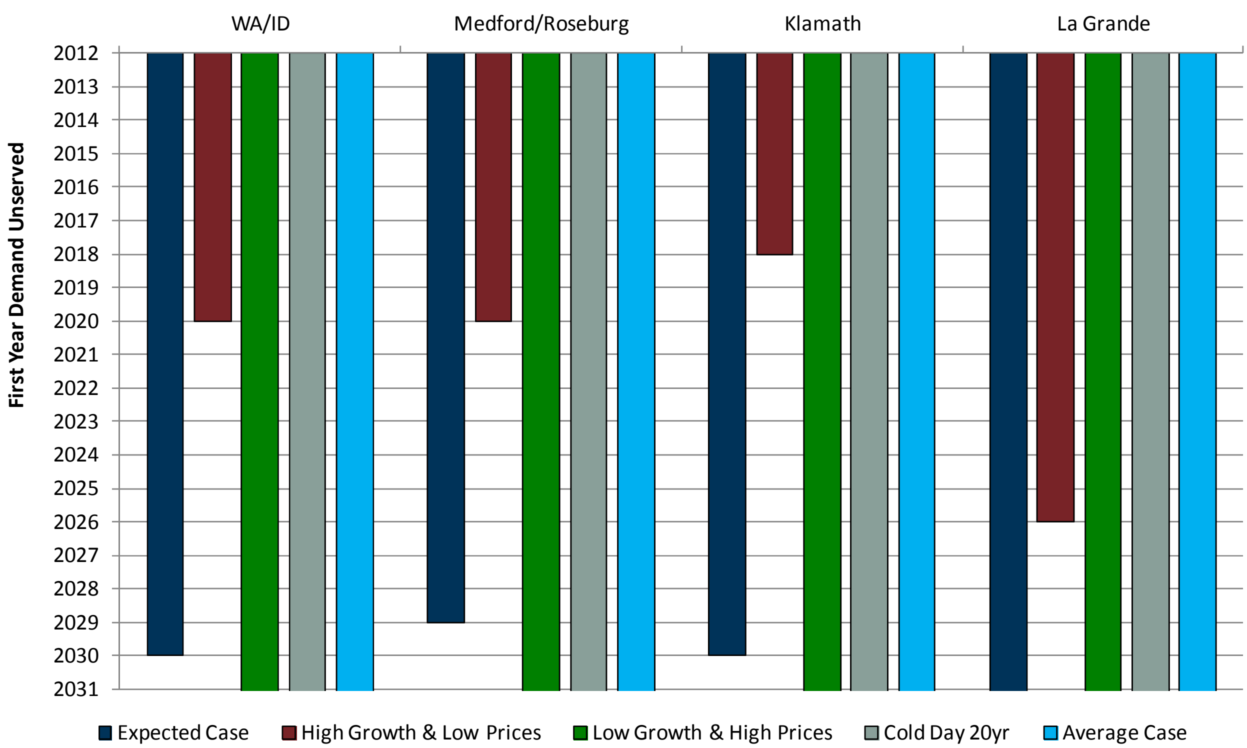


Figure 7.2 Peak Day (DEC 20) 2012 IRP Demand Scenarios
(Net of DSM Savings)
Mdth/d
600
500
400
300
200
100
0
2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031
Average Case - Mix
Expected Case - Coldest on Record - Mix
Coldest in 20 years - Mix
High Growth & Low Prices - Mix
Low Growth & High Prices - Mix

As in the Expected Case, we modeled in SENDOUT® the same resource integration and optimization process described in this section for each of the other five demand scenarios (see Appendix 3.7 for a complete listing of all portfolios considered). This identified first year unserved dates for each scenario by service territory (Figure 7.3).

Figure 7.3 - First Year Peak Demand Not Met with Existing Resources
Scenario Comparisons



As anticipated, our High Growth, Low Price scenario has the most rapid growth and the earliest first year unserved dates. This scenario includes customer growth rates 60% higher than the Expected Case, incremental demand driven by NGV/CNG vehicles, and no adjustment for price elasticity. Even with these aggressive assumptions, resource shortages do not occur until late in the planning horizon.

- 2020 in Washington/Idaho
- 2020 in Medford/Roseburg
- 2018 in Klamath
- 2026 in La Grande

This "steeper" demand highlights the "flat demand risk" discussed earlier. The likelihood of this scenarios occurrence is remote; however any potential for accelerated unserved dates warrants close monitoring of demand trends and resource lead times.

The remaining scenarios do not identify any resource deficiencies in the planning horizon.

Detailed information on certain selected scenarios is included in the following appendices:

- Demand and Selected Resources graphs by service territory (High Growth Case only) – Appendix 7.1
- Peak Day Demand, Served and Unserved table (all cases) – Appendix 7.2
- Avoided cost curve detail and graphs for High Growth and Low Growth cases – Appendix 6.4

ALTERNATE SUPPLY SCENARIOS

We identified many supply-side resources which could be considered to meet resource deficiencies should they occur. Chapter 6 details available supply-side resource options that were considered for this IRP. The list includes resources we considered but did not input into SENDOUT® because of various restrictions.

For example, contracted city gate deliveries in the form of a structured purchase transaction could be a viable and desirable option to meet peak conditions. However, the market-based price and other terms are difficult to reliably determine until a formal agreement is negotiated. Exchange agreements also have market-based terms and are hard to reliably model especially when the resource is not needed in the near term.

Exported LNG was also a considered primarily as a price influencing factor. However, if one of the proposed export LNG terminals in Oregon were to be approved and a pipeline was to be built to supply that facility it potentially could bring supply through Avista's service territory. This scenario is interesting however; there is much uncertainty about export LNG. New pipeline builds are expensive and there are currently existing pipeline options that would be more cost effective. We will continue to monitor this situation and will consider inclusion of this supply scenario for future IRPs.

For our Washington/Idaho and Medford/Roseburg service territories unsubscribed firm capacity on GTN and/or firm backhaul plus lateral expansion is a preferred resource selection from our existing resources plus currently available supply scenario for most demand scenarios. However, assumptions on future availability could change over time. Therefore, we ran an additional alternate supply-side scenario with changed assumptions on GTN capacity as per Table 7.2.

Table 7.2 Supply Scenarios
Existing Resources
Existing + Expected Available
GTN Fully Subscribed

In our alternate supply scenario we assumed increased need for GTN capacity. This could be driven by power generators who require firm transportation to fuel combustion turbines or significant investments made by the transportation industry for fueling long haul trucks. The increased contracting leads to GTN becoming fully subscribed. The result of this scenario using our Expected Case demand profile is that in Washington and Idaho and Oregon recalls of existing capacity and satellite LNG is selected as the preferred resource portfolio. (Figures detailing the resources selected based on this scenario are included in Appendix 7.1.)

PORTFOLIO SELECTION

The alternate demand scenarios and supply scenarios are matched together to form portfolios. Each of these unique portfolios is run through SENDOUT® where the supply resources and demand-side resources are compared and selected on a least cost basis. Once the resources are determined, a net present value of the revenue requirement (PVRR) is calculated.

In the Expected Case, the Expected Demand with Existing Resources plus Expected Available portfolio has the lowest PVRR and was therefore selected as our preferred portfolio. In this portfolio, the supply-side resources selected to meet unserved demand include the acquisition of currently available pipeline capacity on GTN, additional compression and capacity on the GTN Medford Lateral. These resources are the least cost/risk adjusted options currently available to meet peak day demand.

Table 7.3 summarizes the PVRR of all the portfolios considered. Each of these portfolios is based on unique assumptions and therefore a simple comparison of PVRR cannot be made.

Table 7.3 Net Present Value of Revenue Requirement (PVRR) by Portfolio

	Portfolio	Unserved Demand	PVRR in (000's)
Average Case	Average Demand with Existing Resources (before resource additions)	No	$ 5,826,401
Expected Case			
	Expected Demand with Existing Resources (before resource additions)	Yes	$ 5,902,214
	Expected Demand with Existing Resources plus Expected Available	No	$ 5,972,641
	Expected Demand with GTN Fully Subscribed	No	$ 6,245,354
Additional Demand Scenarios			
	High Growth, Low Price Demand with Existing Resources	Yes	$ 6,315,432
	High Growth, Low Price Demand with Existing Resource plus Expected Available	No	$ 6,645,781
	High Growth, Low Price Demand with GTN Fully Subscribed	No	$ 6,954,112
	Alternate Weather Standard Demand with Existing Resources	No	$ 5,888,614
	Low Growth, High Price with Existing Resources	No	$ 8,281,177

STOCHASTIC ANALYSIS[1]

The scenario (deterministic) analysis described earlier in this document represents specific “what if” situations based on predetermined assumptions including price and weather. These two factors are an integral part of scenario analysis. To better understand a particular portfolio’s response to price and weather, we applied stochastic analysis to generate a wide variety of price and weather events.

Deterministic analysis is a valuable tool for selecting the optimal portfolio. The model selects resources to meet peak weather conditions in each of the 20 years. However, due to the recurrence of design conditions in each of the 20 years, total system costs over the planning horizon can be overstated because of annual recurrence of design conditions and the recurrence of price increases in the forward price curve. As a result, deterministic analysis does not provide a comprehensive look at future events. This type of analysis is only one piece of the puzzle. Utilizing Monte Carlo simulation in conjunction with deterministic analysis provides a more complete picture of how the portfolio performs under multiple weather and price profiles.

For this IRP, Monte Carlo analysis was employed in two ways. The first was to test our weather planning standard and the second was to assess the risk related to costs of our Expected portfolio under varying price environments.

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[1] SENDOUT® uses Monte Carlo simulation to support stochastic analysis, which is a mathematical technique for evaluating risk and uncertainty. Monte Carlo simulation is a statistical modeling method used to imitate the many future possibilities that exist with a real-life system.

WEATHER

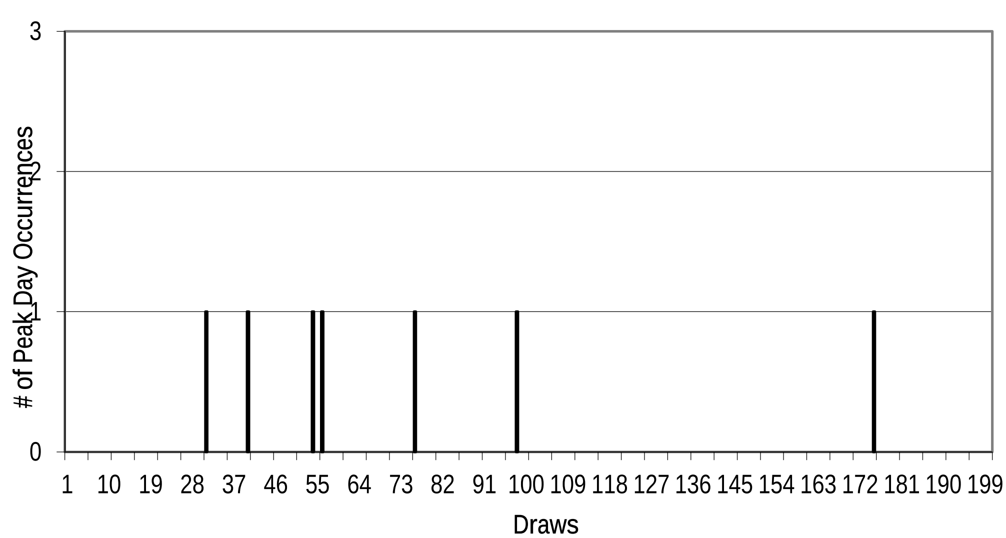
In order to evaluate weather and its effect on our portfolio we derived 200 simulations (draws) through the use of SENDOUT®'s Monte Carlo capabilities. Unlike deterministic scenarios or sensitivities the draws have more variability from month-to-month and year-to-year. In the model, random monthly total HDD draw values (subject to Monte Carlo parameters – see Table 7.4) are distributed on a daily basis for a month in history with similar HDD totals. The resulting draws provide a weather pattern with variability in the total HDD values, as well as variability in the shape of the weather pattern. This provides more robust basis for stress testing the deterministic analysis.

Table 7.4 Example of Monte Carlo Weather Inputs
Spokane

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
HDD Mean	895	1,152	1,145	913	781	546	331	143	37	37	191	544
HDD Std Dev	132	141	159	115	85	73	72	52	28	28	77	70
HDD Max	1,361	1,506	1,681	1,204	953	694	471	248	151	97	343	677
HDD Min	699	918	897	716	598	392	192	61	-	1	54	361

Avista models five weather areas: Spokane, Medford, Roseburg, Klamath Falls and La Grande. From the simulation data we were able to assess the frequency that the peak day occurs in each area. The stochastic analysis shows that in over 200 twenty-year simulations, while still remote, peak day (or more) does occur with enough frequency to maintain our current planning standard for this IRP though this topic remains a subject of continued analysis. For example, in our Medford weather pattern over the 200 twenty-year draws (i.e. 4000 years, HDDs at or above peak weather (61 HDD) occur 128 times. This equates to a peak day occurrence once every 31 years (4000 simulation years divided by 128 occurrences). The Spokane area has the least occurrences of peak day (or more) occurrences in our simulations while La Grande has the most occurrences. This is primarily due to the frequency in which each region's peak day HDD occurs within the historical data as well as near peak day HDDs. See Figures 7.9 through 7.13 for the number of peak day occurrences for a weather area.

Figure 7.4 - Frequency of Peak Day Occurrences
Spokane



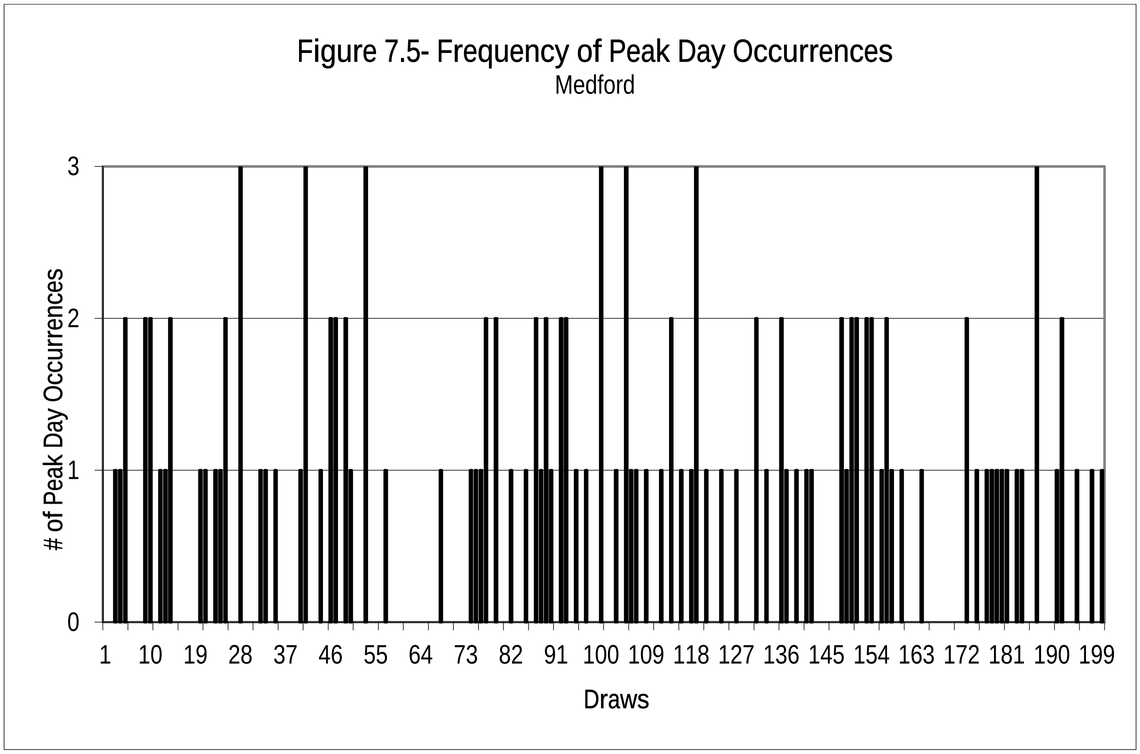


Figure 7.5- Frequency of Peak Day Occurrences
Medford
# of Peak Day Occurrences
3
2
1
0
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws

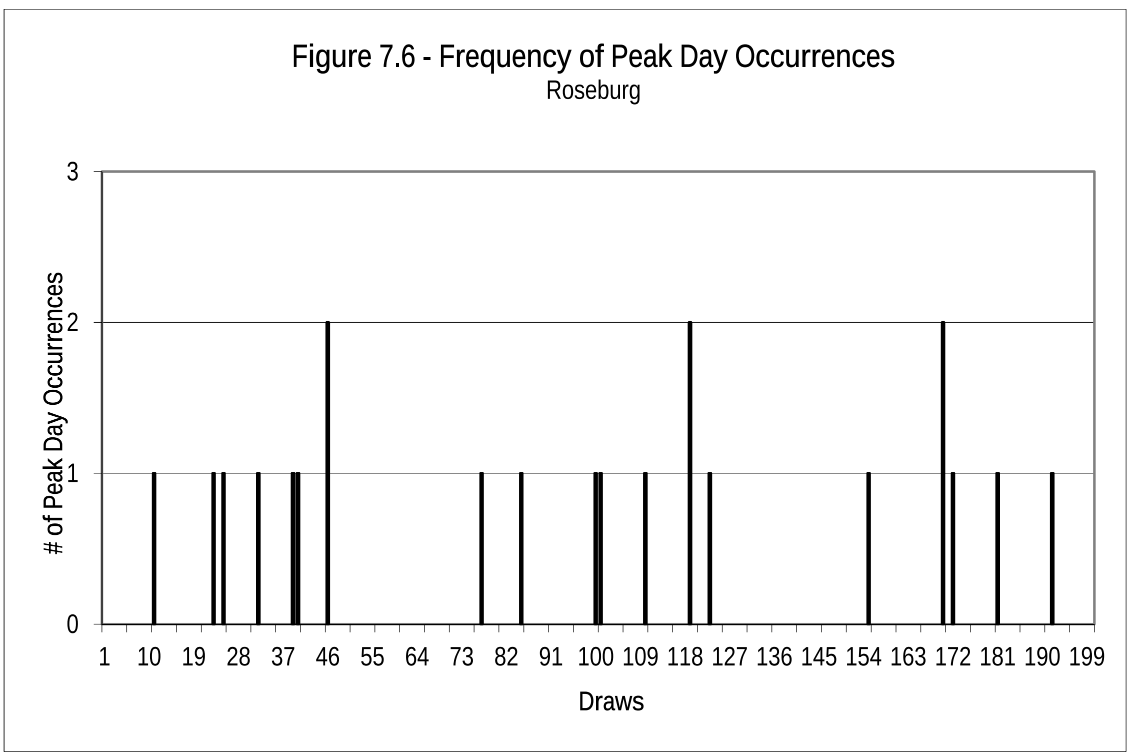
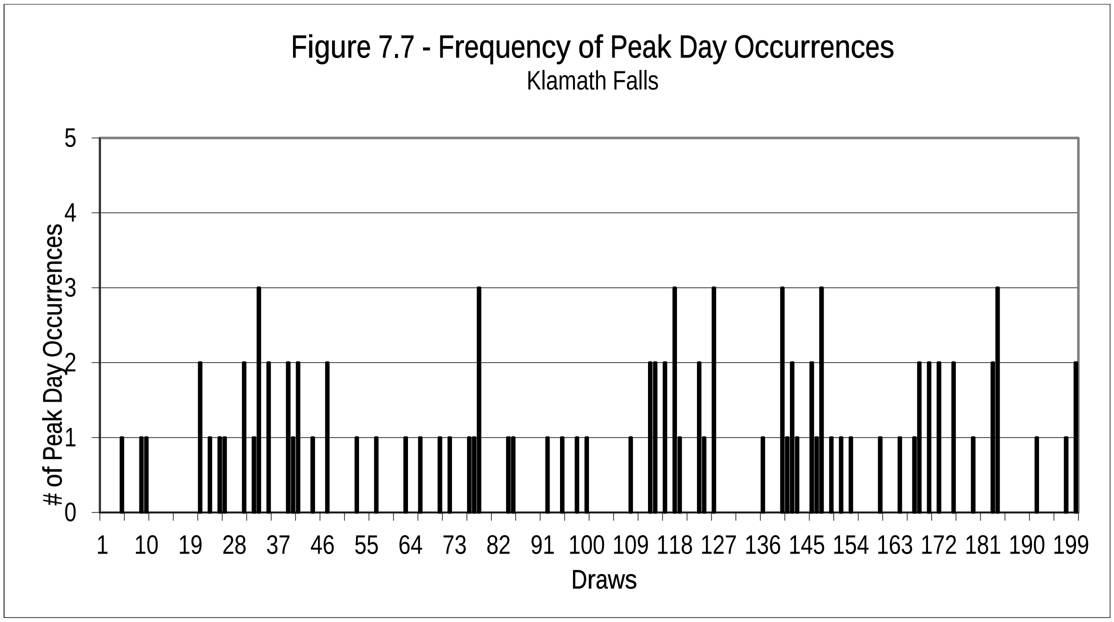
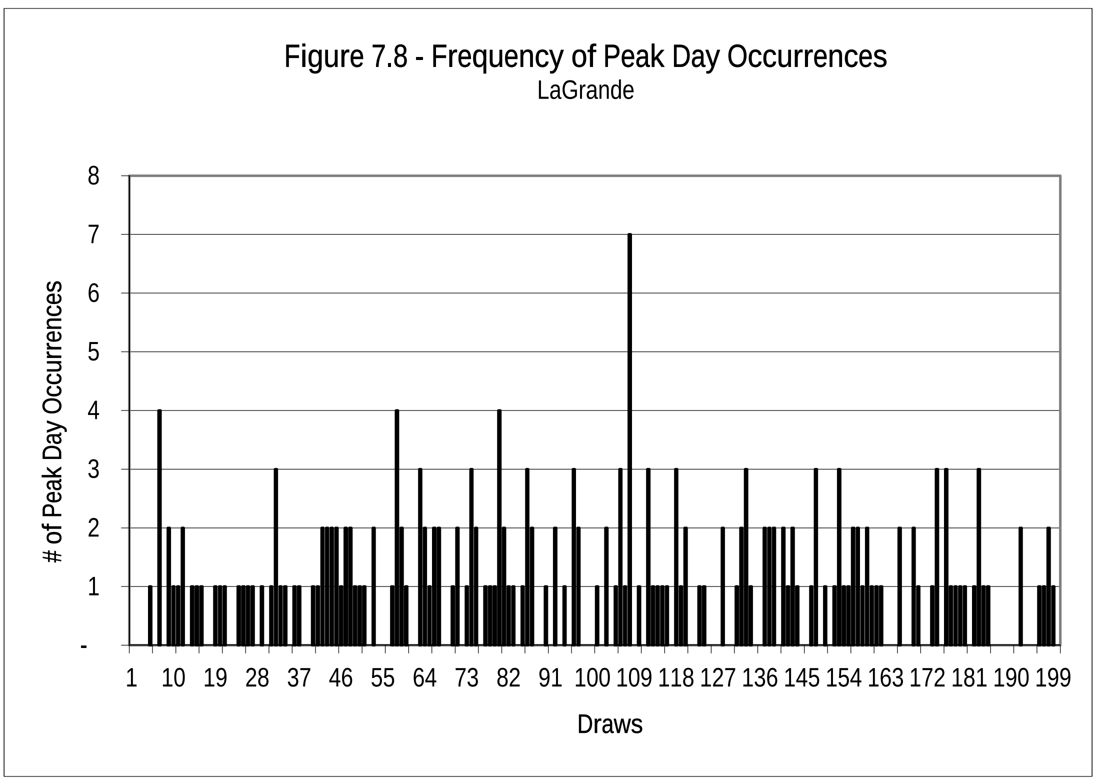


Figure 7.6 - Frequency of Peak Day Occurrences
Roseburg
# of Peak Day Occurrences
3
2
1
0
1 10 19 28 37 46 55 64 73 82 91 100 109 118 127 136 145 154 163 172 181 190 199
Draws



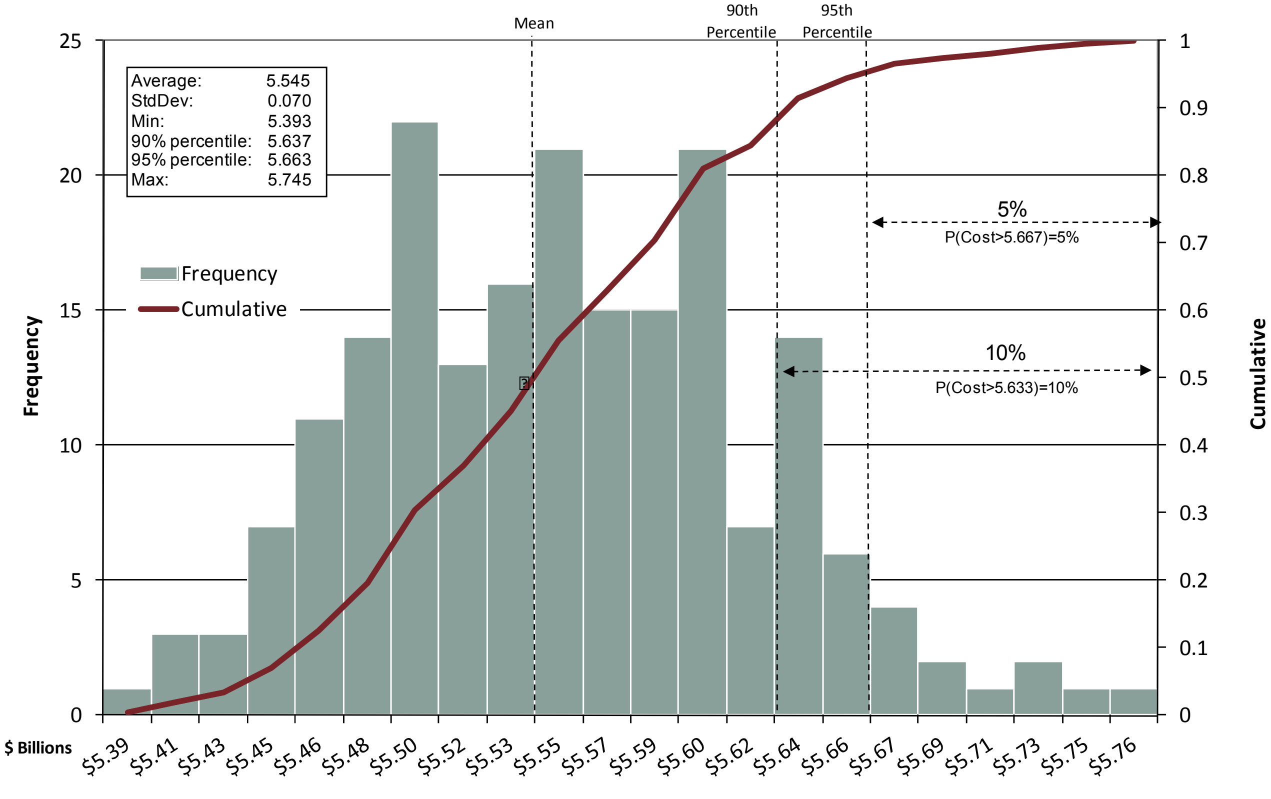


PRICE

While weather is an important driver for IRP planning price is also important. As seen in recent years, there can be significant price volatility that can affect the portfolio. In deterministic modeling a single price curve for each scenario is used to perform analysis. There is risk, however, that the price curve used in the scenario will not reflect actual results.

Through Monte Carlo simulation we are able to test our portfolio and quantify the risk to our customers when prices do not materialize as forecasted. We performed a simulation of 200 draws, varying prices, to investigate whether the Expected Case total portfolio costs from our deterministic analysis is within the range of occurrences in our stochastic analysis. Figure 7.9 shows a histogram of the total portfolio cost of all 200 draws plus the Expected Case results. This histogram depicts the frequency and the total cost of the portfolio among all the draws, the mean of the draws, the standard deviation of the total costs and the total costs from the Expected Case. The figure confirms that our Expected Case total portfolio cost is within an acceptable range of total portfolio costs based on 200 unique pricing scenarios.

Figure 7.9
Avista IRP Total 20-Year Cost



Performing stochastic analysis on two key variables of weather and price in our demand analysis provided a statistically supported approach to evaluate and confirm the findings reached from our scenario analysis with respect to adequacy and reasonableness of our weather planning standard and our selected natural gas price forecast. This alternative analytical perspective provides us better confidence in our conclusions and helps us stress test our assumption, thereby mitigating analytical risks.

REGULATORY REQUIREMENTS

IRP regulatory requirements in Washington, Oregon and Idaho call for several key components. The completed plan must demonstrate that we have:

- Examined a range of demand forecasts
- Examined feasible means of meeting demand with both supply-side and demand-side resources
- Treated supply-side and demand-side resources equally

- Described our long-term plan for meeting expected demand growth
- Described our plan for resource acquisitions between planning cycles
- Taken planning uncertainties into consideration
- Involved the public in the planning process
- We have addressed the applicable requirements throughout this document. Appendix 2.2 lists the specific requirements and guidelines of each jurisdiction and describes our compliance in detail

We are also required to consider risks and uncertainties throughout our planning and analysis. Our approach in addressing this requirement was to identify factors that could cause significant deviation from our Expected Case planning conclusions. We employed dynamic demand analytical methods and incorporated sensitivity analysis on various demand drivers that impacted demand forecast assumptions. From this, we created 14 demand sensitivities and modeled five demand scenario alternatives, which incorporated differing customer growth, use per customer, weather and price elasticity assumptions. We developed three supply scenarios to consider various risks of resource uncertainties. This resulted in nine distinct portfolios analyzed within SENDOUT®.

We performed analysis on our peak day weather planning standard, performing sensitivity on HDDs and modeling an alternate weather planning standard using coldest day in 20 years. We supplemented this analysis with stochastic analysis running Monte Carlo simulations in SENDOUT®. We also used simulations from SENDOUT® to analyze price uncertainty and the effect on total portfolio cost.

We examined risk factors and uncertainties that could impact expectations and assumptions with respect to DSM programs and supply-side scenarios. From this, we developed three supply-side scenarios and included potential DSM savings for evaluation.

This investigation, identification and assessment of risks and uncertainties in our IRP process should reasonably mitigate surprise outcomes.

‖ CONCLUSION

The High Growth and Low Growth Case demand analysis provides a sufficient range for evaluating possible demand trajectories relative to our Expected Case. Based on this analysis we feel comfortable that we have sufficient time to plan for forecasted resource needs. Even under a very extreme growth scenario our first forecasted deficiency does not occur until 2018. The analysis shows a preference to meet the forecasted demand needs with the purchase of existing incremental pipeline capacity. We recognize that many things could happen between now and when our resource needs occur, therefore we will carefully monitor our demand trends and continually updated and evaluate all demand side and supply side alternatives.

CHAPTER 8 || DISTRIBUTION PLANNING

OVERVIEW

Avista's integrated resource planning encompasses evaluation of safe, economical and reliable full-path delivery of natural gas from basin to burner tip. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to our city gates become secondary issues if the distribution system behind the city gates is not adequately planned and becomes severely constrained. An important part of the planning process is to forecast future local demand growth, determine potential areas of distribution system constraints, analyze possible solutions and estimate costs for eliminating constraints.

Analyzing our resource needs to this point has focused on ensuring adequate capacity to our city gates, especially during a peak event (i.e. "Is there adequate volume for a peak day?"). Distribution planning focuses on "Is there adequate pressure during a peak hour?" Despite this altered perspective distribution planning shares many of the same goals, objectives, risks and solutions.

Avista's natural gas distribution system consists of approximately 5,400 miles of distribution main pipelines in Washington, 3,000 miles in Idaho and 3,500 miles in Oregon as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, there are no storage facilities or compression systems within our distribution system. System pressure is maintained by pressure regulating stations that utilize pipeline pressures from the interstate transportation pipelines before natural gas enters our distribution networks.

DISTRIBUTION SYSTEM PLANNING

Avista conducts two primary types of evaluations in its distribution system planning efforts to determine the need for resource additions including distribution system reinforcements and expansions. Reinforcements are upgrades in existing infrastructure or new system additions that increase system capacity, reliability and safety. Expansions are new system additions to accommodate new demand. Collectively we refer to these as distribution enhancements.

Ongoing evaluations of each distribution network in our four primary service territories are conducted to identify strategies for addressing local distribution requirements resulting from customer growth. Customer growth assessments are made based on many factors including our IRP demand forecasts[1], monitoring of gate station flows and other system metering, ongoing communication with construction staff and local area management regarding new service requests, field personnel discussion and inquiries from major developers.

Additionally, Avista regularly conducts integrity assessments of its distribution systems. This type of ongoing system evaluation can also indicate distribution upgrading requirements, but as a result of system maintenance needs rather than customer and load growth. In some cases, however, the timing for system integrity upgrades can coincide with growth related expansion requirements.

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[1] Distribution Planning forecasts customer growth rates by town code to generate local demand growth projections in its forecasting model consistent with the broader IRP customer forecasting methodology facilitating consistent integrated planning efforts. A town code is an unincorporated area within a county or a municipality within a county.

These planning efforts provide a long-term planning and strategy outlook and are integrated into our capital planning and budgeting process which incorporates planning for other types of distribution capital expenditures and infrastructure upgrades.

NETWORK DESIGN FUNDAMENTALS

Natural gas distribution networks rely on pressure differentials to flow gas from one place to another. When pressures are the same on both ends of a pipe the gas does not move. When gas is removed from a point on the network the pressure at that point drops lower than the pressure upstream in the network. Gas then moves from the higher pressure in the network to the point of removal attempting to equalize the pressure throughout the network. If gas removed is not sufficiently replaced by new gas entering the network the pressure differential will decrease, flow will stall and the network could run out of pressure. Therefore, it is important to design a distribution network so that the intake pressure (from gate stations and/or regulator stations) within the network is high enough to maintain an adequate pressure differential when gas leaves the network.

Not all gas flows equally throughout a network. Certain points within the network can constrain flow and thus restrict overall network capacity. Network constraints can occur over time as demand requirements on the network evolve. Anticipating these demand requirements, identifying potential constraints and forming cost-effective solutions with sufficient lead times without overbuilding infrastructure are the key challenges in network design.

COMPUTER MODELING

Developing and maintaining effective network design is significantly aided by computer modeling to perform network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means for analyzing the operation of a distribution system. Using a pipeline fluid flow formula a specified parameter of each pipe element can be simultaneously solved. A variety of pipeline equations exist, each tailored to a specific flow behavior. Through years of research these equations have been refined to the point where modeling solutions produced closely resemble actual system behavior.

Avista conducts network load studies using GL Noble Denton’s SynerGEE® 4.6.0 software. This computer-based modeling tool runs on a Windows operating system and allows users to analyze and interpret solutions graphically. Appendix 8.1 describes in detail our computer modeling methodology while Appendix 8.2 provides an example load study presentation including graphical interface and output examples.

DETERMINING PEAK DEMAND

For ease of maintenance and operation, safety to the public, reliable service and cost considerations, distribution networks operate at a relatively low pressure. Avista operates its distribution networks at a maximum operating pressure of 60 pounds per square inch (psig). Since distribution systems operate at pressure through relatively small diameter pipes there is essentially no line-pack capability for managing hourly demand fluctuations.

Core demand typically has a morning peaking period between 6 a.m. and 10 a.m. and an evening peaking period between 5 p.m. and 9 pm. The peak hour demand for these customers can be as much as 50% above the hourly average of the daily demand. Because of the importance of responding to hourly peaking in the distribution system, planning capacity requirements for our distribution systems are based on peak hour demand[2]. Included in Appendix 8.1 is the detailed methodology we use for determining peak demand.

DISTRIBUTION SYSTEM ENHANCEMENTS

Computer-aided demand studies facilitate modeling numerous "what if" demand forecasting scenarios, constraint identification and corresponding optimum combination of pipe modification and pressure modification solutions to maintain adequate pressures throughout the network over time.

Distribution system enhancements do not reduce demand nor do they create additional supply. However, they can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The three broad categories of distribution enhancement solutions are pipelines, regulators and compression.

PIPELINES

Pipeline solutions consist of looping, upsizing and uprating.

- **PIPELINE LOOPING** is the most common method of increasing capacity within an existing distribution system. It involves constructing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit pressure capacities downstream of the constraint creating inadequate pressure during periods of high demand. When the parallel line is connected to the system this second alternative path allows natural gas flow to bypass the original constraint point and bolster downstream pressure capacities. The feasibility of looping a pipeline is primarily dependent upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt and steep or rocky terrain can greatly increase the cost to amounts that are unjustifiable so that other alternative solutions offer a more cost effective solution.
- **PIPELINE UPSIZING** is simply replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area of the pipe results in less friction and therefore a lower pressure drop. This option is usually pursued when there is damaged pipe or pipe integrity issues exist. If the existing pipe is otherwise in satisfactory condition looping is usually pursued, allowing the existing pipe to remain in use.
- **PIPELINE UPRATING** involves increasing the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional system facilities. However, safety considerations and pipe regulations may prohibit feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating unanticipated costly repairs.

REGULATORS

Regulators or regulator stations are used to reduce pipeline pressure at various stages within the distribution. The primary purpose of regulation is to provide a specified and constant outlet pressure before gas continues its downstream travel to a city's distribution system, customer's property or gas appliance. Regulators also ensure that flow requirements are met at a desired pressure regardless of fluctuations upstream of the regulator. Regulators can be found at city gate stations, district regulators stations, farm taps and customer services.

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[2] This method differs from the approach that we use for broader IRP peak demand planning which focuses on peak day requirements to the city gate.

COMPRESSION

Compressor stations present a capacity enhancing option for pipelines with significant gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of gas a single, large volume compressor can be installed in the optimal position along the pipeline to boost downstream pressure. However, this type of compressor configuration will not function effectively if the flow in the pipeline has high variability.

A second option is the installation of multiple, smaller compressors located close together or strategically placed in different locations along a pipeline. Multiple compressors accommodate a large flow range and the use of smaller and very reliable compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace so that purchasing and installing these less expensive compressors can be done over time allowing a pipeline to serve growing customer demand for many years into the future.

Compressors can be a cost effective, feasible option to resolving constraint points; however, regulatory and environmental approvals to install a station along with engineering and construction time can be a significant deterrent. Also, adding compressor stations within a distribution system typically involves considerable capital expenditure. Based on our detailed knowledge of our distribution system, we do not currently envision or have any foreseeable plans to add compressors to our distribution network.

CONSERVATION RESOURCES

Included in our evaluation of distribution system constraints is consideration of targeted conservation resources that could reduce or delay distribution system enhancements. We are mindful; however, that the consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this we attempt to influence these decisions but we do not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraint areas. Over longer-term planning we do recognize that targeted conservation programs provide a cumulative benefit that offsets potential constraint areas and may be an effective strategy.

PLANNING RESULTS

Table 8.1 summarizes the cost of major distribution system enhancement projects which address future growth-related system constraints as well as system integrity issues and the anticipated timing of expenditures. These proposed projects are preliminary estimates of timing and costs of reinforcement solutions. The scope and needs of these projects can evolve over time with new information requiring ongoing reassessment. Actual solutions may be different due to differences in actual growth patterns and/or construction conditions from those assumed in the initial assessment.

The following discussion provides further information on our key near-term projects:

3203 - EAST MEDFORD REINFORCEMENT – Observed local growth and our IRP indicate increased gas deliveries will likely be needed from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford. To facilitate distribution receipt of the increased gas volumes, a new HP gas line encircling Medford to the east and tying into an existing high-pressure feeder in White City will improve delivery capacity and provide a much needed reinforcement in the East Medford area which is forecasting higher growth.

3237 – U.S. 2 NORTH SPOKANE REINFORCEMENT – This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area with residential, commercial and industrial demand experiences low pressure at unpredictable times given varied demand profiles of the diverse customer base. Completion of this reinforcement will improve pressures in the U.S. 2 north Kaiser area. Approximately 8,000 feet of HP steel will be installed in a newly established easement along U.S. Highway 2.

3296 – CHASE RD GATE STATION, POST FALLS, ID – This gate station will allow Avista to split the large load at the Rathdrum Gate Station. Approximately 18,000 feet of high-pressure line will be built to connect Chase Rd Gate Station to the existing high pressure. This gate station will also give Avista the opportunity to feed the growing the Post Falls and Coeur d'Alene areas from the north.

Table 8.1 Distribution Planning Capital Projects

				Estimated Budget and Timing					
	Ref #	Title	State	2012	2013	2014	2015	Beyond 2015	Total
	3000	Gas Reinfrc-Minor Blanket	ALL	800,002	1,050,000	1,050,000	1,050,000	1,050,000	5,000,002
	3001	Rep Deteriorating Gas Systems (Non-Aldyl-A)	ALL	800,006	1,000,000	1,000,000	1,000,000	1,000,000	4,800,006
	3002	Reg Reliable - Blanket	ALL	400,006	500,000	500,000	500,000	500,000	2,400,006
	3003	Gas Replc-St&Hwy	ALL	2,200,007	2,250,000	2,250,000	2,250,000	2,250,000	11,200,007
	3004	Cath Prot-Minor Blanket	ALL	500,003	500,000	500,000	500,000	500,000	2,500,003
	3005	Gas Dist Non-Rev Blanket	ALL	3,823,013	3,937,703	4,055,834	4,177,510	4,302,835	20,296,895
	3006	Overbuild Pipe Replacement	ALL	500,002	500,000	500,000	500,000	500,000	2,500,002
	3007	Isolated Steel Pipe Replacement, Various Locations	ALL	1,095,004	990,000	1,000,000	1,000,000	1,000,000	5,085,004
	3117	Gas Telemetry	ALL	370,801	100,000	100,000			570,801
	3296	Upgrade - YZ Odorizers, Various Locations (6ea.)	ALL	150,000					150,000
*	3246	Chase Rd Gate Station, Post Falls, ID	ID		2,100,000	2,164,000			4,264,000
	3275	Upgrade - Coeur d'Alene East Tap Upgrade, Coeur d'Alene, ID	ID						
	3279	Reinforcement - HP Main Extension south from CDA East Gate, CDA ID	ID						
	3292	Reinforcement - Sprit lake HP Main, Athol ID	ID						
	3297	Hwy 95 Relocation, CDA ID	ID	3,000,000					3,000,000
	3298	Old Hwy 95 Relocation, CDA ID	ID	1,250,000					1,250,000
	TBD	Post Falls HP Extension	ID			2,000,000	3,000,000	3,000,000	8,000,000
*	3203	East Medford	OR	550,000		4,100,000			4,650,000
	3242	Reinforce Talent OR Gate Station&Piping	OR						
	3257	Oakland Bridge Bore and Relocation, Oakland OR	OR	181,000					181,000
	3274	Reinforcement, Loop the existing 6" HP from Tolo to White City	OR						
	3112	Re-Rte Kettle Falls Feed & Gate Station	WA						
*	3237	US2 N Spo Gas HP Reinforce(Kaiser Prop)	WA		1,300,000				1,300,000
	3245	Cheney 8" HP Feeder Project	WA						
	3264	Appleway to Henry Reinforcement, Spokane Valley WA	WA						
*	Details of project described in IRP			**14,819,842**	**13,177,703**	**18,169,834**	**12,927,510**	**13,052,835**	**72,147,724**

CONCLUSION

Avista's goal is to maintain its distribution systems reliably and cost effectively to deliver natural gas to every customer. This goal can be achieved with computer modeling, which increases the reliability of the distribution system by identifying specific areas within the system that may require changes.

The ability to meet our goal of reliable cost effective gas delivery is also enhanced through the recent integration of customer growth forecasting at the town code level and localized distribution planning enabling coordinated targeting of distribution projects that are responsive to detailed customer growth patterns.

CHAPTER 9 ꞁꞁ ACTION PLAN

2010-2011 ACTION PLAN REVIEW

The 2010-2011 Action Plan focused on the following areas:

- Integrated Resource Portfolio
- Demand Forecasting
- Demand-Side Management
- Supply-Side Resources

A discussion of the specific action items and the plan results follows.

ACTION ITEM

Monitor actual demand closely for indications of faster growth exceeding our forecasted growth to respond aggressively to address potential accelerated resource deficiencies arising from our exposure to "flat demand" risk. This includes researching and refining the evaluation of resource alternatives, including implementation risk factors and timelines, updated cost estimates and feasibility assessments targeting options for the service territories with nearer-term unserved demand exposure.

RESULTS

We continue to monitor demand and compare actual results to IRP forecasted demand. Trends so far indicate slower than anticipated customer growth and continued declines in weather normalized use-per-customer, which has delayed the need for resource acquisitions.

ACTION ITEM

Analyze actual use-per-customer data and DSM program results for indications of price elasticity response trends that may have been influenced by evolving economic conditions. Investigate contemporary analytical sources for information on natural gas price elasticity. Explore persuading the AGA to update their analytical work and/or consider hiring a third-party price elasticity study including assessing interest of other utilities in pursuing a regional project.

RESULTS

As part of our reconciliation of forecasted demand to actual demand we analyze weather normalized use – per customer. While rates have remained relatively stable over the last few years, customers have decreased their overall usage. Trying economic times, successful adoption of demand-side management initiatives and appliance and building code efficiencies have contributed to the lower use per customer. Long run price elasticity does not change much over time; however we did approach the AGA to update their analytic work. Like man, the AGA was managing a tight budget and did not have the dollars to undertake an updated study.

ACTION ITEM

Continue our pursuit of cost effective demand-side solutions to reduce demand. In Washington and Idaho conservation measures are targeted to reduce demand by approximately 2,193,000 therms in the first year. In Oregon conservation measures are targeted to reduce demand by approximately 303,000 therms in the first year. These goals represent increases of 54 percent in Washington and Idaho and 1 percent in Oregon from our prior 2007 IRP.

RESULTS

Avista actively pursues cost-effective demand-side management solutions to reduce demand. In 2010 and 2011 Washington and Idaho conservation measures reduced demand by approximately 1,850,000 therms and 1,730,000 therms. In Oregon demand was reduced by 312,000 therms and 313,000 therms.

ACTION ITEM

Research and engage a conservation consultant to perform an updated assessment of conservation technical and achievable potential in our service territories prior to the next IRP.

RESULTS

Global Energy Partners performed a conservation potential assessment for Avista's natural gas and electric demand-side management programs. Results from this analysis were used in the 2012 Natural Gas IRP and a copy of the assessment is included in Appendix 4.1.

ACTION ITEM

Continue to monitor the discussion around diminishing Canadian gas exports looking for signals that indicate increased risk of disrupted supply over the 20-year planning horizon. Since much of our supply comes from Canadian natural gas exports the notion that this supply could diminish significantly remains a concern.

RESULTS

During the 2009 IRP supplies available for import into the United States were showing signs of decline. Since then the supply picture for North America has changed dramatically. The widespread availability of shale gas throughout the U.S. and Canada has greatly reduced the concern that supplies will diminish.

ACTION ITEM

Explore and evaluate alternative and additional forecasting methodologies for potential inclusion in our next IRP. Methodologies to be evaluated include statistical, non-statistical, quantitative, qualitative and terrain overview approaches.

RESULTS

We continue to believe our forecasting methodology is sound, cost effective and adequate; however we have explored several alternative forecasting methodologies for possible consideration in our IRP planning. Our methodology allows the ability to vary the results of our statistical inputs by considering both qualitative and quantitative factors. These factors can be derived from data or surveys of market information, fundamental forecasters, and industry experts. We are always open to new methods of forecasting demand and are assessing which, if any, alternative methodologies to include in future IRPs.

❚❚ ACTION ITEM

Meet regularly with Commission Staff members to provide information on market activities, material changes to risk management programs, and significant changes in assumptions and/or status of company activity related to the IRP or procurement practices.

❚❚ RESULTS

We have met and will continue to meet no less than biannually with Commission Staff members to provide updates on market fundamentals, procurement planning initiatives, changes to risk management programs, and significant changes of assumptions related to the IRP.

2013-2014 ACTION PLAN

Since our 2009 IRP customer growth has slowed and it is not anticipated to rebound in the near term. We have also seen use per customer reductions as customers have become more household budget conscience, changed usage behavior, and over the last few years have invested in conservation measures. These factors have reduced overall and peak day demand when compared to our 2009 IRP.

Based on the analysis conducted for the 2012 IRP, under our Expected Case, we do not anticipate the need to acquire additional supply side resources in the next two to three years. Furthermore, even our most aggressive High Growth/Low Price scenario did not indicate supply side needs within the next few years. The Average, Alternate Planning Standard, and Low Growth/High Price scenarios do not indicate any resource deficiencies within the planning horizon. We will actively monitor our demand looking for indications of deviations away from our Expected Case.

The demand forecast was not the only thing that changed dramatically. The price of natural gas has dropped significantly since our last IRP. Robust North American supplies lead by shale gas developments coupled with lackluster demand due to the economy has pushed prices down to levels not seen in the last decade. These low prices, while good for our customers, challenge the cost-effectiveness of DSM at the program level. Since the drafting of this document, Avista has filed in Washington and Idaho to suspend natural gas DSM programs and is currently evaluating programs in Oregon.

Over the next two to three years, Avista will be watching natural gas prices as a sign post for the cost-effectiveness of DSM programs. Should prices move significantly Avista will again be proactive in seeking to reinstate a full complement of our natural gas DSM programs.

Continued enhancement of our gate station analysis will also be completed to assess if there are individual gate station deficiencies that are masked by our aggregated IRP analysis. Should any deficiencies be identified we will discuss findings and potential solutions with Commission Staff. We will continue to coordinate analytic efforts between Gas Supply, Gas Engineering, and the intrastate pipelines to perform gate station analysis and if deficiencies are identified seek least cost solutions.

❚❚ ONGOING ACTION ITEMS

- Monitor actual demand for indications of growth exceeding our forecast to respond aggressively to address potential accelerated resource deficiencies arising from exposure to “flat demand” risk. This will include providing commission staff with IRP demand forecast to actual variance analysis on customer growth and use per customer. This information will be provided in Avista's updates to each commission staff at least biannually.

- Pursue the possibility of a regional elasticity study through the Northwest Gas Association or possibly the American Gas Association.
- Assess potential demand impact from NGV/CNG vehicles and other new uses of natural gas to Avista.
- Continue to monitor supply resource trends including the availability and price of natural gas to the regions, exporting LNG, Canadian natural gas imports and interprovincial consumption, regional plans for gas-fired generation and its affect on pipeline availability, as well as regional pipeline and storage infrastructure plans.
- Monitor new resource lead time requirements relative to when resources are needed to preserve resource option flexibility.
- Regularly meet with Commission Staff members to provide information on market activities and significant changes in assumptions and/or status of Avista activities related to the IRP or natural gas procurement practices.

CHAPTER 10 GLOSSARY OF TERMS AND ACRONYMS

ACHIEVABLE POTENTIAL
Represents a realistic assessment of expected energy savings recognizing and accounting for economic and other constraints that preclude full installation of every identified conservation measure.

AGA
American Gas Association

ANNUAL MEASURES
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Annual measures are also often called base load measures.

AVISTA
The regulated Operating Division of Avista Corp.; separated into north (Washington and Idaho) and south (Oregon) regions; Avista Utilities generates, transmits and distributes electricity in addition to the transmission and distribution of natural gas.

BACKHAUL
A transaction where gas is transported the opposite direction of normal flow on a unidirectional pipeline.

BASE LOAD
As applied to natural gas, a given demand for natural gas that remains fairly constant over a period of time, usually not temperature sensitive.

BASE LOAD MEASURES
Conservation measures that achieve generally uniform year round energy savings independent of weather temperature changes. Base load measures are also often called annual measures.

BASIS DIFFERENTIAL
The difference in price between any two natural gas pricing points or time periods. One of the more common references to basis differential is the pricing difference between Henry Hub and any other pricing point in the continent.

BRITISH THERMAL UNIT (BTU)
The amount of heat required to raise the temperature of one pound of pure water one degree Fahrenheit under stated conditions of pressure and temperature; a therm (see below) of natural gas has an energy value of 100,000 BTUs and is approximately equivalent to 100 cubic feet of natural gas.

CD
Contract Demand

C&I
Commercial and Industrial

CITY GATE (ALSO KNOWN AS GATE STATION OR PIPELINE DELIVERY POINT)
The point at which natural gas deliveries transfer from the interstate pipelines to Avista's distribution system.

CNG
Compressed Natural Gas

COMPRESSION
Increasing the pressure of natural gas in a pipeline by means of a mechanically driven compressor station to increase flow capacity.

CONSERVATION MEASURES
Installations of appliances, products or facility upgrades that result in energy savings.

CONTRACT DEMAND (CD)
The maximum daily, monthly, seasonal or annual quantities of natural gas, which the supplier agrees to furnish, or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

CORE LOAD
Firm delivery requirements of Avista, which are comprised of residential, commercial and firm industrial customers.

COST EFFECTIVENESS
The determination of whether the present value of the therm savings for any given conservation measure is greater than the cost to achieve the savings.

CPA
Conservation Potential Assessment

CPI
Consumer Price Index, as calculated and published by the U.S. Department of Labor, Bureau of Labor Statistics

CUBIC FOOT (CF)
A measure of natural gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor; one cubic foot of natural gas has the energy value of approximately 1,000 BTUs and 100 cubic feet of natural gas equates to one therm (see below).

CURTAILMENT
A restriction or interruption of natural gas supplies or deliveries; may be caused by production shortages, pipeline capacity or operational constraints or a combination of operational factors.

DEKATHERM
Unit of measurement for natural gas; a dekatherm is 10 therms, which is one thousand cubic feet (volume) or one million BTUs (energy).

DEMAND-SIDE MANAGEMENT (DSM)
The activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods.

DEMAND-SIDE RESOURCES
Energy resources obtained through assisting customers to reduce their "demand" or use of natural gas. Also represents the aggregate energy savings attained from installation of conservation measures.

DSM
Demand-Side Management

DTH
Unit of measurement for natural gas; a dekatherm is 10 therms, which is one thousand cubic feet (volume) or one million BTUs (energy).

EIA
Energy Information Administration

EXTERNAL ENERGY EFFICIENCY BOARD
Also known as the "Triple-E" board, this non-binding external oversight group was established in 1999 to provide Avista with input on DSM issues.

EXTERNALITIES
Cost and benefits that are not reflected in the price paid for goods or services.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)
The government agency charged with the regulation and oversight of interstate natural gas pipelines, wholesale electric rates and hydroelectric licensing; the FERC regulates the interstate pipelines with which Avista does business and determines rates charged in interstate transactions.

FERC
Federal Energy Regulatory Commission

FIRM SERVICE
Service offered to customers under schedules or contracts that anticipate no interruptions; the highest quality of service offered to customers.

FORCE MAJEURE
An unexpected event or occurrence not within the control of the parties to a contract, which alters the application of the terms of a contract; sometimes referred to as "an act of God;" examples include severe weather, war, strikes, pipeline failure and other similar events.

FORWARD PRICE
The future price for a quantity of natural gas to be delivered at a specified time.

GAS TRANSMISSION NORTHWEST (GTN)
A subsidiary of TransCanada Pipeline which owns and operates a natural gas pipeline that runs from the Canada/USA border to the Oregon/California border. One of the six natural gas pipelines Avista transacts with directly.

GEOGRAPHIC INFORMATION SYSTEM (GIS)
A system of computer software, hardware and spatially referenced data that allows information to be modeled and analyzed geographically.

GHG
Greenhouse Gas

GLOBAL INSIGHT, INC.
A national economic forecasting company.

GTN
Gas Transmission Northwest

HEATING DEGREE DAY (HDD)
A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below 65 degrees Fahrenheit; a daily average temperature represents the sum of the high and low readings divided by two.

HENRY HUB
The physical location found in Louisiana that is widely recognized as the most important pricing point in the United States. It is also the trading hub for the New York Mercantile Exchange (NYMEX).

HP
High Pressure

INJECTION
The process of putting natural gas into a storage facility; also called liquefaction when the storage facility is a liquefied natural gas plant.

INTEGRITY MANAGEMENT PLAN
A federally regulated program that requires companies to evaluate the integrity of their natural gas pipelines based on population density. The program requires companies to identify high consequence areas, assess the risk of a pipeline failure in the identified areas and provide appropriate mitigation measures when necessary.

INTERRUPTIBLE SERVICE
A service of lower priority than firm service offered to customers under schedules or contracts that anticipate and permit interruptions on short notice; the interruption happens when the demand of all firm customers exceeds the capability of the system to continue deliveries to all of those customers.

IPUC
Idaho Public Utilities Commission

IRP
Integrated Resource Plan; the document that explains Avista’s plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price.

JACKSON PRAIRIE
An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and NWP; the project is a naturally occurring aquifer near Chehalis, Washington, which is located some 1,800 feet beneath the surface and capped with a very thick layer of dense shale.

LIQUEFACTION
Any process in which natural gas is converted from the gaseous to the liquid state; for natural gas, this process is accomplished through lowering the temperature of the natural gas (see LNG).

LIQUEFIED NATURAL GAS (LNG)
Natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

LINEAR PROGRAMMING
A mathematical method of solving problems by means of linear functions where the multiple variables involved are subject to constraints; this method is utilized in the SENDOUT® Gas Model.

LOAD DURATION CURVE
An array of daily send outs observed that is sorted from highest send out day to lowest to demonstrate both the peak requirements and the number of days it persists.

LOAD FACTOR
The average load of a customer, a group of customers, or an entire system, divided by the maximum load; can be calculated over any time period.

LOCAL DISTRIBUTION COMPANY (LDC)
A utility that purchases natural gas for resale to end-use customers and/or delivers customer's natural gas or electricity to end users' facilities.

LOOPING
The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

MCF
A unit of volume equal to a thousand cubic feet.

MDDO
Maximum Daily Delivery Obligation

MDQ
Maximum Daily Quantity

MMBTU
A unit of heat equal to one million British thermal units (BTUs) or 10 therms. Can be used interchangeably with Dth.

NATIONAL ENERGY BOARD
The Canadian equivalent to the Federal Energy Regulatory Commission (FERC).

NATIONAL OCEANIC ATMOSPHERIC ADMINISTRATION (NOAA)
Publishes the latest weather data; the 30-year weather study included in this IRP is based on this information.

NATURAL GAS
A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum; the principal constituent is methane, and it is lighter than air.

NEW YORK MERCANTILE EXCHANGE (NYMEX)
An organization that facilitates the trading of several commodities including natural gas.

NGV
Natural Gas Vehicles

NOAA
National Oceanic and Atmospheric Administration

NOMINAL
Discounting method that includes inflation.

NOMINATION
The scheduling of daily natural gas requirements.

NON-COINCIDENTAL PEAK DEMAND
The demand forecast for a 24-hour period for multiple regions that includes at least one peak day and one non-peak day.

NON-FIRM OPEN MARKET SUPPLIES
Natural gas purchased via short-term purchase arrangements; may be used to supplement firm contracts during times of high demand or to displace other volumes when it is cost-effective to do so; also referred to as spot market supplies.

NORTHWEST PIPELINE CORPORATION (NWP)
A principal interstate pipeline serving the Pacific Northwest and one of six natural gas pipelines Avista transacts with directly. NWP is a subsidiary of The Williams Companies and is headquartered in Salt Lake City, Utah.

NOVA GAS TRANSMISSION (NOVA)
See TransCanada Alberta System

NORTHWEST POWER AND CONSERVATION COUNCIL (NPCC)
A regional energy planning and analysis organization headquartered in Portland, Ore.

NPCC
Northwest Power and Conservation Council

NWP
Williams-Northwest Pipeline

NYMEX
New York Mercantile Exchange

OPUC
Oregon Public Utility Commission

PEAK DAY
The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.

PEAK DAY CURTAILMENT
Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for natural gas exceed the maximum daily delivery capability of a pipeline system.

PEAKING CAPACITY
The capability of facilities or equipment normally used to supply incremental natural gas under extreme demand conditions (i.e. peaks); generally available for a limited number of days at this maximum rate.

PEAKING FACTOR
A ratio of the peak hourly flow and the total daily flow at the city-gate stations used to convert daily loads to hourly loads.

PRESCRIPTIVE MEASURES
Avista's DSM tariffs require the application of a formula to determine customer incentives for natural gas-efficiency projects. For commonly encountered efficiency applications that are relatively uniform in their characteristics the utility has the option to define a standardized incentive based upon the typical application of the efficiency measure. This standardized incentive takes the place of a customized calculation for each individual customer. This streamlining reduces both the utility and customer administrative costs of program participation and enhances the marketability of the program.

PSIG
Pounds per square inch gauge – a measure of the pressure at which natural gas is delivered.

PVRR
Present Value Revenue Requirement

RATE BASE
The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return; generally this represents the amount of property used and useful in service to the public.

REAL
Discounting method that excludes inflation.

RESOURCE STACK
Sources of natural gas infrastructure or supply available to serve Avista's customers.

SEASONAL CAPACITY
Natural gas transportation capacity designed to service in the winter months.

SENDOUT
The amount of natural gas consumed on any given day.

SENDOUT®
Natural gas planning system from Ventyx; a linear programming model used to solve gas supply and transportation optimization questions.

SERVICE AREA
Territory in which a utility system is required or has the right to provide natural gas service to ultimate customers.

SPOT MARKET GAS
Natural gas purchased under short-term agreements as available on the open market; prices are set by market pressure of supply and demand.

STORAGE
The utilization of facilities for storing natural gas which has been transferred from its original location for the purposes of serving peak loads, load balancing and the optimization of basis differentials; the facilities are usually natural geological reservoirs such as depleted oil or natural gas fields or water-bearing sands sealed on the top by an impermeable cap rock; the facilities may be man-made or natural caverns. LNG storage facilities generally utilize above ground insulated tanks.

TAC
Technical Advisory Committee

TARIFF
A published volume of regulated rate schedules plus general terms and conditions under which a product or service will be supplied.

TF-I
NWP's rate schedule under which Avista moves natural gas supplies on a firm basis.

TF-2
NWP's rate schedule under which Avista moves natural gas supplies out of storage projects on a firm basis.

TECHNICAL ADVISORY COMMITTEE (TAC)
Industry, customer and regulatory representatives that advise Avista during the IRP planning process.

TECHNICAL POTENTIAL
An estimate of all energy savings that could theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness.

THERM
A unit of heating value used with natural gas that is equivalent to 100,000 British thermal units (BTU); also approximately equivalent to 100 cubic feet of natural gas.

TOWN CODE
A town code is an unincorporated area within a county and a municipality within a county served by Avista natural gas retail services.

TRANSCANADA ALBERTA SYSTEM
Previously known as NOVA Gas Transmission; a natural gas gathering and transmission corporation in Alberta that delivers natural gas into the TransCanada BC System pipeline at the Alberta/British Columbia border; one of six natural gas pipelines Avista transacts with directly.

TRANSCANADA BC SYSTEM
Previously known as Alberta Natural Gas; a natural gas transmission corporation of British Columbia that delivers natural gas between the TransCanada-Alberta System and GTN pipelines that runs from the Alberta/British Columbia border to the United States border; one of six natural gas pipelines Avista transacts with directly.

TRANSPORTATION GAS
Natural gas purchased either directly from the producer or through a broker and is used for either system supply or for specific end-use customers, depending on the transportation arrangements; NWP and GTN transportation may be firm or interruptible.

TRC
Total Resource Cost

TRIPLE E
External Energy Efficiency Board

TUSCARORA GAS TRANSMISSION COMPANY
Tuscarora is a subsidiary of Sierra Pacific Resources and TransCanada; this natural gas pipeline runs from the Oregon/California border to Reno, Nevada; one of the six natural gas pipelines Avista transacts with directly;

VAPORIZATION
Any process in which natural gas is converted from the liquid to the gaseous state.

WCSB
Western Canadian Sedimentary Basin

WEIGHTED AVERAGE COST OF GAS (WACOG)
The price paid for a volume of natural gas and associated transportation based on the prices of individual volumes of natural gas that make up the total quantity supplied over an established time period.

WEATHER NORMALIZATION
The estimation of the average annual temperature in a typical or "normal" year based on examination of historical weather data; the normal year temperature is used to forecast utility sales revenue under a procedure called sales normalization.

WEATHER SENSITIVE MEASURES
Conservation measures whose energy savings are influenced by weather temperature changes. Weather sensitive measures are also often referred to as winter measures.

WINTER MEASURES
Conservation measures whose energy savings are influenced by weather temperature changes. Winter measures are also often referred to as weather sensitive measures.

WITHDRAWAL
The process of removing natural gas from a storage facility, making it available for delivery into the connected pipelines; vaporization is necessary to make withdrawals from an LNG plant.

WUTC
Washington Utilities and Transportation Commission

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF LARRY D. LA BOLLE
REPRESENTING AVISTA CORPORATION

Aldyl A Natural Gas Pipe Replacement and Project Compass

I. INTRODUCTION

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

A. My name is Larry La Bolle and I am employed as the Director of Federal and Regional Affairs for Avista Utilities, at 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. Prior to joining the Company in 1990, I earned a Bachelor of Science Degree in Fisheries Science from the University of Idaho. I have also earned a Master's Degree in Fisheries Science from Oregon State University. Prior to joining the Company, I was employed by the Idaho Department of Fish and Game as a fishery research biologist, and later as regional fishery manager. I spent approximately nine years in the Environmental Affairs Department and managed the Company's federal relicensing of its Clark Fork Hydroelectric projects. Since 1999, I have managed economic and community development, led a pilot joint-venture subsidiary operation with Chelan County PUD, and managed gas and electric operations for Idaho and Southeast Washington. I have worked in my present capacity since 2005. I serve on several boards, including Northwest River Partners, Pacific Northwest Utilities Conference Committee, Governor Otter's Idaho Strategic Energy Alliance, and the College of Natural Resources Alumni Board of Trustees for the University of Idaho.

Q. What is the scope of your testimony?

A. I will discuss the status of the Company's ongoing program to replace early-vintage Aldyl A piping in our natural gas distribution system, as well as the ongoing effort to replace the Company's legacy Customer Information System (Project Compass).

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. 501 and 502. Exhibit No. 501 is a Company report documenting its development of a protocol for managing select vintages of Aldyl A natural gas pipe, providing the rationale for the Company's Aldyl A Pipe Replacement Project. Exhibit No. 502 includes a report and attachments that provide an overview of Project Compass, the Company's ongoing project to replace its legacy Customer Information System.

II. ALDYL A PIPE REPLACEMENT PROGRAM

Q. Please describe Avista's plan for managing its Aldyl A polyethylene natural gas pipe?

A. The Company has undertaken a twenty-year program to systematically replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system in the States of Oregon, Idaho and Washington. None of the subject pipe is "high pressure main pipe," but rather consists of distribution mains at maximum operating pressures of 60 psi and pipe diameters ranging from 1¼ to 4 inches. As part of this program, Avista is also replacing the connections where Aldyl A service piping, in ½ and ¾ inch diameters, is tapped to steel main pipe (transition tees).

Q. How many miles of main pipe and number of transition tees did the Company initially identify for replacement?

A. In 2011, Avista identified approximately 721 miles of Priority Aldyl A main pipe and approximately 16,000 transition tees for replacement across its three

State jurisdictions. Replacement of main pipe commenced in 2011, and by the close of construction in 2012, approximately 22 miles of main had been replaced. Only nominal numbers of transition tees were replaced in 2011-12. The miles of main pipe and number of transition tees remaining for replacement, at the close of construction in 2012, as well as the cumulative capital expenditures, by jurisdiction, are summarized in the table below.

State	Remaining **Main Pipe** (miles)	Remaining **Tees** (number)	Replacement **Cost** (to date)
Oregon	246.2	5,344	$1,507,495.93
Idaho	130.5	3,124	$62,177.47
Washington	332.4	7,169	$5,841,701.04
Totals	709.1	15,637	$7,411,375.44

Q. Has Avista sought recovery of the expenditures made under this program in Idaho and Washington?

A. Yes. The Company received approvals in both jurisdictions for the costs included in the recent general rate cases.

Q. Why did the Company initiate this replacement program?

A. In recent years, Avista experienced incidents on its natural gas system that prompted the formal assessment of the long-term reliability of certain vintages of its Aldyl A piping. These vintages have been shown to have an increased propensity for brittleness and cracking over time. Results of the investigations, which were aided by new tools developed for Avista's Distribution Integrity Management Plan, corroborated reports for similar Aldyl A piping around the Country, and supported the development of a protocol for managing this natural gas pipe, which Avista refers to as "Priority Aldyl A." The report documenting the Company's evaluation of this piping, and the development of its management protocol, titled: "Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System" (or Protocol), is attached to this testimony as Exhibit No. 501. The Protocol explains in detail the nature of the failures in this pipe, how the Company assessed its long-term integrity, and the rationale for its decision to replace this piping.

Q. Why did the Company elect to carry out this pipeline replacement program over 20 years?

A. Avista modeled various time horizons for removing and replacing this pipe, between 10 and 30 years, and determined a replacement horizon in the range of twenty years represented an optimum timeframe. Shortening the timeline was found to increase costs for customers but with little improvement in the numbers of expected Aldyl A failures (or leaks). Lengthening the timeline past twenty years, however, resulted in a substantial increase in the number of expected material failures. A replacement timeline of 25 years, for example, resulted in more than a doubling of the number of leaks expected when compared with the 20-year horizon.

Q. Could the 20-year replacement time change as the work proceeds?

A. Yes. The current approach, based on the 20-year replacement horizon, was an optimization based on the information available at the time the Protocol was developed. At that time, the Company noted that as the initial work proceeded, any number of factors could influence the modeling results toward either a shorter or longer optimum time horizon.

Q. Has Avista continued to collect new information needed to re-evaluate its forecast of the optimum time horizon?

A. Yes. As mentioned above, the Company has collected and analyzed new leak survey and other data each year, as well as continuing to better understand the risks on its distribution system through the ongoing implementation of its Distribution Integrity Management Plan. Avista will continue to evaluate this information in determining whether to accelerate the replacement program.

Q. Has the Company made any adjustments to the program since it began?

A. Yes. Avista has been conducting leak surveys of its Priority Aldyl A main pipe, annually, rather than the conventional five-year cycle. The Company elected in the fall of 2012 to also initiate annual leak surveys of its Aldyl A transition tees. Though annual survey of transition tees is complicated and costly compared with the conventional five-year cycle, Avista believes it will provide a prudent added margin of safety during the period of time these services are being remediated.

In addition, the Company has also accelerated the replacement of Aldyl A transition tees. Avista initially anticipated that the replacement of main pipe and transition tees would be conducted together. But, it became evident that mixing these activities would create inefficiencies and add to costs. Accordingly, the Company focused its initial effort on main pipe replacement using crews that were specialized in this activity. Avista now has specialized contract crews dedicated to replacement of the transition tees. The acceleration of this work reflects the Company’s assessment of transition tees as potentially having a higher forecast failure rate than main pipe.

Q. What are the expected capital costs associated with the overall Aldyl A replacement program?

A. Avista's initial estimate of the annual capital cost was approximately $10 million, excluding inflation, to be spent across all its natural gas jurisdictions, from 2013 – 2032. In addition to annual variability in spending, based on factors such as the priority-grouping of projects slated for replacement each year, Avista also understood that its initial estimates would be refined by actual replacement cost experience as the program moved forward.

Q. What challenges has the Company experienced during the initial years of this program?

A. Avista has completed the majority of its Aldyl A replacement work using contract crews and equipment, since this effort is additive to the normal workload and staffing levels associated with the Company's ongoing natural gas operations. Contrary to Avista's initial assessment in 2011, however, securing qualified contract crews for such a large, diverse, and long-term project has been a challenge. This is due in part to the national demand for skilled craft labor and equipment driven by similar-type pipe replacement programs, and the significant demands created by shale oil and natural gas exploration and production. A related challenge is the need to keep contractors fully engaged year-round. Contract crews that would have once been seasonally idled due to winter conditions, must now be employed full time in order to prevent them from naturally moving to other year-round work opportunities.

Q. How has the Company been able to address this challenge?

A. In order to provide greater security related to contract resources, the Company initiated a request for proposals, which ultimately resulted in Avista's selection of Northern Pipeline Construction Company (Northern Pipeline)[1] in March 2013. Northern Pipeline will be engaged for a 5-year term to perform the Company's Aldyl A main pipe replacement and transition tee replacements. One of the attributes Avista considered in selecting NPL is their proven expertise and capability to perform "pipe splitting"[2] and "keyhole"[3] construction techniques. In certain applications, these techniques can provide very cost-effective alternatives to conventional practices requiring street-cutting and excavation.

Q. What other issues has Avista faced in conducting its Aldyl A replacement program?

A. Among a range of other issues, the predominant challenge is the rise in construction costs caused by the increasing restrictiveness of pavement cutting and remediation policies of local jurisdictions. In addition to added direct cost, these policies also impact project scheduling and logistics. Avista has experienced a broad trend among jurisdictions to establish more restrictive moratoria on pavement cutting in newer arterials and streets, and more costly requirements for the backfilling, patching and repaving of streets cut for pipe replacement. The driver appears to be local jurisdictions seeking ways to maintain and improve streets under tighter operating budgets associated with the broad economic recession. This added cost is particularly

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[1] NPL has a national reputation for safe, high quality, cost-effective solutions and customer satisfaction, installing and replacing over ten million feet of pipe, wire, and information systems annually. NPL Corporate Headquarters is located in Phoenix Arizona.

[2] Pipe Splitting is a technique that enables a section of plastic pipe to be replaced with only limited street cutting and excavation. Under this technique, two endpoints of a given length of pipe to be replaced are excavated. This provides access for a specialized head to be pulled through the pipe from one end to the other. This action simultaneously splits the existing pipe and pulls the new pipe into position in its place, without disturbing the surface along the length of the pipe section.

[3] Keyhole technology allows the work on underground facilities through an 18 inch-diameter hole in a street's pavement. When the job is complete, the street is restored by putting the pavement core back into place with no waste from asphalt mixing. Cost reductions also come from eliminating the need for a backhoe and asphalt hot-patch crew or replacing concrete.

significant, because in the Company's recent experience, it can result in street repair costs accounting for up to 70% of the total replacement program cost (i.e. 30% for pipe replacement and 70% for street cutting and repair).

Q. What range of replacement costs has the Company been experiencing?

A. In the past two years, unit replacement costs for main pipe have ranged from $69 to $83 per foot. These costs, which are due in part to the more restrictive street cutting, backfilling, patching and repaving policies explained above, are higher than the preliminary estimates made at the time Avista developed its Aldyl A Protocol. And if they persist, these higher unit costs will substantially increase the overall cost of the program.

Q. What steps is Avista taking to better understand and manage these costs?

A. The Company recognizes the need to continue to assess and forecast trends in unit costs and to understand and, to the extent possible, manage these factors. A key approach is focused on optimizing the specialized construction capabilities of Northern Pipeline to help Avista avoid expensive street cutting and repair costs. Another effort is directed to working with local authorities to explore street repair solutions that are less costly than current requirements, and in the meantime, targeting replacement activities in areas where the pipe replacement does not require pavement cutting.

Q. Has the Company provided details of the current and expected capital investment it is seeking to recover in this case?

A. Yes. The capital investment for the Project is referenced on pages 11 and 12 of the direct testimony of Company witness Mr. DeFelice, and these costs are included in the revenue requirement as noted on page 6 of the direct testimony of Company witness Ms. Andrews.

II. CUSTOMER SERVICE INFORMATION SYSTEM REPLACEMENT

Q. Please summarize the ongoing replacement project for Avista's Customer Information System?

A. Avista's legacy Customer Information System (System) has served the Company and our customers well for nearly 20 years. The term 'legacy' applies to computer hardware and software systems like Avista's that are no longer manufactured, used in contemporary applications, commercially available, or technically supported. The longevity of the Company's legacy system is unusual in the industry, and has been achieved by linking the system over time with commercial and Avista-developed applications that added functionality to the original architecture. This technology strategy has been the foundation of Avista's customer service program. While extending the life of the System has delivered value for customers, our ability to continue to add additional functionality is constrained, and there is mounting business and service risk associated with the many older technologies on which this system depends. Technical assessments of the System highlighted these risks, as well as identifying the pending need for its replacement. In 2010, Avista began the research and planning for replacing its legacy System. The replacement effort, named "Project Compass," was planned for a four-year period. An overview of Project Compass, containing a detailed project narrative, as well as supporting documentation, is provided as Exhibit 502.

Q. Please describe the systems being replaced as part of Project Compass?

A. Avista's legacy Customer Information System is composed of three highly-connected applications, which include:

- Customer Service System – this application supports the traditional utility business functions of meter reading, customer billing, payment processing, credit, collections, field requests and customer service orders;
- Work Management System – this application is used to create orders for service and emergency calls and for construction jobs for customers and Company operations; and
- Electric & Gas Meter Application – this application hosts the data for the Company's in-service electric and gas meters.

Together, these three applications, also referred to as the Avista "Workplace", have been connected over time with many other applications and systems required to conduct all aspects of our customer service and gas and electric business operations. These three Workplace applications are being replaced by Oracle's 'Customer Care & Billing' solution, and IBM's 'Maximo' asset management application.

Q. What are the factors driving the need for replacement of Avista's Customer Information System?

A. The rapid evolution of information science technologies has impacted the life cycle availability of older software and hardware products and services, eroding the underlying integrity of our legacy technology. At the same time, each new generation of technology gives software systems more flexibility and functionality than our legacy system could easily provide. This dual impact adds cost, complexity and risk to the ongoing operation of our legacy technology, and drives the ever-increasing service expectations of customers for all businesses they use, including their utility.

Q. Please describe what you mean when you say 'eroding the underlying integrity' of the Company's legacy technology?

A. The Company's legacy system is supported by a network of older technologies, many of which are expensive to operate and/or are no longer sold, maintained or supported. As a result, Avista and its primary support contractor (Hewlett-Packard) employ many technical 'workarounds' required to continue using the legacy System. Key limitations associated with these technologies are briefly described below:

<u>Platform</u> – The Company's Customer Information System is dependent on a mainframe-computing platform because it uses databases and program applications developed for that environment. While a mainframe was the only platform with enough power to support the System when it was designed, it is more expensive to operate today than mid-range computers with ample capability to support a similar sized system. Because mainframe platforms are far less common today, the expertise required to manage, maintain and update these systems is becoming more limited. In addition to the realtime execution of programs on the mainframe, required by the Workplace applications, the programs and data stored there must be updated every night in what is known as a 'batch' program. The batch updates base data and performs other functions such as producing customer bills.

<u>Computer Languages</u> – Avista's Workplace applications are written in COBOLv2, a mainframe-dependent programming language that has not been used in applications, or sold or supported for many years. In addition, this language is not compatible with current mainframe operating systems. Consequently, for many years the Company has used another software application, Micro Focus COBOL, to create a

virtual transcription of the original code into a more contemporary language that is mainframe compatible. This process results in some errors to the program code that are unavoidable with this technology, which necessitates additional processing to find and eliminate them each time this replication is performed.

Another computer language key to Avista's legacy system is known as Smalltalk. This language is used to generate the display information on network computers used by our customer service representatives. And like COBOLv2, Smalltalk is also no longer sold or supported.

Supporting Applications – When Avista's legacy applications require repair or modification to add functionality, the original programming language can only be changed using a specialized software product known as Application Development Workbench, or ADW, which is no longer manufactured or supported. In addition, ADW can only run on the OS/2 operating system that likewise has not been sold or supported for many years.

Technical Resources – Maintaining the Company's legacy system requires training and support of technical staff competent in these older programming languages, applications, and computer operating systems. The Avista-Hewlett-Packard support staff, many of whom grew up with these legacy technologies when they were mainstream, have either retired, or are anticipated to do so in the next few years. Replacing knowledgeable staff has become extremely difficult because there is no longer technical training or schooling available for these old languages, applications and systems. Younger technicians must be trained in house, and in addition, it is difficult to channel these employees into career tracks that have very-limited and diminishing future application.

Aldyl A Pipe Replacement and Project Compass

Q. Are there risks associated with the continued operation of the Company's legacy system?

A. Yes, as described above, many of the obsolete elements of the Customer Information System are supported by very-specialized applications, which themselves are obsolete and no longer supported, or by complex technology workarounds. Each of these introduces a level of risk that is greater than that associated with contemporary hardware, operating systems, technical support, and business applications. And because these risks increase as the technology continues to age, the cumulative risk to the Company grows as the longevity of the System is extended.

Q. Are these risks unique to Avista's legacy system?

A. No, this discussion illustrates the general technology principle shared by many legacy systems like the Company's. Even though they may continue to perform their intended functions, they are subject to greater and greater risk over time, and consequently, are considered to be problematic.

Q. Beyond increasing business risks, are there other considerations for replacing the system?

A. Yes, there are several which I describe below:

System Modifications – The legacy architecture of the Company's System makes it cumbersome and expensive to modify or to add new functionality. This arises because the linkages between the applications of Avista's Workplace, along with the software applications that connect Workplace with the many other applications and systems required to support the Company's operations, are 'hardwired' together. The result is that a programming change made to one application often requires complementary changes in both the connecting software and the other applications themselves. Because the system has been stretched over time so far beyond its original design considerations, these layers of changes have geometrically increased the complexity of the entire system. Finally, because the legacy System is used only by Avista, these application development costs must be borne entirely by our customers.

System Replacement Costs – Continuing to add complexity to the legacy System can also make its eventual replacement more expensive. This is because the functionality that's been programmed into the legacy System must also be programmed or 'configured' in the new replacement applications when they are installed. Generally, as the complexity of the legacy System increases, then the cost, complexity and technical competence required to install the replacement system increases as well.

Constrained Capability – In addition to the risks and costs of extending its service life, the ultimate flexibility of the platform has been largely exhausted. Designed as a meter-based billing system, the Company has cost-effectively expanded its capability by seamlessly integrating technologies barely imagined when the system was designed; home computers were uncommon, the internet was in its infancy, there were no e-mail services, few cell phones, no text or SMS messaging, and no mobile computing, as supported by today's smart phones and tablets. However, while the System has been able to accommodate many significant developments over time, it still lacks the fundamental capabilities required today to support the new service options viewed by customers as 'basic service', or the many utility product offerings becoming more common in our region and around the Country.

Q. Did the Company consider other options to reinforce its legacy System, short of replacement?

A. Yes. Periodically, Avista and its support partner, EDS/Hewlett-Packard, evaluated the System's capabilities as well as options for its possible modernization. In 2002, as some of the technologies supporting Avista's System, such as ADW, were becoming unsupported, an assessment was made of the feasibility of moving the Company's system from the mainframe platform to a contemporary mid-range platform and operating system. The benefits of such a process, commonly known as 'replatforming', were forecast over time and were compared with the estimated costs for completing the work. Results of this work indicated that replatforming the System at that time was not cost-effective, and as a result, this work did not proceed.

The next assessment was made in 2003 and focused on ways to reduce the risk associated with the ADW application, at the time running on aging desktop computers using the OS/2 operating system. The project report recommended Avista purchase specialized software to emulate the OS/2 system on contemporary computers and operating systems. This recommendation was implemented.

The legacy System was reviewed again in 2006 as part of a larger information technology review conducted for the entire Company. The report noted the Company's Customer Information System as a 'high risk' application that was a candidate for either replacement or "refactoring." The latter refers to a process of changing the internal structure of the existing application code to reduce its complexity and improve its readability. While this process helps reduce the risk associated with legacy software, it does not markedly change its basic properties or performance. Refactoring of the Customer Service System was not evaluated further at that time.

Most recently, in 2010, the Company again considered reinvesting in its legacy System as a means to delay its ultimate replacement. As a prelude to requesting vendor proposals to support such an effort, the Company sent a Request for Information to several major information technology vendors to describe the legacy System, and to gauge their interest in participating in next steps. As Avista continued to weigh the possibility of this approach being feasible, as a way to delay the replacement of its System, it ultimately determined that commencing with the research and planning for the current replacement project was a prudent course of action.

Q. Why did Avista consider the current timing of the replacement project to be appropriate?

A. The decision on timing was influenced by many factors, including, among other considerations: the window of availability of employee and contract technical resources; the timing of the expiration of the long-term services contract with Hewlett – Packard for System support; the continued accumulation of business and service risks associated with operating the legacy System; the increasing complexity and replacement costs associated with its continued operation, and the very-limited capability of the legacy System to deliver additional customer service options, both present, and into the future.

Q. Is the Company's replacement project unique among peer utilities?

A. No. Nationwide, many utilities have undertaken the same approach in replacing their Customer Information Systems, and many are replacing systems installed around the year 2000, a 'generation' even newer than Avista's. Several utilities in the Northwest are among those engaged in some phase of a major replacement project. Avista's understanding of the status of these efforts is summarized below:

Company	State(s)	Status
Cascade Natural Gas & Intermountain Gas	OR/WA/ID	Currently using Oracle's Customer Care & Billing application in Oregon and Washington, which replaced their prior system installed in 1999. Planning to install this system in their Idaho service area in late 2014-2015.
Northwest Natural Gas	OR/WA	Currently using commercial system installed around year 2000. Now in the process of evaluating potential for upgrades and/or system replacement in near future.
Puget Sound Energy	WA	Recently placed in service new SAP and Outage Management applications in April 2013. Now engaged in system stabilization.
Portland General Electric	OR	Beginning evaluation phase for the replacement of their customer information and meter data management applications, expected to be completed in next 5 years.
Idaho Power	ID	Planning to place in service a new SAP customer information system in September 2013.
PacifiCorp	ID/OR/WA	Currently evaluating systems for possible installation over the coming five years.
Seattle City Light	WA	Engaged in the early installation work of their recently selected Oracle Customer Care & Billing system.

Q. Did the Company assess the experience of others to avoid some of the pitfalls associated with replacing these large information technology Systems?

A. Yes. The Company took advantage of shared industry knowledge, reviewed case studies, and conducted its own in-depth interviews with several peer utilities to gather a base of 'lessons learned.' This pre-project research helped Avista identify and incorporate key measures into the design and management of its replacement project, to both circumvent and help mitigate these challenges.

Q. What initial steps did the Company take in researching and evaluating potential replacement software solutions?

A. An early step involved retaining a firm with proven expertise in this discipline to assist the Company with the complex process of developing a detailed list of business requirements and then evaluating and selecting the right combination of products and vendors to best meet them. A detailed request for proposals was developed from this initial work and sent to leading application and services vendors in September 2010. Avista selected Five Point Partners[4] from those firms submitting proposals.

Q. What additional activities were required to support this evaluation?

A. The Company completed a comprehensive inventory and evaluation of each existing Customer Information System work process, known as the Current State Map. The purpose of this work was to ensure that every work process in the business, and every technology requirement needed to support it, was identified and included in the technical specifications that accompanied the Request for Proposals sent to vendors. The current-state map included over 200 work processes and approximately 3,500 individual process steps or system requirements.

Q. What replacement applications did Avista select?

A. With the assistance of Five Point Partners, responsive proposals were evaluated and scored against a broad range of detailed criteria forming the basis of Avista's final selection of vendors. The systems selected were Oracle's Customer Care & Billing application to replace our legacy Customer Service module, and IBM's Maximo asset management application to replace the Company's Work Management System and its Electric and Gas Meter Application. Together, these two new applications would replace the Avista Workplace environment.

Q. When did the actual replacement activities begin?

[4] Five Point Partners is a consulting organization serving the utility, mining, revenue management, and transportation industries, offering a full life cycle of highly-focused enterprise consulting services from IT assessment and analysis, to implementation and post go-live support services.

A. When the selection process had closed, planning continued for the Implementation Phase. Final purchase agreements for selected software applications and 'integration services' were negotiated with vendors and signed in May 2012.

Q. What is Avista's budget for the overall replacement project?

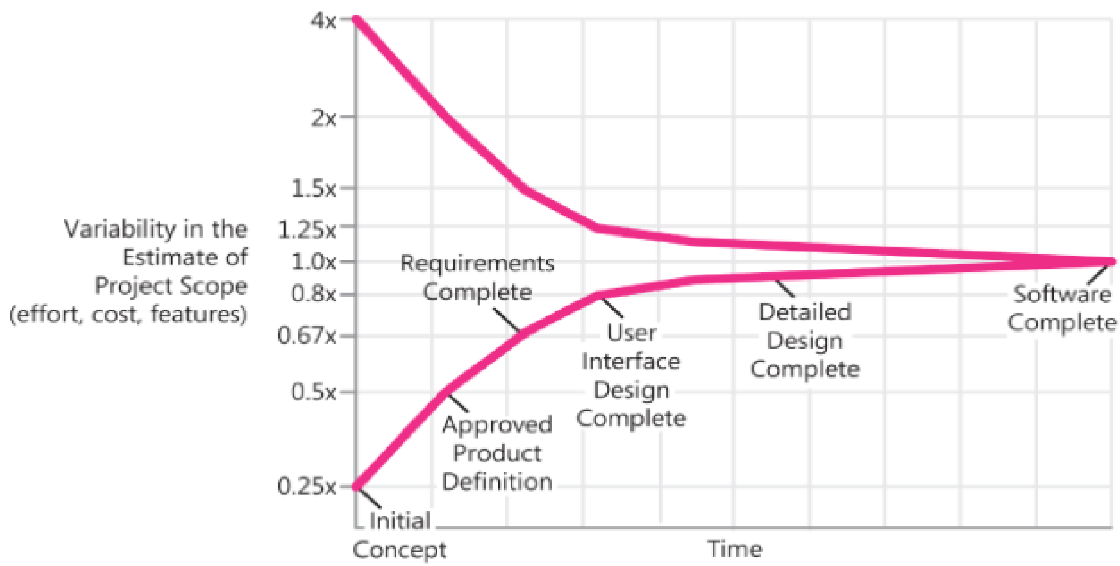
A. A final project budget was approved on December 6, 2012 for the overall capital replacement costs associated with Project Compass. The budget amount, including the initial allocation among key Project activities, is provided in Exhibit 502, Confidential Attachment 15.

Q. Why didn't the Company authorize a final project budget at the time it decided to replace its legacy System?

A. Although Avista discussed potential costs of the project early in its inception, and approved preliminary budgets through the course of Project development, it did not establish a final capital budget until the Project was well-enough defined to do so with confidence. Avista has learned through its peer utility interviews, and from the support and advice of outside experts, that organizations commonly undermine the success of their software projects by making cost commitments too early in the development stages. This mistake undermines predictability, increases risk and project inefficiencies, and generally impairs the ability to manage a project to a successful conclusion.

Q. Is this typical of enterprise software projects?

A. Yes. Typically, early in the scoping of a software project, particular details of the application being designed/installed, detailed knowledge of the Company's specific business requirements, details of the solution sets, as well as the management plan, identified staffing needs, and many other variables are simply unclear. Accordingly, estimates of the potential cost of the project are highly variable. As these sources of variability are further investigated and resolved, the uncertainty in the project decreases; likewise, so does the variability in estimates of the project cost. This phenomenon, widely discussed in the literature and often associated with author Steve McConnell[5], is known as the "Cone of Uncertainty", presented in Figure 1[6], below.



As the figure illustrates, significant narrowing of the uncertainty generally occurs during the first 20-30% of the total calendar time for the project. The uncertainty will only decrease, however, through deliberate and active project research and design, required to further define the scope, requirements, implementation details and estimates of component costs. And, this uncertainty must continue to be constrained throughout the course of the project by the use of effective project controls.

[5] Software Estimation: Demystifying the Black Art. Steve McConnell, Microsoft Press, 2006

[6] id. Figure 4.2, 96.1/751.

Q. In light of this cost uncertainty, how could Avista determine that replacing its legacy system was 'cost effective' for customers well before the final project scope and budget were developed?

A. The decision point for the Company in 2010 was whether to significantly reinvest in its legacy technology as the means to defer its ultimate replacement, or instead, to invest in the planning and exploration of options needed to support its replacement. The Company determined, as explained in more detail in Exhibit 502, that it was time to replace the System. The Company's focus then was to assess its needs, evaluate options, and select a set of solutions that would meet the long-term needs of the Company and its customers at the lowest possible cost. At that point, the Company engaged in the progressive stages of project design needed to prudently define its likely scope and potential cost. Through this work, uncertainty around the project was narrowed and potential costs were further refined, to the point that Avista was confident purchasing the selected applications and proceeding with the work of implementation. Even though this was several months before the final budget was approved, Avista had by this time built the foundation needed to initiate a successful project: the ability to deliver a solution that would meet its long-term customer service and business requirements in an optimized approach, and in a manner that would achieve the least cost for its customers.

While Avista believes its estimates of scope, timeline and budget for the project are reasonable, and is committed to control the Project to best meet each estimate, it is also cognizant that its success will not be defined by whether or not each estimate, including the budget, is precisely met. In contrast with a 'not-to-exceed' metric, the software budget is a management tool that allows senior leaders to make informed enterprise-level decisions, and that provides an effective tool for the project manager to control project activities in an effort to meet the estimates of each deliverable (timeline, scope, functionality, and cost). In describing the relationship between software project estimates and final results, McConnell states:

> "The primary purpose of software estimation is not to predict a project's outcome; it is to determine whether a project's targets are realistic enough to allow the project to be controlled to meet them."[7] "Typical project control activities include removing noncritical requirements, redefining requirements, replacing less-experienced staff with more-experienced staff, and so on."[8] "In practice, if we deliver a project with about the level of functionality intended, using about the level of resources planned, in about the time frame targeted, then we typically say that the project "met its estimates," despite all the analytical impurities implicit in that statement. Thus, the criteria for a "good" estimate cannot be based on its predictive capability, which is impossible to assess, but on the estimate's ability to support project success…[9]

Avista believes it has designed and developed such an implementation plan and budget for Project Compass. By this, we mean that the overall Project record will demonstrate its proper research and design, robust planning and estimating, effective management and controls, and that its delivered scope, timeline and cost, are reasonable, cost effective and prudent.

Q. What are the key activities currently underway in the Project?

A. Avista is currently in the Implementation Phase, which encompasses the activities of installing and configuring the new vendor software, and developing and delivering the specialized training modules for the new Systems. Configuring a software application involves the programming required to code its generic capabilities to

[7] id. At 42/751.
[8] id. At 39/751.
[9] id. At 41/751.

execute the steps needed to match each of the Company's work processes. In addition, there are many Avista process steps that cannot be executed within the generic capability of the new applications, without customization. This involves the addition of customized programming that is outside the bounds of the 'off the shelf' capability of the application. Significant customization renders the process of installing the periodic vendor updates of the applications, both complex and expensive. Avista is committed to capturing the value delivered by 'off the shelf' implementation, and accordingly, our goal is to minimize the need for customization. What this requires, however, is that Avista organize employee teams to accomplish the significant tasks of developing new internal business processes that are supported by the vendor application, as well as the work of developing the new employee training programs required to successfully implement the new processes. Work in this Phase also includes the significant programming required to integrate the new vendor applications with approximately 100 other applications and systems required to support the Company's customer service and allied business operations. Finally, this Phase of the Project encompasses the development of employee training programs and systems for the new applications, and the extensive testing of the system needed to confirm the technical performance of the new applications as configured to Avista's design.

Q. When will these new systems be 'used and useful'?

A. The final steps in the Implementation Phase involve 'migrating' the Company's customer service and business operations from the legacy systems and platform to the new applications and systems. The step of disabling the existing System and placing the new System into service is known as the "Go-Live." A portion of the Maximo asset management application will Go-Live in the fall of 2013, and the remainder of the Maximo application and the Oracle Customer Care & Billing System is expected to Go Live in July 2014.

Q. Are there any Project activities that continue after the new Systems are serving Avista's customers?

A. Yes. The Company will keep technical teams in place for approximately six to twelve months to support the new applications, information technology staff, customer service and other employees, and customers, in the activity known as "project stabilization."

Q. Has the Company provided details of the current and expected capital investment it is seeking to recover in this case?

A. Yes. The capital investment for the Project is referenced on page 8 of the direct testimony of Company witness Mr. DeFelice, and these costs are included in the revenue requirement as noted on page 6 of the direct testimony of Company witness Ms. Andrews.

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

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 501

Aldyl A Natural Gas Pipe Replacement and Project Compass

Avista Utilities Asset Management

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

February 23, 2012

www.avistautilities.com

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Executive Summary

Avista Utilities (Avista) is proposing to undertake a twenty-year program to systematically remove and replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system in the States of Washington, Oregon and Idaho. None of the subject pipe is "high pressure main pipe," but rather, consists of distribution mains at maximum operating pressures of 60 psi and pipe diameters ranging from 1¼ to 4 inches. As part of this program, Avista will re-make connections of select Aldyl A service piping, ½ and ¾ inch diameters, where tapped to steel main piping. Further, Avista notes that while there have been concerns with the integrity of steel pipe in other parts of the country in recent years, the steel pipe in its system, including steel service risers, is being managed to protect its long-term reliability and performance and is outside the scope of this program.

In recent years, Avista experienced two incidents on its natural gas system that prompted the Washington Utilities and Transportation Commission and the Company to better understand the potential long-term reliability of Aldyl A pipe. Results of these investigations, which were aided by new tools developed for Avista's Distribution Integrity Management Plan ("DIMP" or "Integrity Management"), corroborated reports for similar Aldyl A piping around the country as supporting the development of a protocol for the management of this gas facility. The following report highlights the history of DuPont's Aldyl A natural gas pipe and summarizes DuPont and Federal Agency communications that are relevant to this proposed program. The report documents the Aldyl A pipe in Avista's natural gas system and describes the analysis of the types of failures observed in this pipe, and the evaluation of its expected long-term integrity. Finally, the report describes the results of Avista's work to establish the framework for the proposed protocol for the management of Aldyl A pipe in its natural gas system.

Table of Contents

I. History of DuPont Aldyl A Piping Systems

Modern polyethylene pipe products are corrosion-free, lightweight, cost-effective, highly-reliable, and can be installed quickly and efficiently. For these reasons, it has for decades been the 'standard for the industry' and is the predominant choice used in natural gas distribution systems. As with any revolutionary product line, polyethylene piping systems have undergone continuous and rigorous testing and product improvement. Such is the case with DuPont's Aldyl A piping systems, as very briefly summarized below.

DuPont Introduces Natural Gas Polyethylene Pipe – 1965

Along with other manufacturers, DuPont began to use polyethylene resin to produce plastic piping for a variety of purposes. The resin was produced from ethylene molecules combined together in repeating patterns to form larger molecules called 'polymers', hence the name 'polyethylene.' DuPont's product designed specifically for use in the natural gas industry was marketed under the name "Aldyl A." The initial resin used in production of Aldyl A pipe, Alathon 5040, was manufactured from 1965 to 1970. DuPont changed the resin in 1970 to improve Aldyl A's resistance to rupture during pressure testing. This improved formulation, known as Alathon 5043, was the primary resin used in DuPont's Aldyl A pipe from 1970 until 1984.

The Phenomenon of "Low Ductile Inner Wall"

Shortly after changing its polyethylene resin in 1970, DuPont detected a manufacturing issue highlighted during laboratory testing of Aldyl A pipe. DuPont learned that its manufacturing process was resulting in some of the pipe having a property described as "Low Ductile Inner Wall." "Ductility" is the ability of a material to withstand forces that alter its shape without it losing strength or breaking. A 'highly-ductile' material can be bent, flexed, pressed or stretched without cracking or losing strength because, unlike brittle materials, it can redistribute the forces of stress concentration. Low Ductile Inner Wall, or as it often appears "LDIW," results when the inner surface of the Aldyl A pipe becomes brittle, promoting the formation of cracks and premature failure. In early 1972, DuPont changed its manufacturing process to eliminate this phenomenon, but estimated that 30 – 40% of the pipe it produced in 1970, 1971 and early 1972 was affected, primarily in pipe diameters from 1¼ inches to 4 inches.

DuPont Communicates Potential Issues to Aldyl A Customers

1982 Letter

In 1982, DuPont sent a letter to its natural gas customers, noting that two of its gas utility customers had reported a low frequency of leaks in Aldyl A pipe manufactured prior to 1973 (See Attachment 1). These leaks were reported as "slits" occurring where the pipe was in "point contact with rocks." DuPont noted these two utilities had increased the frequency of leak surveys where rock may have been part of the backfill around the pipe, and encouraged other Aldyl A customers to consider the same. This letter was the genesis of what would become a continuing focus on the pipe vintage known as "pre-1973 Aldyl A."

1986 Letter

DuPont's second letter to its Aldyl A pipe customers was sent in 1986, focusing again on pre-1973 Aldyl A pipe (See Attachment 2). The letter focused on results of newly-developed (elevated temperature) testing methods that allowed DuPont to more-accurately estimate the longevity of this vintage pipe, in diameters of 1¼ inches and larger. Test results showed that 'Aldyl A pipe manufactured prior to 1973 had certain limitations that were not previously-shown by then-available, state-of-the-art testing methods.' The limitations were described as a reduction in pipe service life caused by: 1) "rock impingement" or pressure from rock points directly on the pipe (as mentioned in their 1982 letter), and 2) the use of squeeze-off practices. The term "squeeze-off" refers to the current and long-standing construction practice of mechanically pressing in polyethylene pipe walls to temporarily stop the flow of gas during work on a line that is in service. DuPont further noted that average ground temperature surrounding the pipe, in the ranges of 60 to 70 degrees (F), had a major bearing on its ultimate expected service life. Finally, DuPont recommended that operators should reinforce the pipe, using clamps that surround the pipe at squeeze points, in order to extend the life of its Pre-1973 Aldyl A.

DuPont Substantially Improves Aldyl A Pipe

DuPont made a significant change to its Aldyl A resin formulation in 1984. The improved resin, known as Alathon 5046-C, was marketed as "Improved Aldyl A", and significantly improved the performance of Aldyl A pipe in its resistance to 'Slow Crack Growth' and overall long-term integrity. Slow Crack Growth, or as it's often abbreviated, SCG, describes the progression of a crack that begins with 'crack initiation' or the formation of a crack in the inner wall of the pipe. The crack then progresses through the pipe wall, usually over period of many years, until it finally breaks through the outer surface of the pipe, resulting in failure.

Again, in 1988, DuPont announced another advance in its Aldyl A pipe resin with the introduction of Alathon 5046-U. This change in resin formulation increased the resistance of the pipe to slow crack growth by another order of magnitude. In addition, because of the high 'molecular efficiency' of this new resin, its density was also reduced, which allowed for much greater ductility in the pipe. This product, the last of the DuPont Aldyl A materials that Avista would install, was also marketed as Improved Aldyl A. A summary of DuPont Aldyl A pipe produced between 1965 and 1992 is presented below in Table 1. Information includes the year of manufacture, resin formulation, relative resistance to slow crack growth (stress rupture testing at 80° C / 120 psig for accelerated life testing), and summary notes.

Table 1. DuPont Aldyl A Pipe 1965 - 1992

Years of Manufacture	Resin	Rupture Resistance*	Notes
1965 - 1970	Alathon 5040		Initial Product Marketed as "Aldyl A"
1970 - 1972	Alathon 5043	10 hours	Resin Improvement and Low Ductile Inner Wall
1970 - 1984	Alathon 5043	100 hours	Resin Improvement
1984 - 1988	Alathon 5046-C	1000 hours	Resin Improvement-- Sold as "Improved Aldyl A"
1988 - 1992	Alathon 5046-U	10,000 hours	Resin Improvement --"Improved Aldyl A"

*Illustrates the order of magnitude difference found from accelerated life testing of resins

Common Classifications of Aldyl A Pipe

Based on the characteristics of the different vintages of Aldyl A pipe, there would emerge over time, from DuPont's 1982 letter going forward, three age-groupings recognized by the manufacturer, natural gas industry, and regulators as relevant in the reliability management of this pipe.

Pre-1973 Aldyl A – Pipe manufactured through 1972, from the first two resin formulations, and including pipe having low ductile inner wall.

Pre-1984 Aldyl A – Aldyl A pipe manufactured from Alathon 5043 resin, but only that pipe manufactured after 1972 and through 1983.

1984 and Later Aldyl A – Pipe manufactured from the improved Alathon 5046-C and 5046-U resins.

Aldyl A Service Pipe - Small-diameter (less than 1¼ inches) Aldyl A service piping is often treated or managed differently than larger-diameter Aldyl A pipe of the same vintage. This is because the small-diameter pipe has been assessed by industry experts as being more resistant to brittle-like cracking than larger-diameter pipe due to its greater flexibility. Further, small-diameter Aldyl A pipe has been confirmed as being free of the Low Ductile Inner Wall properties present in late 1970 through early 1972 vintage piping.

II. Federal Bulletins on Brittle-Like Cracking in Plastic Pipe

National Transportation Safety Board

In April 1998, twelve years after DuPont's second letter to customers, the National Transportation Safety Board (Board) published a comprehensive safety bulletin describing their investigation of natural gas pipeline accidents involving polyethylene pipe that had cracked in a "brittle-like" manner (See Attachment 3). The bulletin focused primarily on accidents related to an early plastic pipe manufactured by Century Utility Products (Century), produced from Union Carbide resin. In its review, findings, and in its Safety Recommendations, however, the Board concluded that in addition to the Century pipe, much of the polyethylene pipe produced for gas service from the 1960s through the early 1980s may be susceptible to brittle cracking and premature failure, further noting that vulnerability of this material to premature failure could represent a serious potential hazard to public safety.

The Board's bulletin represented a seminal work on the vulnerability of early plastic pipe to brittle-like cracking because it analyzed and integrated – for the first time – reports from the technical literature, manufacturers' communications, industry expert opinions, the experience of pipeline operators and regulators' accident reports. Because the bulletin provided a clear understanding of the drivers of failure in older polyethylene pipe, we have included a fairly detailed synopsis in this report.

Objectives of the Board's Investigation

Following the Board's investigation of over a dozen serious incidents, it undertook an effort to evaluate whether the existing pipeline accident data was sufficient for assessing the long-term performance of plastic piping. The office of Research and Special Programs Administration of the National Transportation Safety Board compiled the relevant accident data, but found it to be insufficient for this purpose. Lacking adequate data for the larger assessment, the Board instead focused on estimating the likely frequency of brittle-like cracking, focusing on published technical literature, industry expertise, and work with several gas system operators. From this review, the Board launched a special investigation with the objectives to address three safety issues related to polyethylene gas service pipe:

1. Vulnerability of plastic piping to brittle-like cracking
2. Adequacy of available guidance to pipeline operators regarding installation and protection of plastic pipe tapped to steel mains
3. Performance monitoring as a possible way to detect unacceptable performance in piping systems

Phenomenon of Premature Brittle-Like Cracking

The Board's survey suggested that early plastic piping may be "susceptible to premature brittle-like cracking under conditions of stress intensification." The term 'stress intensification' refers to localized pressure on the pipe wall created by such conditions as rock contact or significant bending of the pipe. The phenomenon of brittle-like cracking was characterized by the failure processes described above, beginning with the initiation of cracks on the inner wall of the pipe at the pressure or stress point, followed by slow crack growth that progressed under normal pipeline operating pressures (much lower than the pressure required to rupture the pipe). The process culminated with the crack reaching the outside wall of the pipe, showing up as a very tight, slit-like opening on the surface, running generally parallel with the length of the pipe. Premature brittle-like cracking was believed, at the time of the Board's safety bulletin, to require relatively high and localized stress on the pipe resulting from sharp or excessive bending, soil settling, rock "impingement" (point or contact pressure on the pipe), improperly installed fittings, and dents or gouges to the pipe surface. The term 'brittle-like cracking' was used to describe this failure process because the pipe showed no signs of being bulged or deformed where the cracks occurred.

Board Findings on the Three Identified Safety Issues

Issue 1: Vulnerability of Plastic Piping to Brittle Cracking

Long-Term Strength of Early Pipe was Overrated - In the early 1960s the industry had very little long-term experience with plastic pipe, and consequently, developed laboratory testing procedures to forecast the expected service life of piping. Early testing results suggested that polyethylene pipe would exhibit a relatively constant, or 'straight line' gradual decline in strength over time. These tests and underlying assumptions were subsequently incorporated as standards for the industry and in related federal requirements.

As the industry gained experience, however, the straight-line assumptions of these early procedures began to be challenged through the development of new testing methods, where pipe strength was assessed under conditions of elevated temperature (such as the testing referenced in DuPont's 1986 letter to customers). Results of the elevated-temperature testing showed that the decline in strength of early plastic pipe was not gradual or linear as had been assumed, but instead, began to accelerate or drop below the straight line, especially after twelve years. The Board concluded that the early testing procedures may have overrated the strength and resistance to brittle-like cracking of the polyethylene pipe manufactured for the gas industry from the 1960s through the early 1980s.

Long-Term Ductility was Overrated - Another important assumption about early plastic pipe, based on short-term testing, was that it would retain its ductile properties long term. The assumption of long-term ductility had important safety ramifications since it allowed plastic pipe systems to be designed to withstand stresses generated primarily by internal pressure and to give less consideration to the impacts of external stresses such as bending. Unfortunately, the early testing methods did not properly identify the evidence of the "ductile to brittle" transition that was occurring early in the life of the pipe. Consequently, the tests did not distinguish pipe failures resulting from a loss in ductility. The Board noted that this loss of ductility was also observed in the older piping of several manufacturers, those other than Century Utility Products.

Pipeline Operators had Insufficient Notification - The Board noted that premature brittle-like cracking was a complex phenomenon that had not been systematically communicated to the industry, and hence, had not been fully-appreciated by pipeline operators. The Board recognized pipe manufacturers as commonly offering technical and safety assistance to operators, and occasionally, formal reports on their materials. But, because the information on the potential weakness of their products was also mixed with information publicizing its best performance characteristics, the message was not clear. The Board also noted that the Federal Government had not provided relevant information to gas system operators, and concluded that operators had insufficient notification that much of their early polyethylene pipe may have been susceptible to premature brittle-like cracking. Finally, the Board went on to recommend that the polyethylene pipe manufacturers' organization, the Plastics Pipe Institute, advise its members to notify pipeline operators if any of their materials indicate poor resistance to brittle-like failure.

Issue 2: Adequacy of Guidance for Connecting Plastic Pipe to Steel Mains

Critical Understanding of Stress on Pipe - The Board observed that the premature transition of plastic piping from a ductile to a brittle state appeared to have little observable adverse impact on the serviceability of plastic pipe, *except* where the pipe was subjected to external stresses, such as excessive bending, earth settlement, dents or gouges to the pipe surface, and improper installation of fittings, etc. Of those sources of stress, a key factor identified in the Board's bulletin was earth settlement, but particularly in cases where plastic piping was connected to more rigidly anchored fittings, such as steel main pipe. Because the physical properties of plastic and steel respond differently under the same conditions, such as to temperature change and ground settlement, the slight movements of each type of pipe in the ground will be different. This difference in movement can result in significant stress at the point of connection between the plastic and steel piping.

Much of the Guidance to Operators was Insufficient or Ambiguous - In addition to pipeline operators having insufficient guidance on the overall issue of the vulnerability of plastic pipe to brittle cracking, as noted above, the Board also observed that much of the available guidance to operators on how to limit stress on the pipe during installation was inadequate or ambiguous. This was particularly the case with the stress associated with the tapping of plastic service piping to steel mains, where the Board concluded that many of those connections may have been installed without adequate protection from external stress. The Board went on to identify several instances where safety requirements did not fully incorporate safety recommendations, resulting in ambiguity for pipeline installers and regulators. Other highlights of the Board's findings were the many cases where the applicable regulations applying to pipeline installation lacked any performance measurement criteria. Noting that the Office of Pipeline Safety considered many of its safety regulations to be performance-oriented requirements, the Board rebutted this in stating that “many are no more than general statements of required actions that do not establish any criteria against which the adequacy of the actions taken can be evaluated.” A particular example was the regulation that “requires gas service lines to be installed so as to minimize anticipated piping strain and external loading,” and yet it contained no performance measurement criteria for establishing compliance. Finally, the Board went on to note cases where the inadequacy of pipe manufacturers’ instructions also contributed to the lack of a clear understanding of methods to limit stress on plastic pipe during installation.

Issue 3: Monitoring of Plastic Pipe to Determine Unacceptable Performance

The Board’s final objective was focused on performance monitoring of pipeline systems as the key to effectively managing the vulnerable piping types identified in the bulletin. In this discussion, the Board focused on the accident in Waterloo, Iowa in 1994[1], in highlighting the very real challenges of designing effective pipeline monitoring programs. The Board stated that before the accident, the pipeline operator had developed a limited capability to monitor and analyze the condition of its system. It concluded however, that the systems the operator had developed for tracking, identifying, and statistically treating plastic piping failures did not permit an effective analysis of system failures and leak history, noting that their methods of handling of pipe data masked the high failure rates of the subject Century pipe. While the operator did re-evaluate its monitoring data after the accident, and subsequently identified the high failure rates of Century Pipe, the Board opined that the problem could have been detected earlier (before the accident) if the data had been properly analyzed in the first place. Finally, the Board concluded that an effective monitoring program would have allowed the operator to implement a pipe replacement program that might have prevented the accident.

In the second case, the Board noted that while the operator had added capabilities to its pipe-monitoring protocols, it had still not chosen parameters needed to provide adequate analysis of its plastic piping system failures and leak history. The bulletin went on to note examples of the many types of additional parameters needed to enable the effective tracking, identifying, and properly describing system failures and leak history.

The Board concluded that in light of the key findings in its bulletin, that gas system operators may need to be advised once again of the importance of complying with Federal requirements for piping system surveillance and analyses. Regarding the monitoring of older piping, the Board identified the necessity to analyze factors such as piping manufacturer, installation date, pipe diameter, operating pressure, leak history, geographical location, modes of failure, location of failure, etc. Finally, the Board noted that an effective monitoring program would require the evaluation of pipe material and installation practices to provide a basis for the planned and timely replacement of piping that indicates unacceptable performance.

[1] In October, 1994, a natural gas leak and explosion at Midwest Gas Company in Waterloo, Iowa, resulted in 6 fatalities and 7 injuries. The cause of the incident was identified as the failure of a ½ inch diameter service pipe cracking in a brittle-like manner at a connection to a steel main.

Pipeline and Hazardous Materials Safety Administration

1999 Bulletins

The first two of several advisory bulletins related to the Board's 1998 Safety Bulletin (above), were published by the Office of Pipeline Safety, now known as the Pipeline and Hazardous Materials Safety Administration (Administration), in March 1999 (See Attachment 4). The bulletins, which were issued as advisories to pipeline owners and operators, provided an abstract of the findings of the Board's 1998 investigation and advised that much of the plastic pipe manufactured from the 1960s through the early 1980s may be susceptible to brittle-like cracking. The advisories concluded with the recommendation to owners and operators to identify all pre-1982 plastic pipe installations, analyze leak histories, evaluate potential stresses to pipe, and to develop appropriate remedial actions, including pipe replacement, to mitigate any risks to public safety.

2002 Bulletin

This bulletin, as with the prior advisories, reiterated to natural gas pipeline owners and operators the susceptibility of older plastic pipe to premature brittle-like cracking (See Attachment 5). But, for the first time, this advisory specifically named DuPont's pre-1973 Aldyl A pipe (Low Ductile Inner Wall) as being susceptible to brittle cracking. The bulletin also depicted several environmental and installation conditions that could lead to premature, brittle-like cracking failure of the subject pipe, and described recommended practices to aid operators in identifying and managing brittle-like cracking problems.

2007 Bulletin

This bulletin, again, served to review and recap the findings of the prior bulletins, advising natural gas system operators to review the earlier statements (See Attachment 6). In addition, the advisory recapped results of the ongoing effort of the American Gas Association to identify trends in the performance of older plastic pipe. The advisory reported that the data, at that point, could not assess failure rates of individual plastic pipe materials, but did support what was historically known about the susceptibility of older plastic piping to brittle-like failure, including the addition of specific materials to the list, such as Delrin insert tap tees.

III. 2009 Distribution Integrity Management Program

The Administration published the final rule establishing integrity management requirements for gas distribution pipeline operators in December 2009. Though the effective date of the rule was February 2010, operators were given until August 2011 to write and implement their Distribution Integrity Management Plan.

Objectives and Approach

Among other objectives, the program was intended to overcome two key weaknesses in pipeline safety management that were identified in the National Transportation Safety Board's 1998 bulletin (above): 1) correct weaknesses in federal regulations, particularly in the Office of Pipeline Safety, by establishing true measurement criteria for establishing safety compliance, and 2) establish systematic protocols for pipeline data collection, analysis, and interpretation, that helps ensure accurate integrity assessment and appropriate remediation.

The concept of Integrity Management grew out of a demonstration project of the Office of Pipeline Safety designed to test whether allowing operators the flexibility to allocate safety resources through risk management was effective in improving pipeline safety and reliability. Integrity management requires operators, such as natural gas distribution companies, to write and implement Integrity Management Programs (IMPs) to assess, evaluate, repair and validate the integrity of pipeline segments. The program contains the following elements:

- Knowledge
- Identify Threats
- Evaluate and Rank Risks
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness
- Periodically Evaluate and Improve Program
- Report Results

The Integrity Management approach uses historical leak data and other facility information, along with the input of subject-matter experts, to identify individual threats to a gas system. These threats are then analyzed to predict the likelihood and consequences of failure. Each threat is then ranked by priority, followed by the development of a plan to reduce or remove those risks as deemed necessary.

IV. 2011 Call to Action – Transportation Secretary LaHood

Finally, in April 2011, U.S. Transportation Secretary LaHood issued a Call to Action to all pipeline stakeholders in conjunction with the effective application of the Distribution Integrity Management Program (See Attachment 7). The Call to Action was aimed at the more than 2.5 million miles of liquid and gas pipelines of both federal and state jurisdiction, including transmission and distribution facilities, calling on owners and operators, the pipeline industry, utility regulators and state and federal partners to:

- Evaluate risks on pipeline systems;
- Take appropriate actions to address those risks, and
- Requalify subject pipeline systems as being fit for service.

The centerpiece of the Call to Action is the "Action Plan" of the Board and Administration. The focus of the Action Plan is to accelerate the rehabilitation, repair, and replacement of high-risk pipeline infrastructure, calling on pipeline operators and owners to take "aggressive efforts… to review their pipelines and quickly repair and replace sections in poor condition." To buttress this Call to Action, Secretary LaHood has asked Congress to increase maximum civil penalties for pipeline violations, to close regulatory loopholes, strengthen risk-management requirements, add more inspectors, improve data reporting and help identify potential pipeline safety risks early.

V. Avista's Experience with DuPont Aldyl A Piping Systems

Avista has approximately 12,500 miles of natural gas piping in its service territories in the States of Washington, Oregon and Idaho. Like dozens of other gas utilities, Avista adopted plastic pipe as an excellent alternative to steel, and consequently, the broad majority of Avista's pipe is polyethylene (about 8,500 miles) of various types, ages and brands, including DuPont's Aldyl A.

Avista began installing DuPont Aldyl A in 1968 and discontinued its use in 1990 when DuPont sold their production to Uponor. Of the various vintages and formulations of Aldyl A pipe in its system, Avista has estimated quantities in the following amounts, in diameters of ½" to 4":

Pre-1973 Aldyl A (1965-1972 resins)	190 Miles
1973-1984 resins	960 Miles
1985-1990 resins	919 Miles

Avista noted the advisory bulletins of the Board and Administration in 1998, 1999 and 2002, but since it had no documented trends in the types of failures highlighted, continued to manage its Aldyl A pipe according to established monitoring standards for leak survey and sound operations practices.

Spokane and Odessa Incidents

In recent years, however, Avista experienced two natural gas incidents[2] resulting in injuries and property damage that signaled possible changes in leak patterns in its Aldyl A piping. The first incident occurred in 2005 at a commercial site in Spokane. This event involved the failure of 1976-vintage Aldyl A pipe caused by bending-stress resulting from poor soil compaction around the pipe that was performed by a non-Avista excavator in 1993. The post-incident investigation judged the resulting leak to be an anomaly that could have been prevented with proper care by that third-party excavator.

[2] The Pipeline and Hazardous Materials Safety Administration defines a natural gas "incident" as a release of gas that results in any of the following: a fatality or personal injury that requires in-patient hospitalization; property damage of $50,000 or greater, or the loss of greater than 3 million cubic feet of gas.

The second incident, at a residence in the town of Odessa, Washington, in late 2008, was determined to be the result of rock pressure on the 1981-vintage Aldyl A pipe that occurred during the initial installation. Avista signed a settlement agreement with staff of the Washington Utilities and Transportation Commission as an outcome of the investigation of this incident. Under terms of the agreement, which was subsequently approved by the Commission, Avista increased the frequency of its residential leak survey on pre-1984 resin (pre-1987 installed) Aldyl A natural gas mains in its Washington jurisdiction, from once every five years to annually. In addition, whenever it is excavating in the vicinity of Aldyl A natural gas mains in Washington, Avista will also report on the soil conditions surrounding the pipe, and identify appropriate and reasonable remedial measures, as necessary. Avista retained the consulting services of Dr. Gene Palermo to help develop its approach for managing Aldyl A pipe, in relation to the soil conditions reported.

Expert-Recommended Protocol for Managing Aldyl A Pipe in Relation to Reported Soil Conditions

Dr. Palermo is a nationally-recognized expert on the plastic pipe used in natural gas systems, and in particular, Aldyl A piping. He has worked in the plastic pipe industry for over 35 years, which includes 19 years with the DuPont Corporation in its Aldyl A natural gas pipe division.

Dr. Palermo also served as the Technical Director for the Plastics Pipe Institute from 1996 through 2003 and served on the Institute's Hydrostatic Stress Board for over 20 years. Dr. Palermo has served on a variety of gas industry committees, has trained gas industry practitioners and regulators, and has received numerous awards of merit for his outstanding individual contribution to the natural gas plastic-piping industry. He is the only person to receive both the American Society of Testing and Materials - Award of Merit, and the American Gas Association - Platinum Award of Merit. Dr. Palermo is president of his consulting firm, Palermo Plastics Pipe Consulting.

Dr. Palermo reviewed the content of Avista's settlement agreement with the Commission to become familiar with its requirements, specifically with regard to managing Aldyl A piping found in soils that would currently not meet standard criteria for bedding and backfill. Dr. Palermo's review and expertise provided the basis for his recommended protocol for management of Avista's Aldyl A piping found in rocky soils. (See Attachment 8):

1. All Aldyl A pipe manufactured prior to 1984 should be evaluated for replacement in the following manner:
    a. If the pipe has Low Ductile Inner Wall properties, Avista should immediately begin a prioritized pipe replacement program.
    b. If the pipe is installed in soil with rocks larger than ¾ inch, Avista should immediately begin a prioritized pipe replacement program.
    c. If the pipe is installed in sandy soil or in soil with rocks up to ¾ inch in size, the pipe should remain in service and normal leak surveys per DOT Part 192 should be followed.

2. All Aldyl A pipe manufactured during or after 1984 should also be evaluated.

    a. If the pipe is installed in soil with rocks larger than ¾ inch in size, Avista should evaluate the pipe and consider replacing it if they begin to experience rock impingement failures, and should conduct leak surveys more frequently than required by DOT Part 192, until replacement.
    b. If this pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys should be followed.

Evaluation of Leak Survey Records

Following the Odessa incident, Avista was also asked to review five years of leak survey records in Washington State to look for possible emerging patterns in the health of its Aldyl A piping system. Avista organized the leak survey information and then conducted several evaluations, which were organized under three general objectives, listed below.

1. Analyze the modes or observed types of failures in Aldyl A pipe;
2. Forecast the expected long-term integrity of Aldyl A piping;
3. Identify potential patterns in the overall health of this piping to aid in the design of a more-focused management protocol for Aldyl A pipe.

Avista used newly-available asset-management tools to conduct these assessments, including its recently-implemented Integrity Management approach for identifying and analyzing potential threats to its natural gas system. This approach is suited for just such an analysis, having the capability to determine potential patterns in the overall health of a piping system that might not have been otherwise evident through conventional data review. The analysis of the historic leak survey data, including the observation of several new Aldyl A material failures and leaks, did point to the development of a possible trend.

Pipe Replacement Projects in 2011

Another outcome of this heightened focus on Aldyl A leaks was Avista's decision to replace several thousand feet of its Aldyl A main in 2011. In Odessa, Avista increased the frequency of leak surveys on its gas system to once per quarter and mobilized a pipe replacement program that removed all of the pre-1984 Aldyl A main pipe from the gas system in the town. During that project, which was conducted from June to December 2011, nearly 32,000 feet of Aldyl A main pipe were replaced. Other Aldyl A replacement projects in 2011 removed an additional 7,000 feet of this priority pipe. Together, these projects had a capital cost of approximately $2.7 million.

VI. Avista Distribution Integrity Management Program

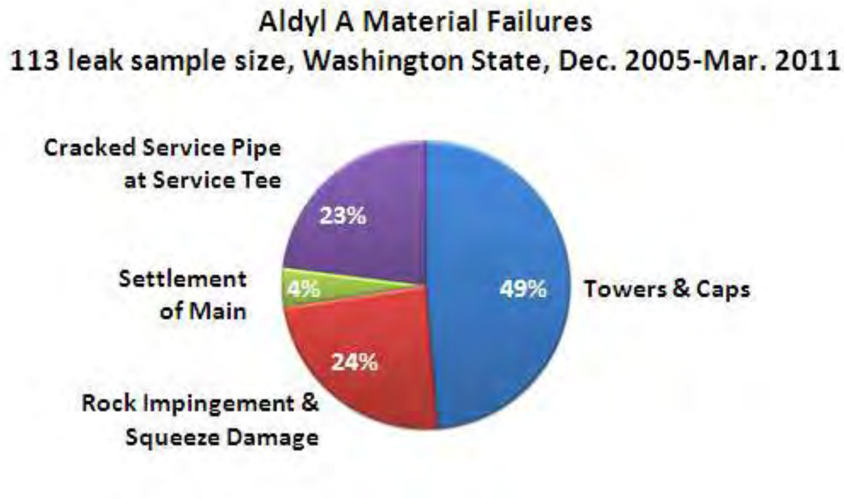
As described briefly above, the Integrity Management approach, now required by law, begins with the aggregation of historical leak-survey data and other facility information relevant to Avista's natural gas piping system. Then, in conjunction with the input of subject matter experts, individual threats to Avista's gas system are identified. These threats are analyzed to predict the likelihood and consequences of failure associated with each threat, based on the specific operating environment, system makeup, and history of Avista's natural gas system. Each threat is then ranked relative to all others to identify, by priority, those with the greatest hazard potential. From that priority list, measures are developed to reduce or remove those risks as deemed necessary. These mitigating measures are often referred to as "accelerated actions" because they may be above and beyond the minimum requirements of applicable federal and state codes. These accelerated actions can range from increased frequency of maintenance and leak surveys to full replacement programs for certain gas facilities. Finally, the mitigating measures will be reviewed to evaluate their effectiveness in reducing threats to the gas system, and the program will then be adjusted as necessary based on those outcomes.

Integrity Management requires the use of geographically-based analytical software to complete many of the required program elements. Like many utilities, Avista is using the Geographic Information System (GIS) platform developed and supported by Environmental Systems Research, Inc. (ESRI), as the geographic and analytical engine for conducting its gas system evaluations under the Integrity Management program. ESRI is a pioneer and world leader in developing and supporting geographic software products for a broad range of global business sectors, including utilities. Since Avista had already created a comprehensive GIS layer, or database, for its gas facilities, it made sense to add analytical capabilities to this platform in complying with the Integrity Management program requirements.

VII. Analyzing Modes of Failure in Avista's Aldyl A Pipe

In tackling the first objective of the assessment of its Aldyl A piping, Avista aggregated the gas leaks resulting from Aldyl A material failures found in its gas system in Washington State from late 2005 through March 2011. The sample included 113 material failures that were evaluated and summarized by component to offer an understanding of the specific failure modes for Aldyl A pipe. The 'modes' or types of material failures categorized are shown below in Figure 1.

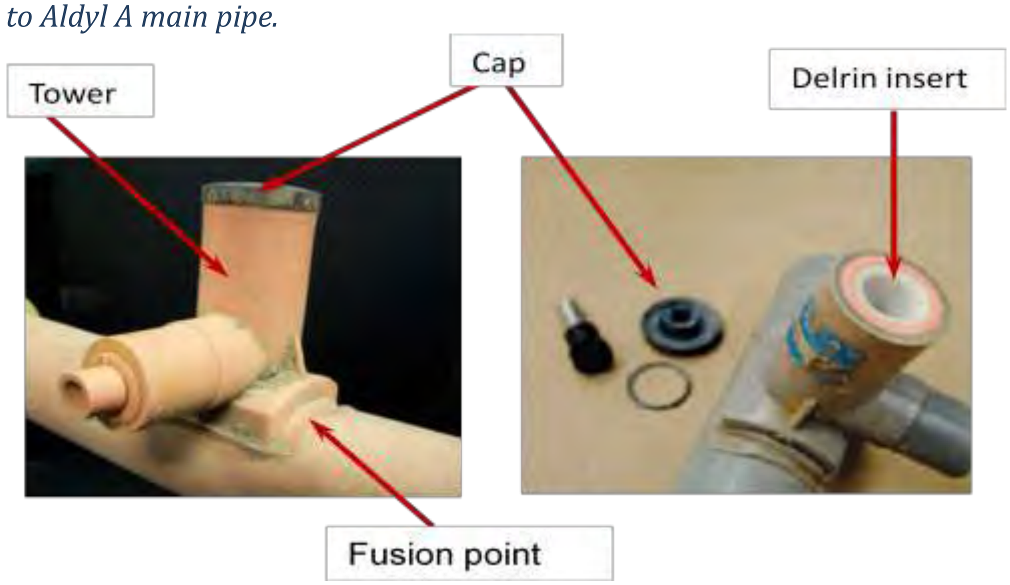
Figure 1. Modes or types of material failures documented in a sample of 113 leaks in Avista's Aldyl A piping in Washington State, December 2005 through March 2011.



Towers and Caps

The largest percentage of material failures in the sample occurred in Towers and Caps, referring to failure of the service tapping tee itself, shown below in Figure 2. In these cases, the pressure applied to the tee as the cap was tightened onto the body during initial installation has resulted in slow crack growth and failure of the tower body, the cap, or the Delrin® insert many years later. Additionally, the saddle fusion point of the tower to the main pipe is another frequent point of failure in this assembly. The unavoidable stresses created during standard installation (using factory recommended procedures) have led to brittle cracking in these components many years later. This phenomenon clearly demonstrates the susceptibility of certain resins of Aldyl A piping to tend to fail by brittle cracking due to the slow crack growth initiated during installation.

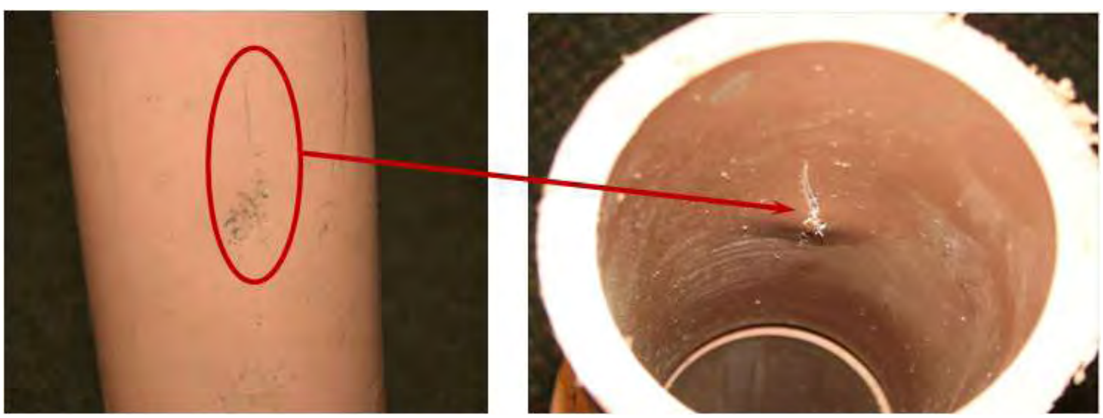
Figure 2. External features and internal components of a typical Aldyl A service tee, as fused to Aldyl A main pipe.



Rock Contact and Squeeze-Off

The second-most common material failure observed in Avista's Aldyl A pipe was due to localized, brittle cracking in Aldyl A mains that resulted from rock impingement – rock pressure directly on the pipe, or places where 'squeeze-off' was applied over the pipe's service life. These failures are very typical for certain resins of Aldyl A main pipe, having been consistently reported by other utilities since before the time of DuPont's 1986 letter. As described earlier, when these external stresses (rock impingement or squeeze-off) cause the pipe to fail, it always begins with crack initiation on the inside surface of the pipe wall, eventually resulting in slow crack growth that propagates toward the outer wall of the pipe, and finally, through-wall failure. These failures generally appear as short, tight cracks in the outer wall of the pipe that run either parallel, or slightly off-parallel with the length of the pipe. A typical failure in Aldyl A main pipe, showing a crack through the pipe wall as it appears on both the inner and outer surfaces, is shown below in Figure 3.

Figure 3. Typical brittle-like crack through the wall of Aldyl A pipe, resulting from rock contact directly on the pipe.



Although the duration of the stress caused by rock contact with the pipe is very different from that associated with squeeze-off, they both result in the same pattern of crack initiation and slow crack growth leading to failure of the pipe. Other sources of external stress that can result in brittle failure of Aldyl A pipe, as mentioned earlier in the report, include bending of the pipe, soil settlement, dents or gouges to the pipe, and improper installation of fittings.

Services Tapped from Steel Mains

The third most-common failure in Avista's sample occurred where small diameter Aldyl A service pipe is tapped from steel main pipe. In this application, a steel service tee is welded to the steel main pipe and the small-diameter Aldyl A service pipe is then connected to a mechanical transition fitting on the tee, as pictured below in Figure 4.

Figure 4. Typical polyethylene service tapped from a steel main.

It is at this transition point, between the rigid steel fitting and the more-flexible Aldyl A service pipe, that brittle-like cracking has been observed. This failure mode in older plastic pipe is well understood, and was one of the three study objectives reported by the National Transportation Safety Board in its 1998 bulletin, summarized earlier in this report.

Avista's Aldyl A Services

Avista believes its Aldyl A "service" piping, apart from cracking at the connection with the tee on steel main pipe, has no greater tendency to fail than its other polyethylene service piping, and at this point in time, should not be managed differently than other plastic service pipe (frequency of leak survey, etc.). Consequently, Avista is not planning to systematically replace Aldyl A service pipe as it replaces main pipe and rehabilitates service connections at steel tees. Avista is using the Integrity Management model, however, to track and analyze service leaks going forward to determine if the reliability of Aldyl A service piping changes in ways that warrant a different approach.

Understanding the Significance of Leaks in Aldyl A Pipe

Frequency and Potential Consequence

Analysis of the material failures of Aldyl A pipe provides the opportunity to put these leaks into perspective with other types of leaks on Avista's natural gas system. As part of the development of the Integrity Management Plan, five years of leak data were analyzed for Avista's three-state service territory. The data included nearly 17,000 individual leaks, which were categorized according to the underlying threats to the natural gas system as required under Integrity Management. As a point of comparison of the significance of leak types, the data included in excess of 2,000 leaks associated with the failure of gas system equipment, such as valves, fittings and meters. Only 153 leaks, however, were identified as resulting from 'material failures' of Aldyl A piping in the three states. Looking simply at Aldyl A leaks as part of the aggregate of all system leaks, one might conclude that Aldyl A pipe failures pose a limited potential for hazard relative to the threat of other system leaks. In fact, while gas equipment leaks are more likely to occur, their potential consequence is often minimal. A thorough understanding of this difference is one of the most important requirements and outcomes of any effective Integrity Management Plan analysis.

Review of the leak-history data shows the vast majority of equipment leaks as occurring typically with shut-off valves and gas meters, located either above ground or in locations that allow free-venting of gas to the atmosphere. Consequently, these types of leaks have a low potential to result in an incident posing harm. Through public awareness programs, people have become familiar with the odor of venting gas and tend to quickly call Avista to make repairs; this is especially true if the venting gas can be associated with visible gas valves or meters. By contrast, Aldyl A failures and the associated leaks occur almost entirely underground, out of sight, often in populated areas, and occasionally in the proximity of buildings that are not actually connected to the natural gas system. Without visible facilities, natural gas may have an unexpected presence in the environment that allows people to dismiss slight gas odors. This reduced awareness allows gas from these undetected leaks to have the significant potential to migrate into buildings before it can be identified and reported. This is especially true in winter when the ground is saturated, frozen or snow covered, and in areas of full pavement and concrete finishes. Of the roughly 2,000 equipment leaks reported in the five years of data reviewed, none resulted in gas incidents. By comparison, two of the relatively-small number of Aldyl A material failures resulted in gas migrating into buildings undetected, and upon accidental ignition, resulted in harmful incidents.

The Complication of Brittle Cracking in Aldyl A Pipe

The common mode of failure for Aldyl A materials, brittle-like cracking, can also present special problems compared with leaks in other gas piping, such as corrosion in steel gas pipe. Corrosion leaks tend to begin with the failure of a very minute area in the pipe wall, which then begins to release a very minute amount of natural gas. These leaks then tend to progress very slowly and in a stable and somewhat predicable way over time. These types of leaks, while never positive, are more likely to be detected by modern gas-detection equipment when they are at a stage where the release of gas is relatively minor. By contrast, leaks in Aldyl A piping tend to first appear as substantial (high gas volume) leaks that appear in a very short time period. This is due to the nature of brittle cracking, where the crack can progress very slowly from the inner wall of the pipe toward the outer wall without any release of gas, until the pipe finally splits open, resulting in a substantial failure. Additionally, unlike the prevention or even suspension of corrosion problems in steel pipe through effective protection methods, there is no way to halt undetected progress of slow crack growth in brittle Aldyl A pipe.

VIII. Reliability Modeling of Avista's Aldyl A Piping

Avista's Asset Management Group performed reliability modeling for several classes of its natural gas pipe in order to assess the long-term performance of its Aldyl A piping, compared with steel pipe and newer-vintage plastic pipe. Reliability analysis comes from the discipline of 'reliability engineering' and is a foundational asset management tool that provides a forecast or prediction of the future performance of a piece of equipment (pipe, in this instance). The predicted asset performance then provides the basis for the application of other asset management tools, allowing the development of the ultimate maintenance or replacement strategies that optimize asset cost with any number of other factors, such as availability for service or risk avoidance.

Availability Workbench Software

Avista developed reliability forecasts for its Aldyl A and other piping using Availability Workbench™ software. This 'off the shelf software' was introduced by Isograph, Ltd., the world's leader in reliability analysis software. Availability Workbench was first introduced in 1988, and is used to support asset decision making in over 7,000 sites around the world and across a range of industries, including Aerospace, Automotive, Chemical, Defense, Electronics, Manufacturing, Mining, Oil and Gas, Power Generation, Railways, and Utilities. Avista's version of the model was released in 2009.

Reliability Forecasting

Availability Workbench has four modules, one of which, the Weibull module, is used to create reliability forecasts (curves) for an asset. Reliability curves for gas piping are generated from input data that include pipe inventory (type, brand, footage, location, soil conditions, etc.), current age of piping, historic and current failure information and repair data. Avista uses predominantly its own historical data for these inputs, but when they must be estimated, they are vetted by subject matter experts within the company. The model integrates pipe age and failure and repair data, and then by applying a conventional Weibull-curve mathematical model, it produces probability curves that represent the expected failure rates over time for each failure mode, such as the brittle-like cracking associated with Aldyl A services tapped to steel mains. The reliability curves represent how quickly the rest of the pipe is at risk of failing, shown as the percentage of failures expected each year over time.

Forecasting the Reliability of Aldyl A Piping

The objective of Avista's reliability modeling was to forecast expected failures for elements of Avista's Aldyl A piping system, compared with that of steel and latest-generation polyethylene pipe. The observed Aldyl A failure modes, discussed above, including leak data for other types of gas pipe in Avista's system, provided high-quality leak and age information for the reliability modeling. Forecasting was performed for the following pipe 'classes' in Avista's system.

a. Aldyl A Main pipe of Pre-1984 manufacture (Alathon 5040 and 5043 resins, including low ductile inner wall pipe)
b. Aldyl A Main pipe manufactured during 1984 and after (Alathon 5046-C and 5046-U resins)
c. Aldyl A Services Tapped to Steel Main (Bending Stress Services)
d. Steel pipe
e. Newer Polyethylene pipe (1990 and later)

To perform the modeling, the data for these pipe classes must be input as discrete elements, which are described as follows:

Main Pipe - Analyzed using 50-foot segments as discrete modeling elements.

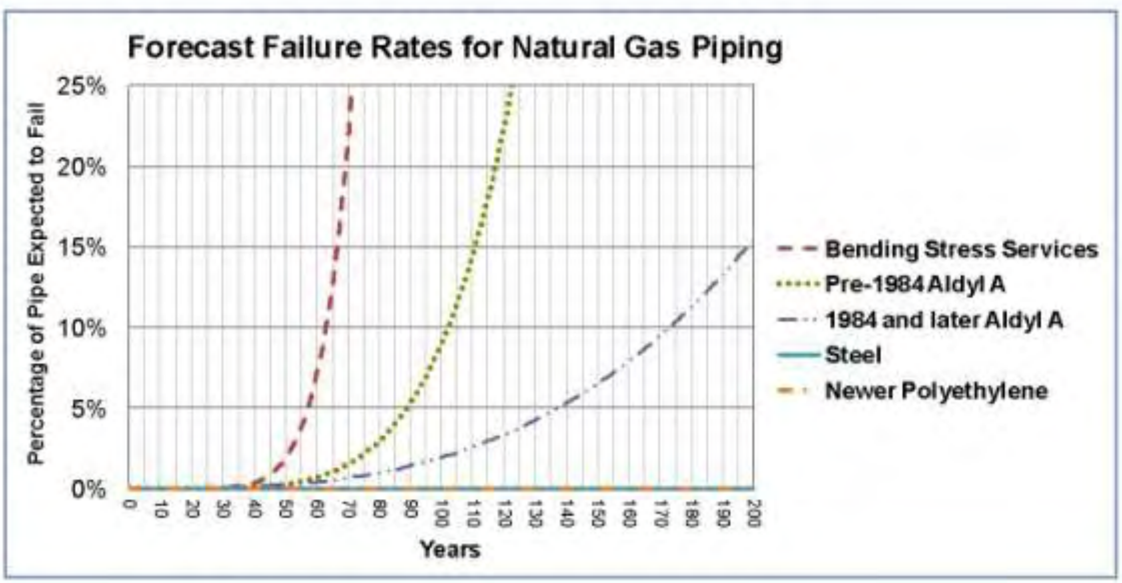
Services Tapped from Steel Mains - Avista identified 16,000 such services in its system, also referred to as 'bending stress tees.' For the reliability modeling, the individual service is the discrete element.

Forecasting Results

Forecast Piping Failures

Results of the forecast modeling, for the pipe classes evaluated, are represented as 'curves' showing the percentage of the amount of each pipe class that is projected to fail in each year of the forecast time period. The resulting reliability curves are shown in the graph below in Figure 5.

Figure 5. The expected failure rates for several classes of pipe in Avista's system, as forecast by Availability Workbench Modeling. The "Steel" curve is obscured by the "Newer Polyethylene" curve, both of which are essentially flat lines.



The failure curves show dramatic differences in the expected life for the pipe classes evaluated. The difference in expected life between the Aldyl A products as a group, compared with that of steel and newer-generation plastic pipe, is particularly evident. Striking also, are the expected performance differences among the classes of Aldyl A pipe evaluated, providing some clear trends useful in designing remediation strategies.

Dependability of Forecasting Future Failures

The reliability forecast is essentially a mathematical calculation of the ‘chance’ of future failure and decisions of significant risk and financial magnitude are based, at least in part, on that result. Importantly though, the forecast has a ‘real numbers’ foundation in the actual leak data, records of material failure and repair, and the relationship of those events with time. For Aldyl A pipe, the model is using observed endpoints in the life of the pipe resulting from a loss in ductility and slow crack growth, for example, and integrating that with other data to forecast future expected failures. Comparatively, the relatively rare observed failures in steel pipe and newer-generation plastic pipe are reflected in their nearly-flat cumulative failure curves. The value of using proven reliability forecasting approaches and widely-adopted software is derived from their ubiquitous application across reliability-critical industries, and their continuous testing, evaluation, and support. Finally, as Avista adds new data in coming years for pipe failures of all material classes, including Aldyl A, it serves to increase the statistical power of the forecast results.

Understanding the Significance of Cumulative Failure Curves

Although the failure curves for the different classes of pipe differ significantly over the long term, as mentioned, the failure rates also appear to remain below one percent for the first 45 years for Aldyl A services tapped to steel main, and for 65 years for Pre-1984 Aldyl A main pipe. Since the weighted average age for Aldyl A pipe in Avista’s system is 32 years, it would appear that we might have ample time before the failure rate would start to rise substantially for Pre-1984 Aldyl A main pipe. Using the Pre-1984 main pipe in Washington as an example, the failure curve estimates that when this pipe is 65 years old that approximately one percent of it will fail in that single year. Given that Avista has 328 miles of this vintage pipe in Washington, that mileage equals nearly 35,000 discrete elements (50-ft sections) in the forecast model. The one percent failure, then, translates to 346 leaks in that 65th year. To put this failure rate into perspective, consider the 113 leaks documented (primarily on Pre-1984 main pipe) over the past five years in Washington state. The 113 leaks equal an average of 22.6 leaks per year, or an annual failure rate of 0.06 percent. Since it is expected that the number of hazardous leaks and incidents would increase proportionally with the increase in total leaks, then it’s easy to imagine just how unacceptable the pipe performance would be at an annual failure rate of one percent.

Prudent Management of Anticipated Failures

To carry this point further, if we “zoom-in” on the curves we can gauge the significance of the change in failure rate that is expected ten years from today. At that point the weighted average age of Aldyl A pipe in Avista’s system will be 42 years, and the expected failure rate for Pre-1984 Aldyl A main pipe in that year will be just over one-tenth of one percent (0.12%), or 42 leaks in that year. This failure rate, while still just a tiny fraction of the one percent rate used in the example above, represents almost a doubling of the average annual rate for the past five years (22.6), a time when two of the documented leaks resulted in injury and property incidents and dozens more were categorized as hazardous leaks[3], timely repaired. The critical point in this example is the understanding that failures in buried natural gas piping can be prudently managed only when they are occurring at very low rates. Otherwise new leaks in the system occur too frequently to be detected by even annual leak surveys of the entire system, resulting in an increase in the likelihood of hazardous leaks and the potential for harmful incidents.

Priority Aldyl A Piping

Every pipeline operator strives to install and maintain a safe, reliable and cost-effective system. While the goal is complete system integrity, it is impossible to avoid having any leaks, especially on large systems such as Avista's with over 12,000 miles of mains and several hundred thousand services. Regulators and the industry acknowledge this reality through the adoption of standardized leak-survey methodologies, and recognized pipe remediation practices.

While leaks are inherent on a system, there are circumstances where the expected failure rate of a particular pipe begins to rise compared with that of other piping and industry norms. We have demonstrated that such is the case for portions of the Aldyl A pipe in Avista's system, and accordingly, we have determined these classes to be at-risk of quickly approaching a level of reliability that is unacceptable and in need of proactive remediation. It's for this reason that Avista refers to these pipe classes as "Priority Aldyl A piping."

IX. Formulation of a Management Program for Priority Aldyl A Pipe

The timely application of Avista's Integrity Management approach to its recent and ongoing leak analysis and its reliability modeling results, including Dr. Palermo's review, and the experience gained in three priority pipe-replacement projects in 2011, has prompted Avista to formulate a protocol for systematically managing its Aldyl A pipe. The following categories are useful classifications for Avista's definition of "priority Aldyl A pipe"[4]:

1. Aldyl A gas services tapped to steel main pipe
2. Pre-1973 Aldyl A main pipe
3. Pre-1984 Aldyl A main pipe

Avista has determined these classes of pipe are at risk of approaching unacceptable levels of reliability without prompt attention. Accordingly, Avista believes the decision to formulate a management program for its priority Aldyl A pipe is both timely and prudent,

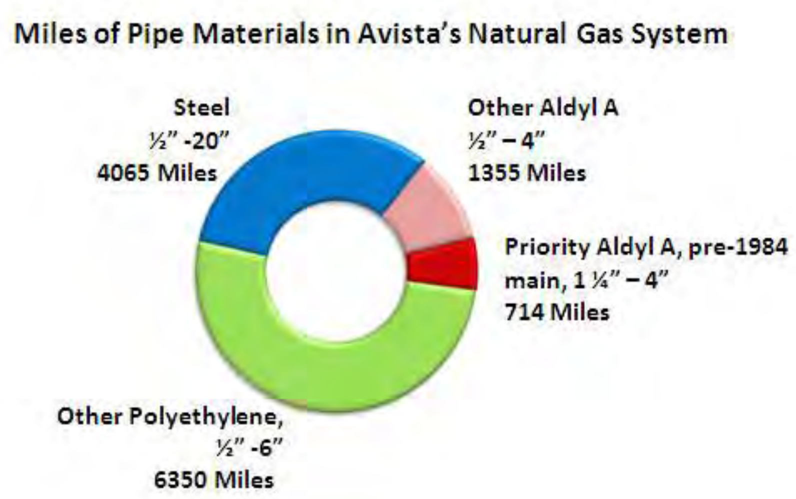
[3] The Pipeline and Hazardous Materials Safety Administration defines a "hazardous leak" as an unintentional release of gas that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.
[4] Each class noted above is subject to material failures due to concentrated stresses such as rock impingement, bending stresses, squeeze off, and failures of service towers and caps.

and is consistent with results of our leak investigations, Integrity Management principles and the recent Call to Action of Secretary LaHood. The decision is also consistent with the prior federal bulletins on this subject and with the decisions of other similarly-situated utilities that have implemented similar pipe-replacement programs. Finally, given the significant amounts of priority Aldyl A pipe on Avista's system, commencing a protocol now provides us greater opportunity to manage these facilities in a prudent and cost-effective manner.

Priority Aldyl A Piping in Avista's System

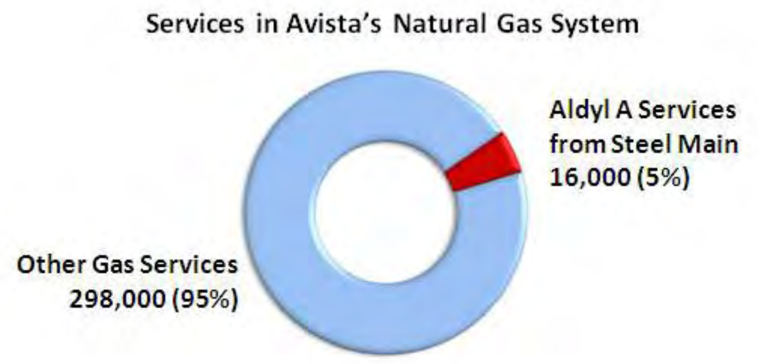
Main Pipe - Avista has approximately 12,500 miles of natural gas main pipe in its service territories in the States of Washington, Oregon and Idaho. Approximately seventeen percent of this total, or 2,000 miles, is Aldyl A pipe of all classes and sizes. Proportions of various classes of piping in Avista's system, including priority Aldyl A pipe (pre-1973 and pre-1984 mains) is shown below in Figure 6.

Figure 6. Avista's priority Aldyl A pipe, shown as a proportion of the different pipe classes in Avista's natural gas system (items 2 and 3 from the list above).



Gas Services - Avista has approximately 314,000 natural gas services, of which approximately 16,000, or five percent, are Aldyl service pipe tapped to steel main pipe, shown below in Figure 7 as priority Aldyl A services.

Figure 7. Avista's priority Aldyl A gas services (tapped from steel mains), shown as a proportion of Avista's total gas services.



X. Other Aldyl A Pipe Replacement Programs

Aldyl A Pipe in the Pacific Northwest

Through general conversation with our colleagues in western gas utilities, Avista believes it has a substantially greater proportion of Aldyl A pipe in its system than do our neighboring Pacific Northwest gas utilities. The proportions of Aldyl A in Avista's system (or of any other brand of early polyethylene pipe), however, is not a reflection of the unique purchasing practices of Avista, since plastic pipe quickly became the standard of the industry and the predominant pipe installed by utilities across the county. However, the proportions of early plastic pipe in a system do tend to track with the amount of system growth that gas utilities experienced during the 1970s and early 1980s. For Avista, this was a time of particularly rapid expansion of its natural gas system (from the Spokane metro area to outlying communities in its Washington and Idaho service territories), and consequently, the proportion of early Aldyl A pipe in our system reflects this period of expansion.

Established and Emerging Programs for Aldyl A Pipe Replacement

Two western utilities, Southwest Gas and Pacific Gas & Electric, have significant Aldyl A pipe management programs either well underway or anticipated, which are very briefly summarized below.

Southwest Gas – Responding to a fatality incident in the early 1990s, Southwest Gas entered into a settlement agreement with the Corporation Commission of Arizona to conduct additional leak monitoring and pipeline remediation (See Attachment 9). By the late 1990s, Southwest Gas had replaced 74 miles of Aldyl HD (high density) main pipe covered by the agreement, and had replaced another 648 miles of Aldyl A pipe based on its leak survey monitoring results. In 2005, Southwest Gas had another injury and property incident on their system involving Aldyl A pipe, and implemented an additional pipe replacement program in the vicinity of the incident. Southwest Gas has also worked closely with staff of the Public Utilities Commission of Nevada in the monitoring and replacement of what the Commission refers to as "aging" and "high risk" natural gas pipe, including Aldyl A pipe (See Attachment 10).

Pacific Gas & Electric - After some very high-profile natural gas incidents in 2011 that involved Aldyl A piping, Pacific Gas & Electric has announced plans to replace all the Pre-1973 Aldyl A pipe in its system (See Attachment 11). The utility reportedly has 7,907 miles of Aldyl A pipe of all classes in its system, which is about 19 percent of its gas system inventory. By comparison, Avista's Aldyl A pipe stock is about 16 percent of its system. Pacific Gas & Electric's planned replacement of its Pre-1973 Aldyl A pipe represents a massive effort because the utility plans to remove and replace the 1,231 miles of pipe in a proposed timeframe reported as in the range of three years, and at a cost said to exceed $1 billion, but that has not yet been formalized. There is some question regarding the selection of only pre-1973 Aldyl A for replacement in PG&E's system, since at least one recent high-profile incident was reported on newer vintage (still pre-1984) Aldyl A.

Developments of Interest

US Congresswoman Jackie Speier of California has been raising the awareness of Congress and Transportation Secretary, LaHood, in two separate actions. First, in May 2011, Speier sponsored House Resolution 22 entitled the "Pipeline Safety and Community Empowerment Act of 2011." The legislation provided for citizens being able to easily access pipeline maps and safety-related information from pipeline owners, prescribed certain changes in pipeline monitoring requirements, and called for the addition of physical safety devices to existing pipelines. The bill is currently under consideration by the House Committees on Transportation and Infrastructure, and Energy and Commerce.

In October 2011, Speier wrote to Secretary LaHood calling on him to direct the Pipeline and Hazardous Materials Safety Administration to "take immediate action to address the long-known safety risks associated with pre-1973 Aldyl-A plastic pipe manufactured by DuPont." She went on to advocate for the removal of this pipe from use in the U.S., and to commend Pacific Gas & Electric for its planned removal of all of its pre-1973 Aldyl A pipe. Citing the DuPont letters to customers, federal safety bulletins, and the Waterloo incident, she chided Congress for not taking action, and urged the Secretary to immediately do so (See Attachment 12).

XI. Designing Avista's Replacement Protocol for its Priority Aldyl A Pipe

Avista modeled two different approaches to the replacement program, one that was systematic, based on an established timeframe and one that was responsive to problem areas as they were identified.

Systematic Replacement Program

Time Horizon

Determining the appropriate length of time over which to replace the Priority Aldyl A pipe involves the optimization of several factors, including: 1) the overall urgency from a reliability and safety perspective, both present and forecast; 2) potential consequences; 3) the impact of more intensive leak survey methods to better identify priority facilities in need of replacement and in helping reduce the potential for harmful incidents; 4) the ability to effectively prioritize specific projects to better ensure facilities in greatest need are addressed earliest; 5) the availability of equipment and labor resources needed to conduct the work, and the ability to coordinate the work with Avista's ongoing construction programs; 6) program efficiency, and 7) the degree of rate pressure placed on customers, both in absolute terms and in relation to other reliability and safety investments required across the natural gas and electric business. Ultimately, Avista must ensure that management and removal of its Aldyl A pipe is conducted in a way that shields our customers from imprudent risk, while at the same protecting them from the burden of unnecessary costs.

Prudent Management of Potential Risk

Avista believes it is important to establish for our customers and other stakeholders that while there can never be 'zero risk' associated with the program, the potential risk can be prudently managed. On one hand, a replacement program carried out over a very short timeframe cannot prevent the occurrence of all leaks forecast to occur over the course of the program. But at the other extreme, it's clear that setting a replacement timeline that's too lengthy would likely result in safety, reliability and financial consequences for our customers and our business that could be regarded as unacceptable. Avista believes the timeline for the replacement program should optimize the factors mentioned above in a way that reduces the risk associated with Aldyl A pipe to the range of 'prudent risks' associated with the myriad other electric and gas facilities and practices that are used to serve the energy needs of utility customers. Avista's treatment of its Aldyl A pipe will be managed to comport with these sound business practices.

Prioritizing the Work

As important as the replacement timeline in prudently managing the reliability of Avista's Aldyl A piping, is the ability of the Asset Management and Distribution Integrity Management staff to partner in effectively prioritizing the pipe-replacement activities in a way that minimizes the potential for hazardous leaks. Results of the Availability Workbench modeling provide some support in prioritization but do not take into account factors such as soil conditions or the proximity to buildings or people. Obviously, a leak occurring in a vacant field will have little, if any, consequence and will likely be detected and repaired during the next leak survey. By contrast, the potential hazard of a leak increases with its proximity to people and structures, so replacing pipe that has a high probability of leaking and is located in populated areas is first priority.

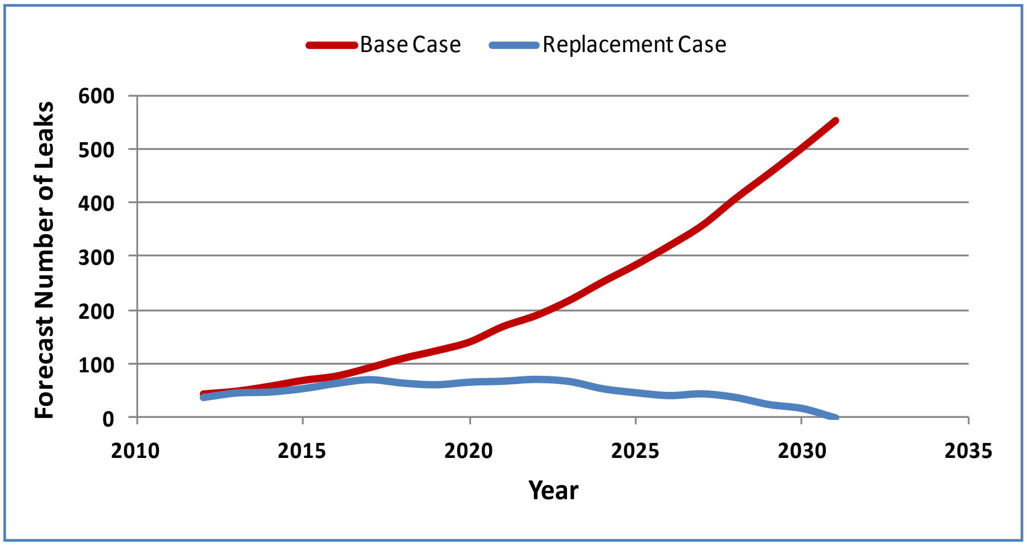
Avista's Integrity Management approach provides the analytical tools that integrate key knowledge and information needed to effectively prioritize replacement activities based on the potential hazard. In the prioritization process, each segment of Aldyl A pipe in Avista's system is assigned a relative risk ranking, based on its age, material, soil conditions, construction methods, and its maintenance history. This information is then loaded into Avista's GIS database containing the gas system maps. These maps contain a "layer" of grid squares (50 feet per side) that correspond with sections of the Aldyl A pipe. Each square is known as a "raster" and each raster contains all of the risk-related information that was loaded into the GIS system, as associated with the Aldyl A pipe at that precise geographic location.

Next, the software integrates the historic leak information for Aldyl A pipe on Avista's system with the risk data associated with each of the Aldyl A pipe segments, and predicts the geographic areas (via the risk rasters) where Aldyl A pipe failures are expected to be greatest. In the last step, the software integrates the results for expected failures with information for each risk raster that identifies the potential consequence of a leak on that segment (i.e. the proximity of that raster to buildings and people, and the population density/sensitivity of those structures). The end result is a color-coding of the rasters that provides a visual picture of where on the gas system that both the potential likelihood of a leak, and the potential consequence of a leak, are greatest. This approach provides Avista with a comprehensive and objective means of identifying Aldyl A pipe that has the highest priority for replacement.

Twenty-Year Proposal

Avista modeled various time horizons for the replacement program, up to a timeline of 30 years, and determined a replacement horizon in the range of twenty years to represent an optimum timeframe for removing and replacing its priority Aldyl A pipe. Shortening the timeline was found to have increasing cost impacts to customers but with little improvement in the numbers of expected facility failures. Lengthening the timeline past twenty years, however, was found to result in a substantial increase in the number of material failures expected. A replacement timeline of 25 years, for example, resulted in more than a doubling of the number of leaks expected when compared with the twenty year horizon. Under the twenty year replacement program, the number of material failures each year is expected to increase slightly until 2017, at which time the cumulative effect of priority piping replaced since 2012 begins to check the failure count and then drive it toward zero over the remaining course of the program (Figure 8).

Figure 8. Expected numbers of material failures in Avista's priority Aldyl A piping in two cases: Replacement Case - piping replaced over a twenty year horizon in the manner proposed by Avista in this report, and Base Case – assumed that priority piping was not remediated under any program.



Importantly, Avista is not suggesting that experiencing an increase in leaks on our system is "acceptable" per se, in particular, after having had two harmful incidents in the past few years. What we are saying, however, is that by using the Integrity Management model to prioritize work activities in the manner described above, Avista believes it can manage the forecast Aldyl A leaks in a way that significantly reduces their potential occurrence in areas that could result in harm. Under this approach, Avista believes it can prudently manage the replacement of priority Aldyl A pipe with the goal to avoid harmful incidents, and at a reasonable rate impact for our customers.

Initial Optimization

Importantly, Avista's proposal for a 20-year replacement program represents an optimization based on the information we have available today. Any number of factors could change as the work proceeds over the first few years that could result in a 'new' optimum time horizon. Avista will be collecting new leak survey and other information each year, and will continue to use its Asset Management models to further refine expected trends and potential consequences, making program adjustments as appropriate.

Responsive Replacement Program

Avista also modeled a very-different pipe replacement strategy to provide a further measure of the efficacy of the systematic replacement program. This scenario, referred to as the Responsive Case, was essentially a reactive approach where pipe remediation and replacement activities would be driven by leak survey results and the magnitude of leak consequences. Under this case, it's expected that pipe replacement activity would commence at a lower level than in the systematic case, but would also vary significantly from year to year, depending on patterns of detected leaks and their consequences. Ultimately, however, the expected activity and spending levels would far exceed both the annual and cumulative costs of the systematic approach. This is because pipe segments are not replaced ahead of actual material failure (as happens in the structured case) and so the resulting work activity more generally follows the geometrically-increasing numbers of material failures expected over time. This scenario was easily judged as failing to provide an appropriate measure of prudence, including system safety, reliability, cost-efficiency, or business risk. Without a prioritized replacement protocol in place, Avista would be resigned to replacing pipe in response to serious leaks and potential incidents, after-the-fact, rather than with foresight.

From a practical standpoint, Avista believes that by managing the replacement of its priority Aldyl A pipe in a systematic way it can prudently manage potential risks and impacts to its customers and other stakeholders, plan for and use construction resources most efficiently, and plan more effectively for the capital and expense requirements necessary for the effort. This is clearly the case when compared with a responsive approach.

Dr. Palermo's Assessment of the Proposed Protocol for Managing Avista's Priority Aldyl A Piping

Following Avista's Integrity Management evaluations of failure trends in its Aldyl A piping, and the development of its proposed protocol, we invited Dr. Palermo to review the completed protocol and to judge, from his expert perspective, the overall effectiveness and adequacy of the program. Dr. Palermo completed his review in February 2012, and judged Avista's protocol to be highly responsive and appropriate to the management needs of the priority Aldyl A pipe in Avista's system. In particular, he noted his support for Avista's priority focus on pre-1973 Aldyl A pipe, and on the plan to remove and replace its pre-1984 Aldyl A mains. He further noted his agreement with Avista's priority for remediating Aldyl A services tapped to steel main pipe, and to the protocol of "managing in place" existing Aldyl A service piping between the mains and meters. Finally, Dr. Palermo agreed with the proposed twenty-year replacement time horizon for Avista's priority Aldyl A pipe, noting the reliability modeling results, and the effectiveness of Avista's increased leak survey and application of Integrity Management information, tools and analysis in prioritizing pipe replacement activities. Dr. Palermo reviewed and approved this affirmation prior to the finalization of this report.

XII. Application of Avista's Washington State Study Results to Aldyl A Pipe in the States of Oregon and Idaho

Forty-six percent of Avista's Aldyl A main pipe is currently in service in the State of Washington, and coincidentally, so are 46% of Avista's Aldyl A services tapped to steel mains. Since Avista's leak survey study and subsequent modeling results are based on Washington State data, then it follows that the expected results are most applicable to this jurisdiction. The degree to which the reliability modeling results are applicable to Avista's Aldyl A pipe in the States of Oregon and Idaho depend on factors such as the age of the at-risk pipe and on the known similarity of conditions under which the pipe was installed, including method (trenching or plowing), backfill material, compaction and squeeze-off practices, soil conditions and ambient soil temperature, etc. Avista is aware of at least some general differences among state jurisdictions, including more favorable soil conditions in Oregon, newer pipe materials, and construction techniques potentially more favorable to low-ductility pipe. A contributing complication, too, is the relatively large amount of pipe of unknown age and material in service in Oregon. This territory was acquired by Avista from a utility that did not have a consistent practice of mapping services, and some existing maps were lost before the purchase. As a result, Avista is conservatively managing this pipe as if it was priority Aldyl A pipe, until the time that these segments are verified by records review and possible field verification.

Most important to this discussion, however, is the fact that Avista is using its Integrity Management model to integrate leak survey and other data to develop the priority pipe replacement activities for each year of the program. Since comparable leak survey data from priority Aldyl A pipe in Idaho and Oregon will be included in the prioritization analysis, then regardless of any differences that do affect the expected reliability of the Aldyl A pipe, that inherent reliability will be automatically integrated into the modeling, ensuring that Avista is systematically replacing the pipe at greatest risk, regardless of the jurisdiction. Finally, since the Medford and Grants Pass, Oregon, service territory offers a 12-month construction season, Avista will be able to continuously mitigate priority Aldyl A piping within that area when northern territories are effectively unable to continue working.

XIII. Resource Requirements and Expected Cost

Staffing

Avista's proposed Aldyl A pipe replacement project represents a major undertaking, even when spread over a twenty-year horizon. In addition to the scope of the effort, there's added complexity in efficiently managing the project, since Avista's territory extends from Bonners Ferry, Idaho to Ashland, Oregon, a distance of over 650 miles. Each year, the deployment of equipment and inspection and construction personnel will have to be adjusted across this service area in response to the sites identified for highest-priority pipe replacement in any given year. Avista is planning to coordinate with contractors to manage much of this construction, and since this project represents a long-term construction commitment, it is expected that the pool of contractors bidding for this work will be substantial, resulting in advantageous pricing and flexibility of field labor.

Though much of the physical construction will be accomplished through the use of contractors, there will still be a need to increase Avista's internal staffing to manage the flow of information, quality assurance, mapping, and related project documentation. Quality assurance is a critical project element that Avista will rigorously control. Effective remediation of Avista's priority Aldyl A pipe is a critically-important corporate objective, and we must continually ensure that sound inspection, training and auditing delivers the results we expect. Finally, the pipe replacement activities themselves will often have disruptive effects on our customers and others. Avista will carefully coordinate customer and community communications and notifications in an effort to minimize the effects of any disruptions.

Capital Costs

Avista's analysis and planning effort is projecting capital costs just over $10 million annually from the year 2013 – 2032. Actual costs will vary somewhat depending on the prioritization of piping to be replaced each year, among other factors, and the calculated amounts will also be subject to annual inflation. Avista is planning to spend approximately $5 million in capital on this program in 2012, and $8 million in 2013, allowing for effective planning with contractors, hiring Avista staff, and developing a solid project management foundation for years 2013 and beyond.

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 1

1982 DuPont Letter

1982 DuPont Letter

Z-189 REV. 4/81

DU PONT
REG. US PAT & TM OFF
ESTABLISHED 1802

E. I. DU PONT DE NEMOURS & COMPANY
INCORPORATED
WILMINGTON, DELAWARE 19898

POLYMER PRODUCTS DEPARTMENT

December 17, 1982

It has now been over 18 years since Du Pont developed and introduced the first complete polyethylene piping system designed specifically to meet the needs of the gas distribution industry. Over this period of time, the use of Du Pont's Aldyl® "A" piping system and other polyethylene systems has increased to the point that 84% of the gas distribution pipe installed in 1981 was polyethylene. The outstanding overall performance of the polyethylene pipe installed since 1964 is the primary reason that polyethylene pipe has become the standard for the industry. We believe that the value of polyethylene piping systems has been well documented.

As a responsible long-term supplier committed to the gas industry, we have had a continuing research program aimed at defining the ultimate service life and failure modes of polyethylene pipe in gas distribution service. This program has been and is being supplemented by information received from gas utilities on their experience with Aldyl® "A" pipe.

In metal pipe, corrosion has been the ultimate failure mechanism that has determined when pipe should be replaced. So far, nearly all failures reported in polyethylene piping systems have been caused by either third-party damage or improper fusion practices during installation. These problems can and generally have been minimized by more extensive education and training programs. Although these causes may continue to be the primary reasons for leaks, we believe that every utility with polyethylene piping systems should maintain well-defined leak analysis procedures. Documentation and analysis of individual leak occurrences should help to define the ultimate failure mechanisms, the expected useful life, and appropriate repair or replacement programs.

As in the past, we will continue to assist our customers in planning details of their leak analysis programs including record-keeping, test methods, etc. As an example of the new information such programs can provide, two of our customers have reported instances* of leaks due to slits in Aldyl® "A" pipe made before 1973. The slits have only occurred in 1-1/4" and larger sized pipe. Nearly all of the slits were in pipe installed in point contact with rocks. This low frequency of leaks due to slits has not been reported for pipe made after 1972. Our records indicate that a process improvement was made in late 1971 and early 1972 as part of our continuing effort to utilize our most up-to-date technology. We believe, therefore, that Aldyl® "A" pipe made since that time is more resistant to the formation of slits from point contact with rocks. However, as with coated steel pipe, polyethylene pipe should be installed using established methods which avoid point loading with rocks.

After finding these leaks, the two utilities have increased the frequency of their leak detection surveys for pipe installed before 1973, particularly in those subdivisions where other leaks suggest that rocks may have been included as part of the backfill. We believe that all utilities with Aldyl® "A" pipe installed prior to 1973 should consider more frequent leak detection surveys. The attached sheet shows the purchases by year for your company prior to 1973.

In the future, as we learn of other significant field performance data on our product or develop our own laboratory data, we will share this information with you. High quality polyethylene systems have become an important part of the gas distribution business in providing good performance and safety at minimum costs for installation and repair. It is important as the amount of pipe grows and service times increase, that the management of system maintenance proceeds on a rational, planned basis. We hope the ideas and information included here are helpful toward that end. We look forward to your comments and questions.

Sincerely,

Don F. Zerbe

Don F. Zerbe, Jr.
Marketing Manager
Aldyl® Piping Systems

DFZ:dmst
Attachment

* Averaging less than 1% of all field repairs.

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 2

1986 DuPont Letter

1986 DuPont Letter

11/04/2003 17:16 FAX 9184469369 UPONOR ALDYL CO 002

C 777 7

DU PONT ALDYL® PIPING SYSTEMS

QUALITY • INNOVATION • SERVICE

E. I. DU PONT DE NEMOURS & COMPANY (INC.) WILMINGTON, DELAWARE 19898
ALDYL® Piping Systems

August 25, 1986

Dear Customer:

Over twenty years have passed since the first full Aldyl® "A" Polyethylene Piping System was installed in gas distribution service. During those decades both the gas industry and system suppliers have gained experience. As a result, today's systems incorporate improved resins and protective additives, system components are readily available, tooling and installation techniques have been improved, and testing methods have been developed to define design strength and estimate long-term system performance.

Consistent with our position as a reliable and responsible supplier to the gas distribution industry, Du Pont has continued to conduct research programs aimed at new product development and better understanding of existing product performance. We have, over the past years, shared the results of this research effort with you, our customers.

One of the major technical advancements derived from these research programs has been the development by Du Pont of the Rate Process Method (RPM) to estimate long-term system performance. This accelerated test for estimating pressure capability at use conditions is based on the demonstrated Arrhenius principle, relating material strength to temperature. The method is supported by many hundreds of data points at several test temperatures.

RPM estimates enable us to quantify performance of Aldyl® "A" systems. These estimates have shown certain limitations in some 1-1/4 inch and larger Aldyl® pipe installed prior to 1973 which were not previously shown by standard state-of-the-art testing (ASTM D-2837) available at the time. RPM estimates have confirmed that service life of this pipe may be reduced by rock impingement, which is contrary to recommended practice, as communicated previously.

It has now also been shown that the life of pre-1973 1-1/4 inch and larger pipe is shortened at squeeze-off points. For example, RPM estimates show that for squeezed pre-1973 SDR-11 pipe operating at 60 psig and a ground temperature of 70°F (e.g. conditions in parts of the southwestern U.S.) a mean

DU PONT

life of about 20 years, after squeeze, can be expected. When ground temperature is 60°F, however, the mean life of a squeeze point in such pipe is projected to be about 50 years. The effects of temperature, rock impingement and squeeze-off predicted by RPM are being substantiated by actual field experience.

Based on this new information, reinforcement is recommended to extend the life of pre-1973 pipe when squeeze-off procedures are used. Alternatively, through your own field experience you may have developed other methods you have found to be effective to extend life of squeezed polyethylene pipe.

There are a number of suppliers of reinforcement clamps, and an ASTM guide for selection and use of full encirclement type clamps is near completion. Key items of this proposed guide are summarized in the attachment.

RPM estimates show that for Du Pont's current Aldyl® "A" product:

- Resistance to failure as a result of rock impingement has been improved significantly; and

- Long-term performance is unaffected by squeeze-off (provided proper procedures are followed).

We trust this update on laboratory results and field experience will be helpful in managing Aldyl® systems. Our RPM data on squeeze-off, rock impingement, deflection and other conditions are available, should you wish to use them to help characterize your system, and we welcome discussion of these data with you. We look on such exchanges of information as part of our ongoing partnership in the safe, economical distribution of natural gas.

Sincerely,

E. J. Roddy
Manager
Aldyl® Piping Systems, U.S.
SPECIALTY PRODUCTS & SERVICES DIVISION

EJR1:04/dle
8/25/86
Attachment

SUMMARY OF PROPOSED ASTM DOCUMENT

STANDARD GUIDE FOR THE SELECTION AND USE OF FULL ENCIRCLEMENT TYPE BAND CLAMPS FOR REINFORCEMENT OR REPAIR OF POLYETHYLENE GAS PRESSURE PIPE

- Full encirclement band clamps can be used to reinforce PE pipe where it has been squeezed-off.
- The user should confirm that the band clamp manufacturer recommends his product for reinforcement of PE pipe.
- The user should obtain recommended step-by-step installation instructions from the band clamp manufacturer.
- General considerations to determine appropriateness of using band clamps, design requirements for band clamps, and test methods for evaluation are the responsibility of the band clamp manufacturer.
- The band clamp should be long enough so that it extends 2.5 inches beyond each side of the squeeze-off area.
- The PE pipe should be clean and rounded prior to band clamp installation.

This proposed ASTM document is on the current F-17 Main Committee ballot. Several wording changes may occur as the document proceeds through the ASTM ballot process. Since the proposed balloted document cannot be reproduced or quoted, the key items related to reinforcement of squeezed PE pipe have been summarized here. The final approved document may appear in the 1987 Book of ASTM Standards.

EJR1:04/dle
8/25/86

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 3

NTSB Special Investigation Report Brittle-Like Cracking in Plastic Pipe for Gas Service

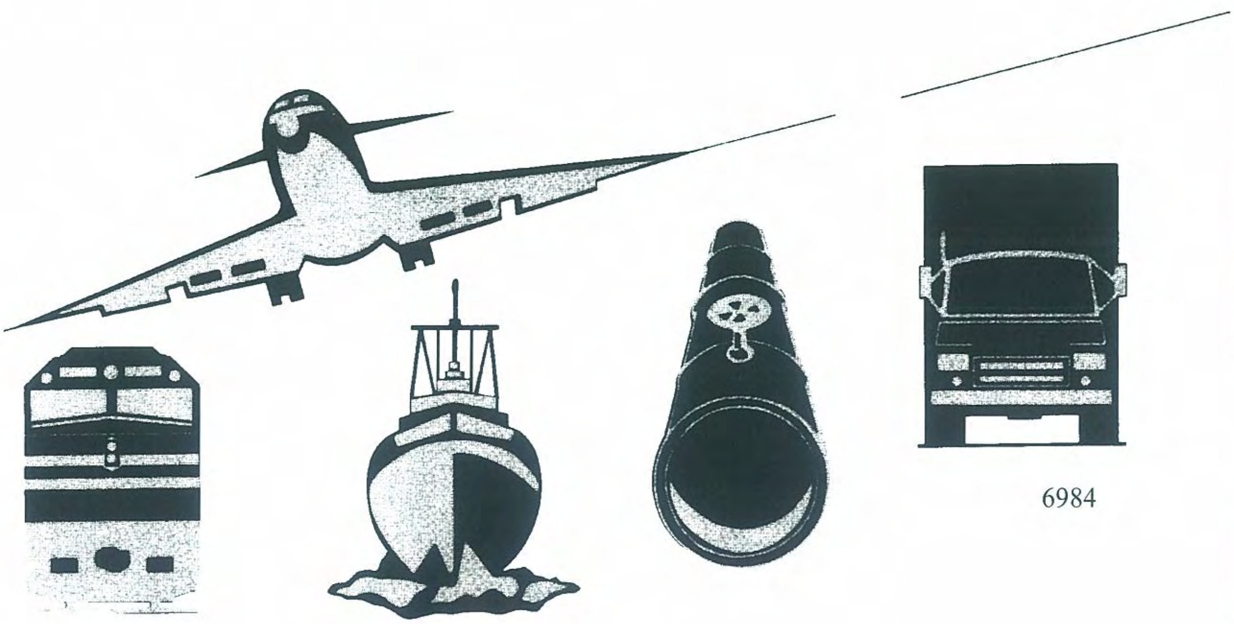
PB98-917001
NTSB/SIR-98/01

NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

SPECIAL INVESTIGATION REPORT

BRITTLE-LIKE CRACKING IN PLASTIC PIPE FOR GAS SERVICE



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Abstract: Despite the general acceptance of plastic piping as a safe and economical alternative to piping made of steel or other materials, the National Transportation Safety Board notes that a number of pipeline accidents it has investigated have involved plastic piping that cracked in a brittle-like manner. This special investigation report concludes that the procedure used in the United States to rate the strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s. As a result, much of this piping may be susceptible to premature brittle-like failures when subjected to stress intensification, and these failures represent a potential public safety hazard.

The safety issues discussed in this report are the vulnerability of plastic piping to premature failures due to brittle-like cracking; the adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains; and performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems.

As a result of this special investigation, the National Transportation Safety Board issued recommendations to the Research and Special Programs Administration, the Gas Research Institute, the Plastics Pipe Institute, the Gas Piping Technology Committee, the American Society for Testing and Materials, the American Gas Association, MidAmerican Energy Corporation, Continental Industries, Inc., Dresser Industries, Inc., Inner-Tite Corporation, and Mueller Company.

The National Transportation Safety Board is an independent Federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable causes of the accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The Safety Board makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

Information about available publications may be obtained by contacting:

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BRITTLE-LIKE CRACKING IN PLASTIC PIPE FOR GAS SERVICE

SPECIAL INVESTIGATION REPORT

Adopted: April 23, 1998
Notation 6984

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C. 20594

CONTENTS

APPENDIXES

INTRODUCTION

The use of plastic piping to transport natural gas has grown steadily over the years because of the material's economy, outstanding corrosion resistance, light weight, and ease of installing and joining. According to the American Gas Association (A.G.A.),[1] the total miles of plastic piping in use in natural gas distribution systems in the United States grew from about 9,200 miles in 1965 to more than 45,800 miles in 1970. By 1982, this figure had grown to about 215,000 miles, of which more than 85 percent was polyethylene.[2] Data maintained by Office of Pipeline Safety (OPS), an office of the Research and Special Programs Administration (RSPA) within the U.S. Department of Transportation (DOT), indicate that, by the end of 1996, more than 500,000 miles of plastic piping had been installed. Plastic piping as a percentage of all gas distribution piping installed each year has also grown steadily, as illustrated in figure 1.

Despite the general acceptance of plastic piping as a safe and economical alternative to piping made of steel or other materials, the Safety Board notes that a number of pipeline accidents it has investigated have involved plastic piping that cracked in a brittle-like manner.[3] (See table 1 for information on three recent accidents.) For example, on October 17, 1994, an explosion and fire in Waterloo, Iowa, destroyed a building and damaged other property. Six persons died and seven were injured in the accident. The Safety Board investigation determined that natural gas had been released from a plastic service pipe that had failed in a brittle-like manner at a connection to a steel main.

[1]See appendix B for brief descriptions of the organizations, associations, and agencies referenced in this report.

[2]Watts, J., "Plastic Pipe Maintains Lion's Share of Market," *Pipeline and Gas Journal*, December 1982, p. 19, and National Transportation Safety Board Special Study--*An Analysis of Accident Data from Plastic Pipe Natural Gas Distribution Systems* (NTSB/PSS-80/1).

[3]The body of the report will make clear the distinction between brittle-like and ductile fractures.

The Safety Board also investigated a gas explosion that resulted in 33 deaths and 69 injuries in San Juan, Puerto Rico, in November 1996.[4] The Safety Board's investigation determined that the explosion resulted from ignition of propane gas that had migrated under pressure from a failed plastic pipe. Stress intensification at a connection to a plastic fitting led to the formation of brittle-like cracks.

The Railroad Commission of Texas investigated a natural gas explosion and fire that resulted in one fatality in Lake Dallas, Texas, in August 1997.[5] A metal pipe pressing against a plastic pipe generated stress intensification that led to a brittle-like crack in the plastic pipe.

A Safety Board survey of the accident history of plastic piping suggested that the material may be susceptible to brittle-like cracking under conditions of stress intensification. No statistics exist that detail how much and from what years any plastic piping may already have been replaced; however, as noted above, hundreds of thousands of miles of plastic piping have been installed, with a significant amount of it having been installed prior to the mid-1980s. Any vulnerability of this material to premature failure could represent a serious potential hazard to public safety.

In an attempt to gauge the extent of brittle-like failures in plastic piping and to assess trends and causes, the Safety Board examined pipeline accident data compiled by RSPA. The examination revealed that the RSPA data are insufficient to serve as a basis for assessing the long-term performance of plastic pipe.

[4]National Transportation Safety Board Pipeline Accident Report--*San Juan Gas Company, Inc./Enron Corp., Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996* (NTSB/PAR-97/01).

[5]Railroad Commission of Texas Accident Investigation No. 97-AI-055, October 31, 1997.

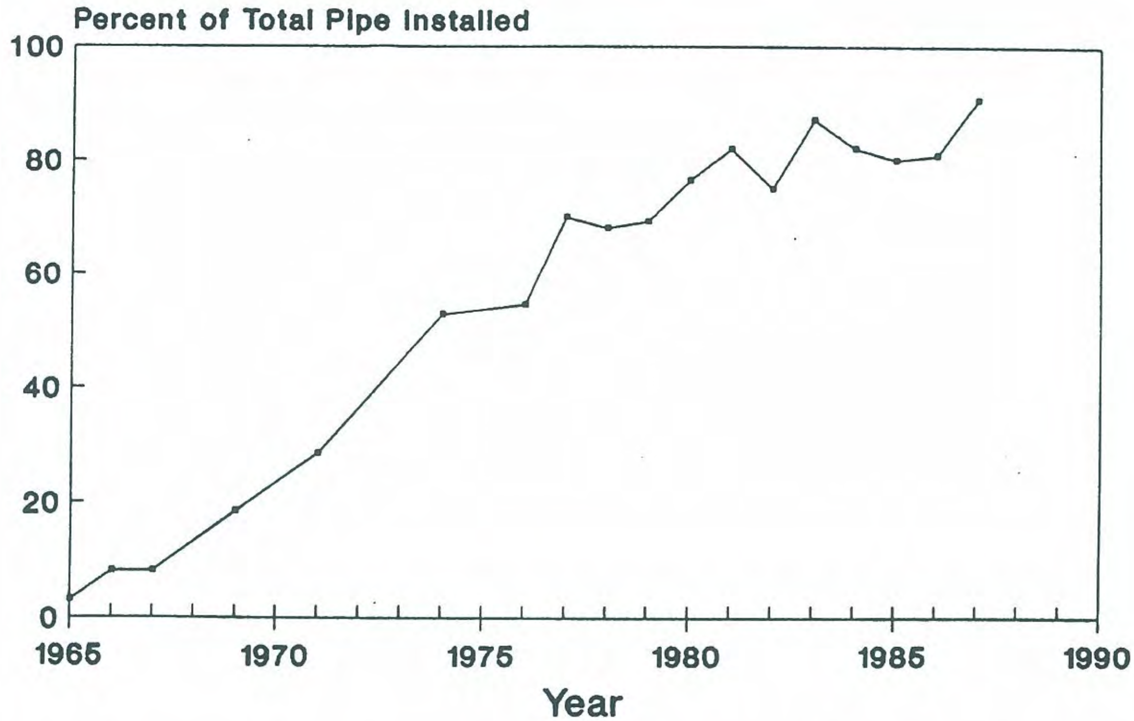

Figure 1 -- Plastic pipe as a percentage of all piping used in gas distribution. (*Source:* Duvall, D.E., "Polyethylene Pipe for Natural Gas Distribution," presented at the Transportation Safety Institute's Pipeline Failure Investigation course, 1997. Data from *Pipeline & Gas Journal* surveys.)

Lacking adequate data from RSPA, the Safety Board reviewed published technical literature and contacted more than 20 experts in gas distribution plastic piping to determine the estimated frequency of brittle-like cracks in plastic piping. The majority of the published literature and experts indicated that failure statistics would be expected to vary from one gas system operator to another based on factors such as brands and dates of manufacture of plastic piping in service, installation practices, and ground temperatures, but they indicated that brittle-like failures, as a nationwide average, may represent the second most frequent failure mode for older plastic piping, exceeded only by excavation damage.

The Safety Board asked several gas system operators about their direct experience with brittle-like cracks. Four major gas system operators reported that they had compiled failure statistics sufficient to estimate the extent of brittle-like failures. Three of those four said that brittle-like failures are the second most frequent failure mode in their plastic pipeline systems. One of these operators supplied data showing that it experienced at least 77 brittle-like failures in plastic piping in 1996 alone.

As an outgrowth of the Safety Board's investigations into the Waterloo, Iowa, San Juan, Puerto Rico, and other accidents, and in view of indications that some plastic piping, particularly older piping, may be subject to premature failure attributable to brittle-like cracking, the Safety Board undertook a special investigation of polyethylene gas service pipe. The investigation addressed the following safety issues:

- The vulnerability of plastic piping to premature failures due to brittle-like cracking;
- The adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains; and

Table 1 -- Recent pipeline accidents involving brittle-like cracking

Accident Location	Pipe Manufacturer	Year Pipe Manufactured	Year of Accident
Waterloo, Iowa	Amdevco/Century	1970	1994
San Juan, Puerto Rico	DuPont	1982	1996
Lake Dallas, Texas	Nipak	1970	1997

- Performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems.

As a result of its investigation, the Safety Board makes three safety recommendations to the Research and Special Programs Administration, one safety recommendation to the Gas Research Institute, three safety recommendations to the Plastics Pipe Institute, one safety recommendation to the Gas Piping Technology Committee, two safety recommendations to the American Society for Testing and Materials, one safety recommendation to the American Gas Association, two safety recommendations to MidAmerican Energy Corporation, two safety recommendations to Continental Industries, Inc., and one safety recommendation each to Dresser Industries, Inc., Inner-Tite Corporation, and Mueller Company.

INVESTIGATION

Accident History

On October 17, 1994, a natural gas explosion and fire in Waterloo, Iowa, destroyed a building and damaged other property. Six persons died and seven were injured in the accident. The Safety Board investigation determined that the source of the gas was a 1/2-inch-diameter plastic service pipe that had failed in a brittle-like manner at a connection to a steel main.[6]

Excavations following the accident uncovered, at a depth of about 3 feet, a 4-inch steel main. Welded to the top of the main was a steel tapping tee manufactured by Continental Industries, Inc. (Continental). Connected to the steel tee was a 1/2-inch plastic service pipe. (See figure 2.) Markings on the plastic pipe indicated that it was a medium-density polyethylene material manufactured on June 11, 1970, in accordance with American Society for Testing and Materials (ASTM) standard D2513. The pipe had been marketed by Century Utility Products, Inc. (Century). The plastic pipe was found cracked at the end of the tee's internal stiffener and beyond the coupling nut.

The investigation determined that much of the top portion of the circumference of the pipe immediately outside the tee's internal stiffener displayed several brittle-like slow crack initiation and growth fracture sites. These slow crack fractures propagated on almost parallel planes slightly offset from each other through the wall of the pipe. As the slow cracks from different planes continued to grow and began to overlap one another, ductile tearing occurred between the planes. Substantial deformation was observed in part of the fracture; however, the initiating cracks were still classified as brittle-like.

Samples recovered from the plastic service line underwent several laboratory tests under the

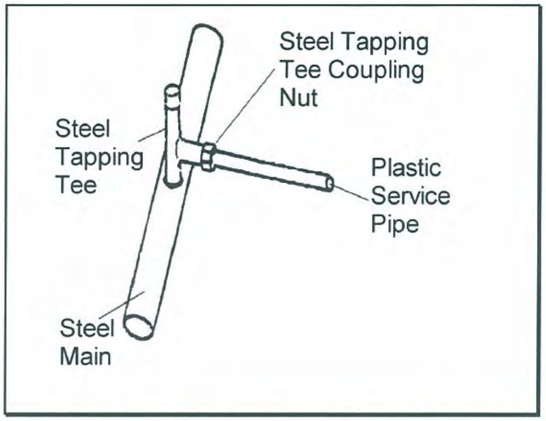

Figure 2 -- Typical plastic service pipe connection to steel gas main. Many connections are protected against shear and bending forces by a plastic sleeve that encloses the service pipe-to-tee connection on either side of the coupling nut.

supervision of the Safety Board. Two of these tests were meant to roughly gauge the pipe's susceptibility to brittle-like cracking. These tests were a compressed ring environmental stress crack resistance (ESCR) test in accordance with ASTM F1248 and a notch tensile test known as a PENT test that is now ASTM F1473. Lower failure times in these tests indicate greater susceptibility to brittle-like cracking under test conditions. The ESCR testing of 10 samples from the pipe yielded a mean failure time of 1.5 hours, and the PENT testing of 2 samples yielded failure times of 0.6 and 0.7 hours. Test values this low have been associated with materials having poor performance histories[7]

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[6]For more detailed information, see Pipeline Accident Brief in appendix A to this report.

[7]Uralil, F. S., et al., *The Development of Improved Plastic Piping Materials and Systems for Fuel Gas Distribution—Effects of Loads on the Structural and Fracture Behavior of Polyolefin Gas Piping*, Gas Research Institute Topical Report, 1/75 - 6/80, NTIS No. PB82-180654, GRI Report No. 80/0045, 1981, and Hulbert, L. E., Cassady, M. J., Leis, B. N., Skidmore, A., *Field Failure Reference Catalog for Polyethylene Gas Piping, Addendum No. 1*, Gas Research Institute Report No. 84/0235.2, 1989, and Brown, N. and Lu, X., "Controlling the Quality of PE Gas Piping Systems by Controlling the Quality of the Resin," *Proceedings Thirteenth International Plastic Fuel Gas Pipe Symposium*, pp. 327-338, American Gas

characterized by high leakage rates at points of stress intensification[8] due to crack initiation and slow crack growth typical of brittle-like cracking.

In late 1996, the Safety Board began an investigation of a November 1996 gas explosion that resulted in 33 deaths and 69 injuries in San Juan, Puerto Rico. The investigation determined that the explosion resulted from ignition of propane gas that, after migrating under pressure from a failed plastic pipe at a connection to a plastic fitting, had accumulated in the basement of a commercial building. The Safety Board concluded that apparent inadequate support under the piping and the resulting differential settlement generated long-term stress intensification that led to the formation of brittle-like circumferential cracks on the pipe.

The Railroad Commission of Texas investigation of a fatal natural gas explosion and fire in Lake Dallas, Texas, in August 1997 determined that a metal pipe pressing against a plastic pipe generated stress intensification that led to a brittle-like crack in the plastic pipe.

The Waterloo, San Juan, and Lake Dallas accidents were only three of the most recent in a series of accidents in which brittle-like cracks in plastic piping have been implicated. In Texas in 1971, natural gas migrated into a house from a brittle-like crack at the connection of a plastic service line to a plastic main.[9] The gas ignited and exploded, destroying the house and burning one person. The investigation determined that vertical loading over the connection generated long-term stress that led to the crack.

A 1973 natural gas explosion and fire in Maryland severely damaged a house, killed three occupants, and injured a fourth.[10] The Safety Board's investigation revealed that a brittle-like crack occurred in a plastic pipe as a result of an occluded particle that created a stress point.

The Safety Board's investigation of a natural gas explosion and fire that resulted in three fatalities in North Carolina in 1975[11] determined that the gas had accumulated because a concrete drain pipe resting on a plastic service pipe had precipitated two cracks in the plastic pipe. Available documentation suggests that these cracks were brittle-like.

A 1978 natural gas accident in Arizona destroyed 1 house, extensively damaged 2 others, partially damaged 11 other homes, and resulted in 1 fatality and 5 injuries.[12] Available documentation indicates that the gas line crack that caused the accident was brittle-like.

A 1978 accident in Nebraska involved the same brand of plastic piping as that involved in the Waterloo accident. A crack in a plastic piping fitting resulted in an explosion that injured one person, destroyed one house, and damaged three other houses.[13] The Safety Board determined that inadequate support under the plastic fitting resulted in long-term stress intensification that led to the formation of a circumferential crack in the fitting. Available documentation indicates that the crack was brittle-like.

A December 1981 natural gas explosion and fire in Arizona destroyed an apartment, damaged five other apartments in the same building, damaged nearby buildings, and injured three occupants.[14] The Safety Board's

Association, Gas Research Institute, Battelle Columbus Laboratories, 1993.

[8]Stress intensification occurs when stress is higher in one area of a pipe than in those areas adjacent to it. Stress intensification can be generated by external forces or a change in the geometry of the pipe (such as at a connection to a fitting).

[9]National Transportation Safety Board Pipeline Accident Report--*Lone Star Gas Company, Fort Worth, Texas, October 4, 1971* (NTSB/PAR-72/5).

[10]National Transportation Safety Board Pipeline Accident Report--*Washington Gas Light Company, Bowie, Maryland, June 23, 1973* (NTSB/PAR-74/5).

[11]National Transportation Safety Board Pipeline Accident Brief--"Natural Gas Corporation, Kinston, North Carolina, September 29, 1975."

[12]National Transportation Safety Board Pipeline Accident Brief--"Arizona Public Service Company, Phoenix, Arizona, June 30, 1978."

[13]National Transportation Safety Board Pipeline Accident Brief--"Northwestern Public Service, Grand Island, Nebraska, August 28, 1978."

[14]National Transportation Safety Board Pipeline Accident Brief--"Southwest Gas Corporation, Tucson, Arizona, December 3, 1981."

investigation determined that assorted debris, rocks, and chunks of concrete in the excavation backfill generated stress intensification that resulted in a circumferential crack in a plastic pipe at a connection to a plastic fitting. Available documentation indicates that the crack was brittle-like.

A July 1982 natural gas explosion and fire in California destroyed a store and two residences, severely damaged nearby commercial and residential structures, and damaged automobiles.[15] The Safety Board's investigation identified a longitudinal crack in a plastic pipe as the source of the gas leak that led to the explosion. Available documentation indicates that the crack was brittle-like.

A September 1983 natural gas explosion in Minnesota involved the same brand of plastic piping as that involved in the Waterloo and Nebraska accidents.[16] The explosion destroyed one house and damaged several others, and injured five persons. The Safety Board's investigation determined that rock impingement generated stress intensification that resulted in a crack in a plastic pipe. Available documentation indicates that the crack was brittle-like.

One woman was killed and her 9-month-old daughter injured in a December 1983 natural gas explosion and fire in Texas.[17] The Safety Board's investigation determined that the source of the gas leak was a brittle-like crack that had resulted from damage to the plastic pipe during an earlier squeezing operation to control gas flow.[18]

A September 1984 natural gas explosion in Arizona resulted in five fatalities, seven injuries, and two destroyed apartments.[19] The Safety Board's investigation determined that a reaction between a segment of plastic pipe and some liquid trapped in the pipe weakened the pipe and led to a brittle-like crack.

During the course of the investigation of the accident at Waterloo, Iowa, the Safety Board learned of several other accidents, not investigated by the Safety Board, that involved cracks in the same brand of plastic piping as that involved in the Waterloo accident. Three of these accidents, which occurred in Illinois (1978 and 1979) and in Iowa (1983), resulted in five injuries and damage to buildings.[20] A 1995 accident in Michigan also involved a crack in this same brand of pipe.[21] Available documentation indicates that the cracks were brittle-like.

Strength Ratings, Ductility, and Material Standards for Plastic Piping

During the 1950s and early 1960s, when plastic piping was beginning to gain acceptance as an alternative to steel piping for the transport of water and gas, no established procedures existed for rating the strength of materials intended for use in plastic pressure piping.

In November 1958, the Thermoplastic Pipe Division of the Society of the Plastics Industry organized a group called the Working Stress Subcommittee.[22] The subcommittee, in January 1963, issued a procedure (hereinafter referred to as the PPI procedure) that specified a uniform protocol for rating the strength of materials used

[15]National Transportation Safety Board Pipeline Accident Brief--"Pacific Gas and Electric Company, San Andreas, California, July 8, 1982."

[16]National Transportation Safety Board Pipeline Accident Brief--"Northern States Power Company, Newport, Minnesota, September 19, 1983."

[17]National Transportation Safety Board Pipeline Accident Brief--"Lone Star Gas Company, Terell, Texas, December 9, 1983."

[18]Plastic pipe is sometimes squeezed to control the flow of gas. In some cases, squeezing plastic pipe can damage it and make it more susceptible to brittle-like cracking.

[19]National Transportation Safety Board Pipeline Accident Report--*Arizona Public Service Company Natural Gas Explosion and Fire, Phoenix, Arizona, September 25, 1984* (NTSB/PAR-85/01).

[20]Illinois Commerce Commission accident reports dated September 14, 1978, and December 4, 1979. Iowa State Commerce Commission accident report dated August 29, 1983.

[21]Research and Special Programs Administration Incident Report—"Gas Distribution System," Report No. 318063, January 8, 1996.

[22]This subcommittee was subsequently made into a permanent unit and was renamed the Hydrostatic Stress Board.

in the manufacture of thermoplastic pipe in the United States. In March 1963, the Thermoplastic Pipe Division adopted its current name, the Plastics Pipe Institute (PPI).

On July 1, 1963, the PPI established a voluntary program of listing the material strengths of plastic piping materials, specifically, those materials designed for water applications. To apply for a PPI listing, applicants sent strength test data to the PPI, often accompanied by the manufacturer's analysis of the data and a proposed material strength rating. The PPI would analyze the data and, if warranted, list the material for the calculated strength. The PPI did not certify or approve the material received or validate the data submitted, nor did it audit or inspect those submitting data.[23]

In simplified terms, the PPI procedure, which is performed by the materials manufacturers themselves, involves recording how much time it takes stressed pipe samples to rupture at a standardized temperature of 73 °F. The stresses used in the tests are recorded as "hoop stress," which is tensile stress in the wall of the pipe in a circumferential orientation (hence the term "hoop") due to internal pressure. Although hoop stress is expressed in pounds per square inch, it is a value quite different from the pipe's internal pressure.

The testing process involves subjecting pipe samples to various hoop stress levels, and then recording the time to rupture. For some samples at some pressures, rupture will occur in as little as 10 hours. As hoop stress is reduced, the time-to-failure increases. At some hoop stress level, at least one of the tested specimens will not rupture until at least 10,000 hours (slightly more than 1 year). After the rupture data points (hoop stresses and times-to-failure) for this material have been recorded, the data points are plotted on log-log coordinates as the relationship between hoop stress and time-to-failure. (See figure 3.) A mathematically developed "best-fit" straight line is correlated with the data points to represent the material's resistance to rupturing at various hoop stress levels.

Once the best-fit straight line is calculated to 10,000 hours, it is extrapolated to 100,000 hours (about 11 years). The hoop stress level that coincides with the point at which the line intersects the 100,000-hour time line represents the calculated long-term hydrostatic strength of that particular material.

To simplify the ratings and facilitate standardization, the PPI procedure grouped materials with similar long-term hydrostatic strength ranges into "hydrostatic design basis" categories. For example, those materials having long-term hydrostatic strengths between 1200 and 1520 psi were grouped together and assigned a hydrostatic design basis of 1250 psi. Those materials having long-term hydrostatic strengths between 1530 and 1910 psi were grouped together and assigned a hydrostatic design basis of 1600 psi.

To help ensure the validity of the mathematically derived line, the PPI procedure required the submission of all rupture data points. It further specified the minimum number of data points and minimum number of tested lots. The procedure employed statistical tests to verify the quality of data and quality of fit to the mathematically derived line. These measures excluded materials when the data demonstrated excessive data scatter due to either inadequate quality of data or deviation from straight line behavior through 10,000 hours.[24]

The PPI procedure, after some refinement, was issued as an ASTM method in 1969 (ASTM D2837). The PPI adopted a policy document[25] for PPI's listing service in 1968, which remained under PPI jurisdiction.

[23]As a result of Safety Board inquiries to the PPI about its inability to verify the actual data submitted, the institute, in 1997, revised its policy document for its listing service to require a signed statement from applicants that data accompanying applications for a PPI listing are complete, accurate, and reliable.

[24]The PPI procedure also had restrictions on the degree of slope of the straight line so that the material's strength would not excessively diminish beyond 100,000 hours.

[25]Plastics Pipe Institute, *Policies and Procedures for Developing Recommended Hydrostatic Design Stresses for Thermostatic Pipe*, PPI-TR3-July 1968.

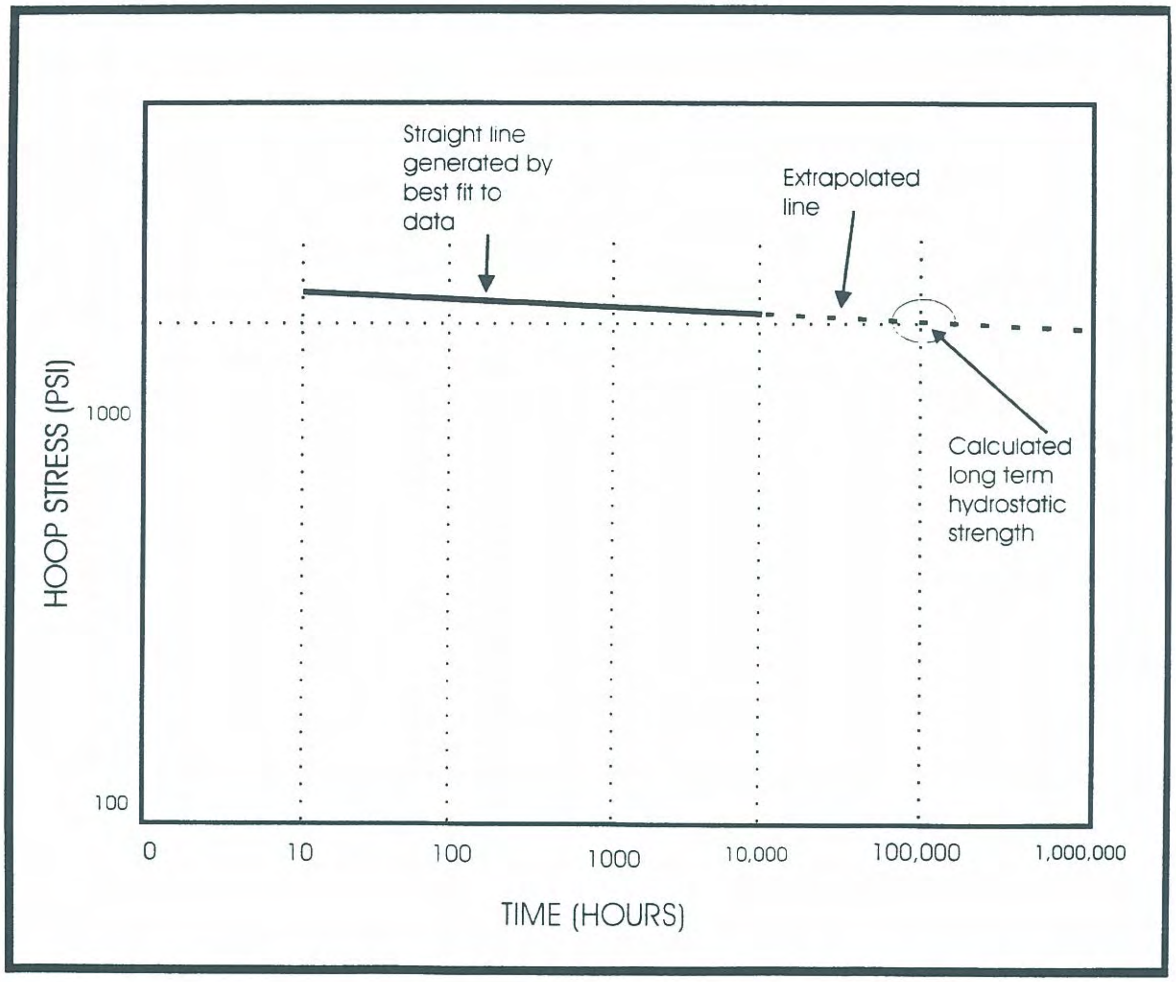

Figure 3 -- Stress rupture data plotted as best-fit straight line and extrapolated to determine long-term hydrostatic strength. (Derived from *A.G.A. Plastic Pipe Manual for Gas Service.)*

When polyethylene pipe fails during laboratory stress rupture testing at 73 °F, it fails primarily by means of ductile fractures, which are characterized by substantial visible deformation (see figure 4). During stress rupture tests, if hoop stress on the test piping is decreased, the time-to-failure increases, and the amount of deformation apparent in the failure decreases.[26] In pipe subjected to prolonged stress rupture testing, slit fractures[27] may begin to appear at some point (depending on the specific polyethylene resin material). Figure 5 shows a slit fracture that resulted from a stress rupture test. The PPI procedure did not differentiate between ductile and slit failure types, and, based on most available laboratory test data (at 73 °F),[28] assumed that both types of

[26]Mruk, S. A., "The Ductile Failure of Polyethylene Pipe," *SPE Journal*, Vol. 19, No. 1, January 1963.

[27]Because of the frequent lack of visible deformation associated with them, slit fractures are also referred to as brittle-like fractures.

[28]Kulhman, H. W., Wolter, F., Sowell, S., Smith, R. B., *Second Summary Report, The Development of Improved Plastic Pipe for Gas Service, Prepared for the American Gas Association*, Battelle Memorial Institute, covering the work from mid-1968 through 1969. Stress rupture tests were performed using methane and nitrogen as the internal pressure medium and air as the outside environment. Some experts have advised the Safety Board that stress rupture testing showing time-to-failure in the slit mode may vary with different pressure media and

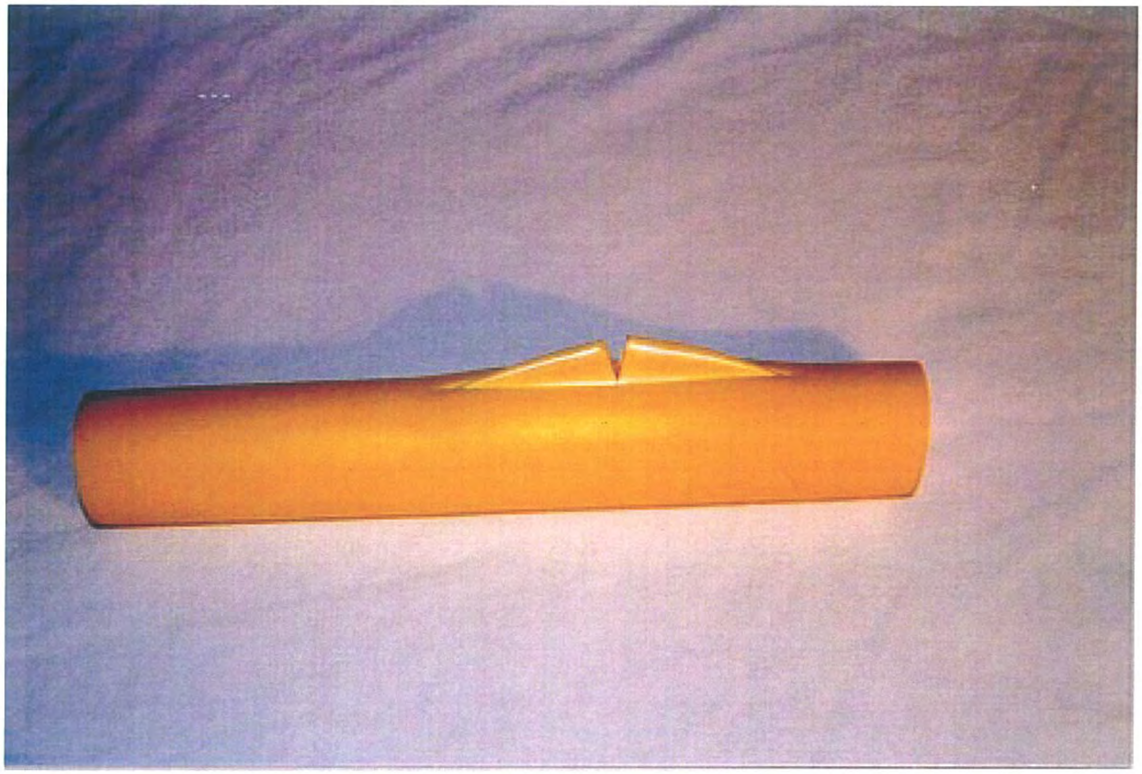

Figure 4 -- Ductile fracture resulting from stress rupture test. Note substantial deformation (ballooning) at the failure.

failures would be described by the same extrapolated (straight) line.

In 1963-64, the National Sanitation Foundation[29] amended its standard for plastic piping used for potable water service to require that manufacturers furnish evidence of having an appropriate strength rating in accordance with the PPI procedure. Manufacturers then decided to utilize the PPI listing service, having determined that this was the most convenient way to furnish the required evidence.

In 1966, the ASTM issued ASTM D2513, the society's first standard specification covering polyethylene plastic piping for gas service.[30] ASTM D2513 made reference to long-term hydrostatic strength and hydrostatic design stress and included an appendix defining these terms in accordance with the PPI procedure.[31] It also required that polyethylene pipe meet certain requirements of ASTM D2239 (a polyethylene pipe specification for water service), which also included references to the PPI procedure. ASTM D2513 did not explicitly require materials to have a PPI listing.

environments and that Battelle Memorial Institute's choices for these fluids may have contributed to the slow recognition in the United States of a downturn in the stress rupture line.

[29]Now known as NSF International.

[30]This standard also included plastic piping materials other than polyethylene.

[31]Although adherence to ASTM appendixes is not mandatory, the PPI procedure was the only industry-accepted mechanism to determine long-term hydrostatic strength and hydrostatic design stress.

Figure 5 -- Slit fracture resulting from a stress rupture test conducted at 100 °F. Note lack of deformation visible in the fracture. This pipe was manufactured by DuPont in 1977. After failing Minnegasco's incoming inspection tests, the pipe was subjected to stress rupture testing. (*Source:* Henrich, R.C., and Funck, D.L., "Effects of ESCR Variation on Some Other Properties of Plastic Pipe." *Proceedings, Eighth Annual Plastic Fuel Gas Pipe Symposium, 1983.)*

Even without an explicit requirement, some manufacturers voluntarily obtained PPI listings for their resin materials[32] intended for gas use, and some others,[33] as noted above, obtained PPI listings for their resins that were intended for water use (but were similar to their resins intended for gas service) as a way of meeting National Sanitation Foundation requirements.

In 1967, the United States of America Standards Institute B31.8 code,[34] *Gas Transmission and Distribution Piping Systems*, for the first time recognized the suitability of plastic piping for gas distribution service and included requirements for the pipings' use. The 1966 issuance of ASTM D2513 and the 1967 inclusion of plastic piping within B31.8 cleared the way for the general use of plastic piping for gas distribution.[35] B31.8 included a design equation (see discussion below), and although the code, like the ASTM standard, did not explicitly require a PPI listing, it did require that material used to manufacture plastic pipe establish its long-term hydrostatic strength in accordance with the PPI procedure.

[32]Resins are polymer materials used for the manufacture of plastics.

[33]For example, E. I. du Pont de Nemours & Company, Inc., and Union Carbide Corporation.

[34]Now known as ASME B31.8.

[35]*A.G.A. Plastic Pipe Handbook for Gas Service*, American Gas Association, Catalog No. X50967, April 1971.

On August 12, 1968, the Natural Gas Pipeline Safety Act was enacted, requiring the DOT to adopt minimum Federal regulations for gas pipelines. In December 1968, the DOT instituted interim Federal regulations by federalizing the State pipeline safety regulations that were in place at the time. The DOT, having concluded that the majority of the States required compliance with the 1968 version of B31.8, adopted that version of the code for the Federal regulations covering those States not yet having their own natural gas pipeline safety regulations.

Most of these Federal interim standards were replaced in November 1970 by 49 *Code of Federal Regulations* (CFR) 192; however, the interim provisions concerning the design, installation, construction, initial inspection, and initial testing of new pipelines remained in effect until March 1971. At that time, 49 CFR 192 incorporated the design equation for plastic pipe from B31.8 and also required that plastic piping conform to ASTM D2513.[36]

The 1967 version of B31.8 introduced fixed design factors[37] (subsequently incorporated into 49 CFR 192) as a catch-all mechanism to account for various influences on pipe performance and durability. These influences included external loadings, limitations of and imprecision in the PPI procedure, variations in pipe manufacturing, handling and storage effects, temperature fluctuations, and harsh environments.[38] A design equation was used to determine the allowable gas service pipe pressure rating based on the hydrostatic design basis category, pipe dimensions, and design factor.[39] The design basis for plastic pipe thus used internal pressures as a design criterion but did not directly take into account additional stresses that could be generated by external loadings, despite the fact that field failures in plastic piping systems were frequently associated with external loads but were rarely attributable to internal pressure effects alone.[40]

Kulmann and Mruk have reported that no direct basis was established to design for external loads because:

- The industry had no easy means of quantifying external loads and their effects on plastic piping systems;[41] and
- Many in the industry believed that plastic piping, like steel and copper piping, behaved as a ductile material that would withstand considerable deformation before undergoing damage, thus alleviating and redistributing local stress concentrations that would crack brittle materials such as cast iron. This belief resulted from short-term laboratory tests showing that plastic piping had enormous capacity to deform before rupturing.[42]

Because of plastic piping's expected ductile behavior, many manufacturers believed it safe to base their designs on average distributed stress concentrations generated primarily by internal pressure and, within reason, to neglect localized stress concentrations. They believed such stress would be reduced by localized yielding, or deformation. Mruk and Palermo have pointed out that design protocols were predicated on the assumption of such ductile behavior.[43]

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[36]RSPA reviews revised editions of ASTM D2513 for acceptability before referencing them in 49 CFR 192.

[37]A design factor is similar to a safety factor, except that a design factor attempts to account for other factors not directly included within the design equation that significantly affect the durability of the pipe.

[38]Reinhart, F. W., "Whence Cometh the 2.0 Design Factor," Plastics Pipe Institute, undated, and Mruk, S. A., "Validating the Hydrostatic Design Basis of PE Piping Materials."

[39]The design equation (with the current design factor, 0.32) can be found in 49 CFR 192.121, although 192.121 erroneously references the long-term hydrostatic strength instead of the hydrostatic design basis category. RSPA is currently conducting rulemaking activities to correct this error.

[40]Kulmann, H. W., Wolter, F., Sowell, S., "Investigation of Joint Performance of Plastic Pipe for Gas Service," *1970 Operating Section Proceedings*, American Gas Association, pp. D-191 to D-198.

[41]Kulmann, Wolter, and Sowell.

[42]Mruk, S. A., "Validating the Hydrostatic Design Basis of PE Piping Materials."

[43]Mruk, S. and Palermo, E., "The Notched Constant

Figure 6 -- Slit fracture on a polyethylene pipe manufactured by DuPont that was found leaking and removed from a gas piping system.

In contrast, cast iron piping has recognized brittle characteristics. The design basis for cast iron therefore does not assume that localized yielding or deformation will reduce stress intensification. As a result, the design protocol for cast iron includes the quantification and direct input of external loading factors that can generate localized stress intensification.[44]

Failures in polyethylene piping that occur under actual service conditions are frequently slit failures; ductile failures are rare.[45] Figure 6 shows a slit (brittle-like) fracture in a pipe that was found leaking and had to be replaced. A rock pressing against the plastic pipe generated long-term stress intensification that led to the formation of the brittle-like crack. Slit failures in polyethylene, whether occurring during stress rupture testing or under actual service conditions, result from crack initiation and slow crack growth and are similar to brittle cracks in other materials in that they can occur with little or no visible deformation.[46]

Tensile Load Test: A New Index of the Long Term Ductility of Polyethylene Piping Materials," summary of presentation given in the Technical Information Session hosted by ASTM Committee F17's task group on Project 62-95-02, held in conjunction with ASTM Committee F17's November 1996 meetings, New Orleans, LA.

[44]Mruk and Palermo and Hunt, W. J., "The Design of Grey and Ductile Cast Iron Pipe," *Cast Iron Pipe News*, March/April 1970.

[45]Mruk, S. A., "Validating the Hydrostatic Design Basis of PE Piping Materials," and Bragaw, C. G., "Fracture Modes in Medium-Density Polyethylene Gas Piping Systems," *Plastics and Rubber: Materials and Applications*, pp. 145-148, November 1979.

[46]Mruk and Palermo have quantified and discussed the deformation in brittle-like failures in: Mruk, S. and Palermo, E., "The Notched Constant Tensile Load Test: A New Index of the Long Term Ductility of Polyethylene

Figure 7 -- Interior of polyethylene pipe from San Juan pipeline accident showing brittle-like crack with no visible deformation.

Figure 7 illustrates brittle-like cracking that was found in a plastic pipe involved in the fatal propane gas explosion in San Juan, Puerto Rico, in November 1996. That pipe was manufactured in 1982 by E. I. du Pont de Nemours & Company, Inc., (DuPont) at its Pencador, Delaware, plant. Apparently, differential settlement resulting from inadequate support under the piping generated long-term stress intensification that led to the formation of brittle-like cracks in the pipe.

Figure 8 shows a brittle-like crack that was found in a plastic pipe involved in the fatal natural gas explosion and fire in Lake Dallas, Texas, in August 1997. That pipe was manufactured in 1970 by Nipak, Inc. A metal pipeline pressing against the plastic pipe generated long-term stress intensification that led to the crack.

During the 1960s and 1970s, some experts began to question the validity of the PPI procedure's assumption of a continuing, gradual straight-line decline in strength (figure 3). [47] By the late 1970s and early 1980s, the plastic piping industry in the United States realized that

Piping Materials," summary of presentation given in the Technical Information Session hosted by ASTM Committee F17's task group on Project 62-95-02, held in conjunction with ASTM Committee F17's November 1996 meetings, New Orleans, LA, and Mruk, S. A., "Validating the Hydrostatic Design Basis of PE Piping Materials," pp. 202-214, 1985.

[47]The 1971 *A.G.A. Plastic Handbook for Gas Service* noted that the cause and mechanisms of brittle fractures sometimes found with long-term stress rupture testing was not yet well established. Two of the pioneering papers in the United States to suggest a downturn in long-term hydrostatic strength with brittle-like failures or in elevated temperature testing were: Mruk, S. A., "The Ductile Failure of Polyethylene Pipe," *SPE Journal*, Vol. 19, No. 1, January 1963, and Davis, G. W., "What are Long Term Criteria for Evaluating Plastic Gas Pipe?" *Proceedings Third A.G.A. Plastic Pipe Symposium*, American Gas Association, pp. 28-35, 1971.

Figure 8 -- Brittle-like crack in pipe involved in August 1997 accident in Lake Dallas, Texas. The crack extends from the left to upper right of the area defined by the ellipse.

testing piping materials at elevated temperatures was a way to accelerate failure behavior that would occur much later at lower temperatures (such as 73 °F). Based on data derived from elevated-temperature testing, the industry concluded that the gradual straight-line decline in strength assumed by the PPI procedure was not valid. Instead, two distinct failure zones were indicated for polyethylene piping in stress rupture testing. (See figure 9.) The first zone is characterized by the gradual straight-line decline in strength accompanied primarily by ductile fractures. The first zone gradually transitions to the second zone, which is characterized by a more rapid decline in strength accompanied by brittle-like fractures only. The time and magnitude of this more rapid decline in strength varies by type and brand of polyethylene. Piping manufacturers have worked to improve their products' resistance to slit-type failures and thus to push this downturn further out in time. The PPI procedure did not account for this downturn, and the difference between the actual falloff shown in figure 9 and the projected straight-line strengths shown in figure 3 for listed materials became more pronounced as the lines were extrapolated beyond 100,000 hours.

As manufacturers steadily improved their formulations to delay the onset of the downturn in long-term strength and associated brittle-like behavior, PPI and ASTM industry standards were upgraded to reflect what the major manufacturers were able and willing to accomplish.[48] Accordingly, and because a consensus of manufacturers recognized the relationship between

[48]Both the PPI and the ASTM work on a consensus principle, meaning that requirements are put into place only when a consensus of voting members is reached. The PPI is a manufacturers' organization. With respect to the ASTM technical committee that generates requirements for plastic piping, the major piping manufacturers participate actively in the committee and are in a position to influence ASTM strength rating requirements.

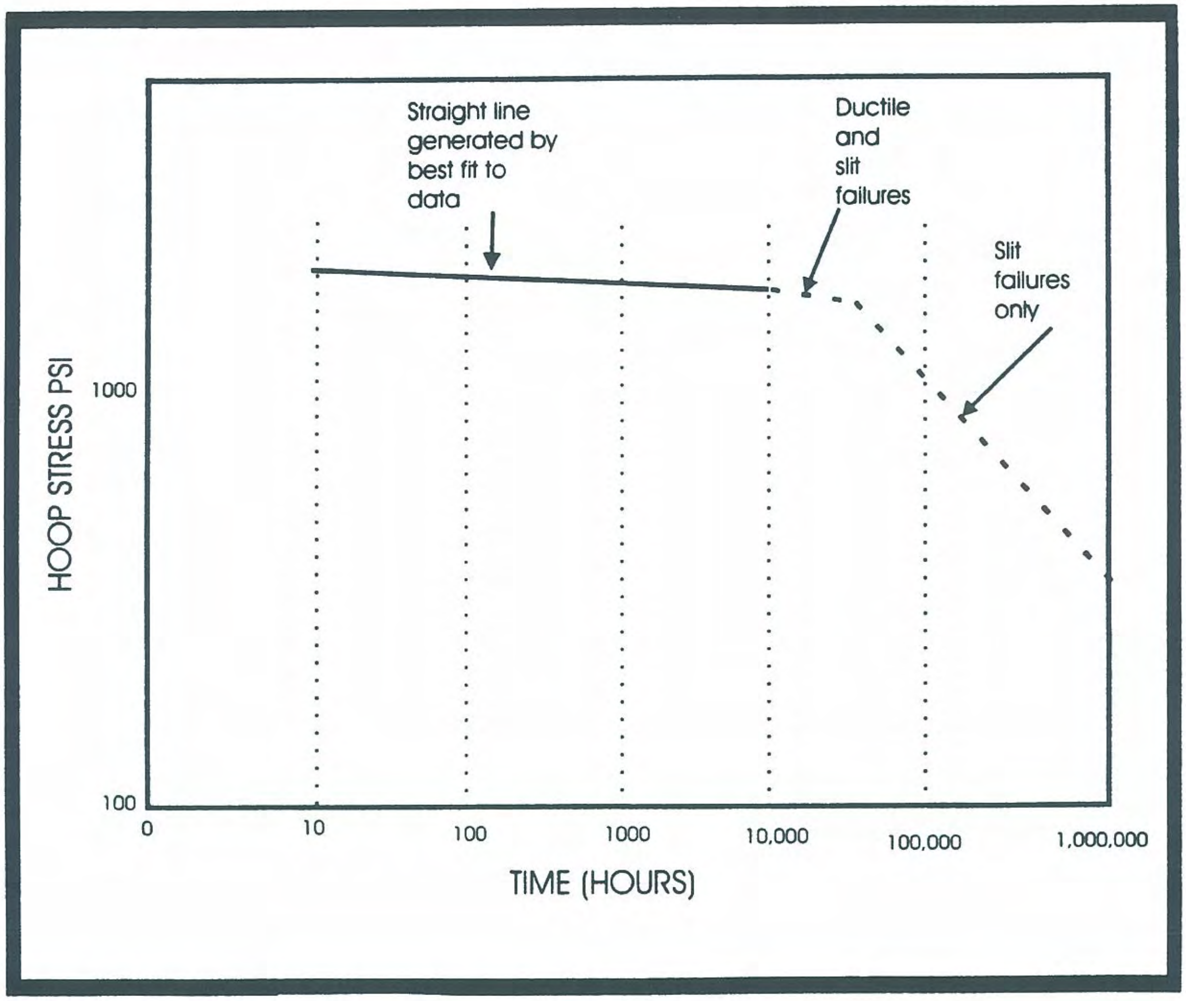

Figure 9 -- Stress rupture data plotted as best-fit straight line transitioning to downturn in strength. (Derived from *A.G.A. Plastic Pipe Manual for Gas Service.*)

improved elevated-temperature properties and improved longer term pipe performance, the PPI in 1982 recommended that ASTM D2513 specify a minimum acceptable hydrostatic strength at 140 °F. In 1984, ASTM D2513 included a statement in its non-mandatory appendix that gas pipe materials should have a specified long-term hydrostatic strength at 140 °F. In the 1988 edition, this requirement was moved to the mandatory section of the standard. This strength at 140 °F was calculated the same way that the 73 °F strength was calculated—data demonstrating a straight line to 10,000 hours was assumed to extrapolate to 100,000 hours without a downturn.

Gradually, more manufacturers obtained PPI listings for their resins intended for gas service, and by the early to mid-1980s, virtually all resins used for gas service had PPI listings. At that time, a consensus of manufacturers supported a change within ASTM D2513 to require PPI listings. In 1985, ASTM D2513 was revised to require that materials for gas service have a PPI listing.

By 1985, manufacturers reached a consensus to exclude materials that deviated from the 73 °F extrapolation before 100,000 hours. The PPI adopted this restriction and advised the industry that, effective January 1986, all materials not demonstrating straight-line performance to 100,000 hours would be dropped from its listing.[49] In 1988, ASTM D2837 also included the restriction.[50] The new PPI and ASTM requirements had no effect on pipe installed prior to the effective date of the requirements.

On August 20, 1997, after manufacturers reached a consensus, the PPI issued notice that, effective January 1999, in order for materials to retain their PPI listings for long-term hydrostatic strength at temperatures above 73 °F (for example, at 140 °F), these materials will have to demonstrate (mathematically, via elevated-temperature testing) that a downturn does not exist prior to 100,000 hours or, alternatively, if a downturn does exist before 100,000 hours, the strength rating will be reduced to reflect the point at which the calculated downturn in strength intercepts 100,000 hours. An ASTM project has been initiated to incorporate this requirement within ASTM D2837. The Safety Board also notes that the PPI has endorsed a proposal to have ASTM D2513 require polyethylene piping to have no downturn in stress rupture testing at 73 °F before 50 years, as mathematically determined in elevated-temperature tests.

All available evidence indicates that polyethylene piping's resistance to brittle-like cracking has improved significantly through the years. Several experts in gas distribution plastic piping have told the Safety Board that a majority of the polyethylene piping manufactured in the 1960s and early 1970s had poor resistance to brittle-like cracking, while only a minority of that manufactured by the early 1980s could be so characterized.[51] Several gas system operators have told the Safety Board that they are aware of no instances of brittle-like cracking with their own modern polyethylene piping installations.

[49]Mruk, S. A., "Validating the Hydrostatic Design Basis of PE Piping Materials."

[50]*A.G.A. Plastic Pipe Manual for Gas Service*, American Gas Association, Catalog No. XR 9401, 1994.

[51]A number of these experts considered material to have poor resistance to brittle-like cracking if the material was shown to have a downturn in strength associated with brittle-like fractures in stress rupture testing (at 73 °F) before 100,000 hours.

Century Pipe Evaluation and History

The Safety Board's investigation of the Waterloo, Iowa, accident determined that the pipe involved in the accident had been manufactured by Amdevco Products Corporation (Amdevco) in Mankato, Minnesota. Amdevco's Mankato plant first began producing plastic pipe in 1970, with plastic piping for gas service as its only piping product. Amdevco made the pipe from Union Carbide's Bakelite DHDA 2077 Tan 3955 (hereinafter referred to as DHDA 2077 Tan) resin material. Century Utility Products, Inc., marketed the pipe to Iowa Public Service Company,[52] and Century's name was marked on the pipe. Century and Amdevco formally merged in 1973. The combined corporation went out of business in 1979.

Because Amdevco/Century no longer exists, Safety Board investigators could locate no records to indicate the qualification steps Amdevco may have performed before Century marketed its pipe to Iowa Public Service Company. A plastic pipe manufacturer would normally have obtained documentation from its resin supplier indicating that the resin material had a sufficient long-term hydrostatic strength. Code B31.8 required and ASTM D2513 recommended that polyethylene pipe manufacturers perform certain quality control tests on production samples, including twice-per-year sustained pressure tests.

Like many gas operators of that time, Iowa Public Service Company (now MidAmerican Energy Corporation), which had installed the Waterloo piping in 1971, had no formal program for testing or evaluating products. According to MidAmerican Energy, the company accepted representations from a principal of Century, a former DuPont employee, who portrayed himself as being intimately involved with the development and marketing of DuPont's polyethylene piping. MidAmerican Energy has reported that these representations included assertions that Century

[52]Because of a series of organizational changes and mergers, the name of the owner/operator of the gas system at Waterloo, Iowa, has changed over the years. In 1971, Iowa Public Service Company installed the gas service that ultimately failed. At the time of the accident, the gas system operator was Midwest Gas Company. The current operator is MidAmerican Energy Corporation.

plastic pipe met industry standards and had the same formulation as DuPont's plastic pipe. In 1970, according to MidAmerican Energy officials, Century offered Iowa Public Service Company attractive commercial terms for its product, with the result that, in 1970, when Amdevco first started to manufacture pipe, Iowa Public Service Company began purchasing all of its plastic pipe from Century.[53]

Before the Waterloo accident, a previous accident involving Century pipe had been reported in the Midwest Gas (the operator at the time of the accident) system. That accident occurred in August 1983 in Hudson, Iowa, and resulted in multiple injuries. Midwest Gas, attributing this accident to a rock pressing into the pipe, considered it an isolated incident. During 1992-94, the company had two significant failures with pipe fittings involving brittle-like cracks in Century pipe. Sections of the failed pipe were sent to the two affected pipe fitting manufacturers, and one responded that nothing was wrong with the fitting, suggesting instead that the problem might rest with the piping material.

MidAmerican Energy reported that, as a result of these two failures, Midwest Gas directed inquiries to other utilities operating in the Midwest and, in May 1994, learned of one other accident involving Century pipe. In June 1994, Midwest Gas decided to send samples of Century polyethylene piping to an independent laboratory for test and evaluation. The sample collection was in process at the time of the Waterloo accident. In August 1995, Midwest Gas issued a report, based on the laboratory testing, concluding that the Century samples had poor resistance to slow crack growth.

Subsequent to the accident, Midwest Gas worked to determine if its installations with Century plastic piping had had higher rates of failure than those with piping from other manufacturers. After analyzing the data, Midwest Gas concluded that the piping installations with Century piping had failure rates that were significantly higher than those installations with plastic piping from other manufacturers. Based on this analysis, as well as on other factors—including the severity and consequences of leaks involving Century piping, the laboratory test results, recommendations from two manufacturers of pipe fittings cautioning against use of their fittings with Century pipe because of the pipe's poor resistance to brittle-like cracking, and interviews with field personnel—MidAmerican Energy (the current operator) has replaced all its known Century piping with new piping, completing the replacement program in 1997.

Safety Board investigators found little additional documentation regarding qualification tests of Century plastic pipe by other gas system operators having Century pipe in service. A reference was found to a 1971 Northern States Power Company Testing Department progress report stating that Century pipe complied with ASTM D2513, and that the pipe was acceptable for use with DuPont polyethylene fittings. The actual progress report and records of any tests that may have been performed were not located.[54]

Union Carbide DHDA 2077 Tan Resin -- The resin used to manufacture the pipe involved in the Waterloo accident was DHDA 2077 Tan. To examine how Union Carbide qualified this material requires some background.

During the late 1960s, several companies manufactured plastic resin and plastic pipe for the gas distribution plastic piping market. At that time, Union Carbide began a process of modifying its DHDA 2077 Black resin (for water distribution) in order to create a DHDA 2077 Tan resin for the gas distribution industry.

Before Union Carbide could market its DHDA 2077 Tan resin material for natural gas service, it needed to generate stress rupture data, in accordance with the PPI procedure, that would support the long-term hydrostatic

[53]Iowa Public Service Company continued to purchase DuPont plastic piping fittings until fittings were available from Century. MidAmerican Energy made technical procurement decisions via a Gas Standards Committee. According to company officials, the company has implemented a process to ensure that it continues to receive quality products once the products have passed an initial qualification process.

[54]Northern States Power is based in St. Paul, Minnesota.

strength rating it was assigning to the material (a requirement of the interim Federal regulations effective at that time).[55] The company had three resources to draw upon to support the hydrostatic design basis category: (1) internal stress rupture data on its DHDA 2077 Tan resin, (2) a PPI listing already obtained on its similar black resin, and (3) additional internal stress rupture data on its black resin.

On June 11, 1968, Union Carbide began stress rupture testing on specimens of pipe made from a pilot-plant batch of its newly developed DHDA 2077 Tan resin. The results of this testing supported Union Carbide's declared hydrostatic design basis category for DHDA 2077 Tan. The number of data points generated by these stress rupture tests for the DHDA 2077 Tan was less than that required by PPI procedure; however, Union Carbide began to market the product for use in gas systems based on these tests and on additional testing performed on the company's black resin material.

Because Union Carbide had not developed the PPI-prescribed number of data points on its DHDA 2077 Tan resin before marketing the product, Safety Board investigators reviewed the data the company developed on its black resin. A review of Union Carbide's laboratory notebooks revealed that a number of adverse data points Union Carbide developed for its black resin were not submitted to the PPI when the company applied for a PPI listing for the black material.[56]

Union Carbide first made a commercial version of its DHDA 2077 Tan resin during the spring of 1969, and in April 1970, a first shipment of 80,000 pounds of DHDA 2077 Tan resin was shipped to Amdevco's Mankato plant. The next shipment of the material to Amdevco was not until 1971. Based on Amdevco's June 11, 1970, manufacturing date for the Waterloo pipe, Union Carbide manufactured, sold, and delivered the resin used to make the Waterloo pipe between the spring of 1969 and June 11, 1970, and the resin used to make the pipe involved in the Waterloo accident probably was included in the April 1970 shipment.

Union Carbide began, on December 3, 1970, additional stress rupture tests on its commercial DHDA 2077 Tan resin. These tests generated the results to further support its claimed long-term hydrostatic strength and also provided the number of data points required by the PPI procedure. Additional stress rupture tests on the commercial DHDA 2077 Tan resin beginning on December 28, 1970, and again on January 6, 1972, further supported the material's long-term hydrostatic strength.

During the late 1960s and 1970s, Minnegasco, a gas system operator based in Minneapolis, Minnesota, routinely employed a 1,000-hour sustained pressure test at 100 °F detailed in ASTM D2239 and a 1,000-hour sustained pressure test at 73 °F detailed in ASTM D2513 to qualify plastic piping for use in its system. Minnegasco went beyond the requirements of ASTM standards by continuing both versions of the testing beyond 1,000 hours until eventual failure occurred. The company used this information to evaluate the relative strengths of different brands of piping.

In 1969-70, Minnegasco began a series of tests on samples from five different suppliers of plastic piping made from DHDA 2077 Tan resin. On March 3, 1972, Minnegasco's laboratory issued an internal report that contained the results of its latest tests on piping made from the resin and referenced earlier tests on several brands of piping (including Amdevco/Century) that were also made from it. Based on this report, Minnegasco rejected for use in its gas system the DHDA 2077 Tan resin. According to the report, the company rejected the material because (1) none of the pipe samples made from this resin could consistently pass the 1,000-hour sustained pressure test at

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[55]The company was required to follow the PPI procedure in developing the necessary stress rupture data, but no requirement existed for those data to be submitted to the PPI or for the PPI to assign a listing before the tested material could be marketed.

[56]Although the PPI procedure required the submission of all valid data points for statistical analysis, the Union Carbide employee who managed the data indicated that he believed he could discard data that, in his judgment, did not adequately characterize the material's performance. Union Carbide has contended that the non-submitted data may have been invalid because of experimental error, uncompleted tests, or other reasons.

100 °F, and (2) the pipe samples had lower performance in 73 °F sustained pressure tests than similar plastic piping materials already in use in the company's gas system.

In 1971, Union Carbide acknowledged to a pipe manufacturer that piping material manufactured by DuPont had a higher pressure rating at 100 °F than did its own DHDA 2077 Tan. Union Carbide laboratory notebooks examined by the Safety Board showed test results for the DHDA 2077 Tan material that generally met the 1,000-hour sustained pressure test value at both 100 °F and 73 °F, although, in the case of the 100 °F test, not by a wide margin. The notebooks also showed that the material had an early ductile-to-brittle transition point in stress rupture tests.[57]

Information Dissemination Within the Gas Industry

The OPS reports that more than 1,200 gas distribution or master meter system[58] pipeline operators submit reports to the OPS. Additionally, more than 9,000 gas distribution or master meter system pipeline operators are subject to oversight by the States.

As noted earlier, a frequent failure mechanism with polyethylene piping involves crack initiation and slow crack growth. These brittle-like fractures occur at points of stress intensification generated by external loading acting in concert with internal pressure and residual stresses.[59]

A 1985 paper[60] analyzed, for linear (straight line) behavior up to 100,000 hours, the stress rupture test performance (by elevated-temperature testing) of six polyethylene piping materials. The results were then correlated with field performance. This paper found that those materials that did not maintain linearity through 100,000 hours had what the author characterized as "known poor" or "questionable" field performance. On the other hand, those materials that maintained linearity through 100,000 hours had what the author characterized as "known good" field performance through their 20-year history logged as of 1985.

By the early to mid-1980s, the industry had developed a method to mathematically relate failure times to temperatures and stresses during stress rupture testing.[61] In the early 1990s, the industry developed "shift functions," another mathematical method to relate failure times to temperatures and stresses.[62]

One study[63] pointed out that using mathematical methods to calculate the remaining service life of pipe under the assumption that the pipe would only be exposed

[57]The data from the laboratory notebooks suggest that this material's early ductile-to-brittle transition would not have met today's standards.

[58]*Master meter system* refers to a pipeline system that distributes gas to a definable area, such as a mobile home park, a housing project, or an apartment complex, where the master meter operator purchases gas for resale to the ultimate consumer.

[59]Kanninen, M. F., O'Donoghue, P. E., Popelar, C. F., Popelar, C. H., Kenner, V. H., *Brief Guide for the Use of the Slow Crack Growth Test for Modeling and Predicting the Long-Term Performance of Polyethylene Gas Pipes*, Gas Research Institute Report 93/0105, February 1993. Because, after extrusion, the outside of the pipe cools before the inside, residual stresses are usually developed in the wall of the pipe.

[60]Mruk, S. A., "Validating the Hydrostatic Design Basis of PE Piping Materials."

[61]Bragaw, C. G., "Prediction of Service Life of Polyethylene Gas Piping System," *Proceedings Seventh Plastic Fuel Gas Pipe Symposium*, pp. 20-24, 1980, and Bragaw, C. G., "Service Rating of Polyethylene Piping Systems by the Rate Process Method," *Proceedings Eighth Plastic Fuel Gas Pipe Symposium*, pp. 40-47, 1983, and Palermo, E. F., "Rate Process Method as a Practical Approach to a Quality Control Method for Polyethylene Pipe," *Proceedings Eighth Plastic Fuel Gas Pipe Symposium*, pp. 96-101, 1983, and Mruk, S. A., "Validating the Hydrostatic Design Basis of PE Piping Materials," and Palermo, E. F., "Rate Process Method Concepts Applied to Hydrostatically Rating Polyethylene Pipe," *Proceedings Ninth Plastic Fuel Gas Pipe Symposium*, pp. 215-240, 1985.

[62]Popelar, C. H., "A Comparison of the Rate Process Method and the Bidirectional Shifting Method," *Proceedings of the Thirteenth International Plastic Fuel Gas Pipe Symposium*, pp. 151-161, and Henrich, R. C., "Shift Functions," *1992 Operating Section Proceedings*, American Gas Association.

[63]Broutman, L. J., Bartelt, L. A., Duvall, D. E., Edwards, D. B., Nylander, L. R., Stellmack-Yonan, M., *Aging of Plastic Pipe Used for Gas Distribution, Final Report*, Gas Research Institute report number GRI-88/0285, December 1988.

to stresses of internal operating pressures would result in unrealistically long service-life predictions. As noted earlier, polyethylene piping systems have failed at points of long-term stress intensification caused by external loading acting in concert with internal pressure and residual stresses; thus, to obtain a realistic prediction of useful service life, stresses from external loadings need to be acknowledged.

Over a number of years, the Gas Research Institute (GRI) sponsored research projects investigating various tests and performance characteristics of polyethylene piping materials. Among these projects was a series of research investigations directed at exploring the fracture mechanics principles behind crack initiation and slow crack growth. These investigations led to the development of slow crack growth tests. The research studies frequently identified the piping and resins studied by codes rather than by specific materials, manufacturers, or dates of manufacture.

In 1984, the GRI published a study[64] that compared and ranked several commercially extruded polyethylene piping materials produced after 1971. Again, the materials tested were identified by codes. Stress rupture tests were performed using methane and nitrogen as the internal pressure medium and air as the outside environment. Several stress rupture curves showed early transitioning from ductile to brittle failure modes.

The A.G.A.'s Plastic Materials Committee periodically updates the *A.G.A Plastic Pipe Manual for Gas Service*, which addresses a number of issues covered by this Safety Board special investigation. In 1991, the committee formed a task group to gather and then disseminate to the industry information regarding the performance of older plastic piping systems. The task group disbanded in 1994 without issuing a report.

In 1982 and 1986, DuPont formally notified its customers about brittle-like cracking concerns with the company's pre-1973 pipe. Safety Board investigators could find no record of either Century/Amdevco, Union Carbide, or any other piping or resin manufacturer formally notifying the gas industry of the susceptibility to premature brittle-like failures of their products. Nor does any mechanism exist to ensure that the OPS receives safety-related information from manufacturers.

Regarding Federal actions on this issue, the OPS has not informed the Safety Board of any substantive action it has taken to advise gas system operators of the susceptibility to premature brittle-like failures of any older polyethylene piping.[65]

Installation Standards and Practices

The discussion in this section is intended to present a "snapshot" of the regulations and some of the primary standards, practices, and guidance to prevent stress intensification at plastic service connections to steel tapping tees. The appendix to this report includes a description of the connection in the Waterloo accident, and figure 10 provides a close-up view of the failed fitting.

Federal Regulations -- The OPS establishes, in 49 CFR 192.361, minimum pipeline safety standards for the installation of gas service piping.

Paragraph 192.361(b) reads as follows:

> *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil....

Paragraph 192.361(d) reads:

> *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

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[64]Cassady, M. J., Uralil, F. S., Lustiger, A., Hulbert, L. E., *Properties of Polyethylene Gas Piping Materials Topical Report (January 1973 - December 1983)*, GRI Report 84/0169, Gas Research Institute, Chicago, IL, 1984.

[65]The Safety Board asked the OPS for information about its actions in regard to older piping, after which, in 1997, the OPS notified State pipeline safety program managers of several issues regarding Century pipe and solicited input on their experiences with this particular piping.

Figure 10 -- Close-up view of failed plastic pipe connection to steel tapping tee from site of Waterloo, Iowa, accident. A portion of the fractured plastic service line (light-colored material) remains attached to the tee.

Subsequent to the Waterloo accident, personnel from the Iowa Department of Commerce, after discussions with OPS personnel, stated that the Waterloo installation was not in violation of the Federal regulation. They further stated that, while they agree that the installation of protective sleeves[66] at pipeline connections is prudent, a specific requirement to install protective sleeves is beyond the scope of Part 192 and is inconsistent with the regulation's performance orientation.

The Transportation Safety Institute (TSI), part of RSPA, conducts training classes for Federal and State pipeline inspectors. TSI instructors advise class participants that many of the performance-oriented regulations within Part 192 can only be found to be violated if the gas system fails in a way that demonstrates that the regulation was not followed. The TSI acknowledges the difficulty of identifying violations under paragraph 192.361(d). A TSI instructor told the Safety Board that, in the case of the failed pipe at Waterloo, an enforcement action faulting the installation would be unlikely to prevail because of the poor brittle-like crack resistance of the failed pipe and the length of time (23 years) between the installation and failure dates.

GPTC Guide for Gas Transmission and Distribution Piping Systems -- After the adoption of the Natural Gas Pipeline Safety Act in August 1968, the American Society of Mechanical Engineers, after discussions with

[66]Protective sleeves are intended to help shield the pipe at the connection point from bearing loads and shear forces and to limit the maximum pipe bending.

the Secretary of Transportation, formed the Gas Piping Standards Committee (later renamed the Gas Piping Technology Committee) to develop and publish "how-to" specifications for complying with Federal gas pipeline safety regulations. The result was the *GPTC Guide for Gas Transmission and Distribution Piping Systems* (GPTC Guide). The GPTC Guide lists the regulations by section number and provides guidance, as appropriate, for each section of the regulation.

In its investigation of the previously referenced 1971 accident in Texas, the Safety Board determined that protective sleeves were too short to fully protect a series of service connections to a main. The Safety Board noted that a protective sleeve must have the correct inner diameter and length if it is to protect the connection from excessive shear forces. As a result, and in response to a Safety Board safety recommendation,[67] the 1974 and later editions of the GPTC Guide included guidance that "a protective sleeve designed for the specific type of connection should be used to reduce stress concentrations." No guidance was included as to the importance of a protective sleeve's length, diameter, or placement.[68]

The GPTC Guide does not include recommendations to limit bending in plastic piping during the installation of service lines under 49 CFR 192.361. Although the guide references the *A.G.A. Plastic Pipe Manual for Gas Service*, and this manual does provide recommendations on bending limits, the GPTC Guide does not reference this manual in its guidance material under 49 CFR 192.361.

A.G.A. Plastic Pipe Manual for Gas Service -- The most recent edition of the *A.G.A. Plastic Pipe Manual for Gas Service*[69] identifies the connection of plastic pipe to service tees as "a critical junction" needing installation measures "to avoid the potentially high…stresses on the plastic at this point." The manual recommends proper support and the use of protective sleeves. Although the manual recommends following manufacturers' recommendations, no guidance is included on the importance of a protective sleeve's proper length, diameter, or placement. The manual includes, without elaboration, the following sentence:

> Installation of the tee outlet at angles up to 45° from the vertical or along the axis of the main as a 'side saddle' or 'swing joint' may be considered to further minimize…stresses.

The 1994 edition adds that manufacturers' recommended limits on bending at fittings may be more restrictive than for a run of piping alone.

A.G.A. Gas Engineering and Operating Practices (GEOP) Series -- The preface to the current *Distribution Book D-2* of the GEOP series states that the intent of the books is to offer broad general treatment of their subjects, and that listed references provide additional detailed information.

Figure 11 reproduces an illustration from *Book D-2.* This figure shows a steel tapping tee with a compression coupling joint connected to a plastic service. The illustration shows a protective sleeve and includes a note to extend the protective sleeve to undisturbed or compacted soil or to blocking. But the figure also shows the blocking positioned so that either the edge of the blocking or the edge of the protective sleeve might provide a fixed contact point on the plastic service pipe if the weight of backfill were to cause the pipe to bend down. Additional illustrations within this GEOP series book show this same positioning of the blocking with respect to the plastic pipe.

ASTM -- The most recent ASTM standard covering the installation of polyethylene piping was revised in 1994.[70] This standard addresses

[67]Safety Recommendation P-72-64 from National Transportation Safety Board Pipeline Accident Report-- *Lone Star Gas Company, Fort Worth, Texas, October 4, 1971.*

[68]The correct positioning of the protective sleeve has a bearing on its effective length.

[69]*A.G.A. Plastic Pipe Manual for Gas Service*, American Gas Association, Catalog No. XR 9401, 1994.

[70]ASTM D2774-94, *Standard Practice for Underground Installation of Thermoplastic Pressure Piping*, American Society for Testing and Materials, 1994.

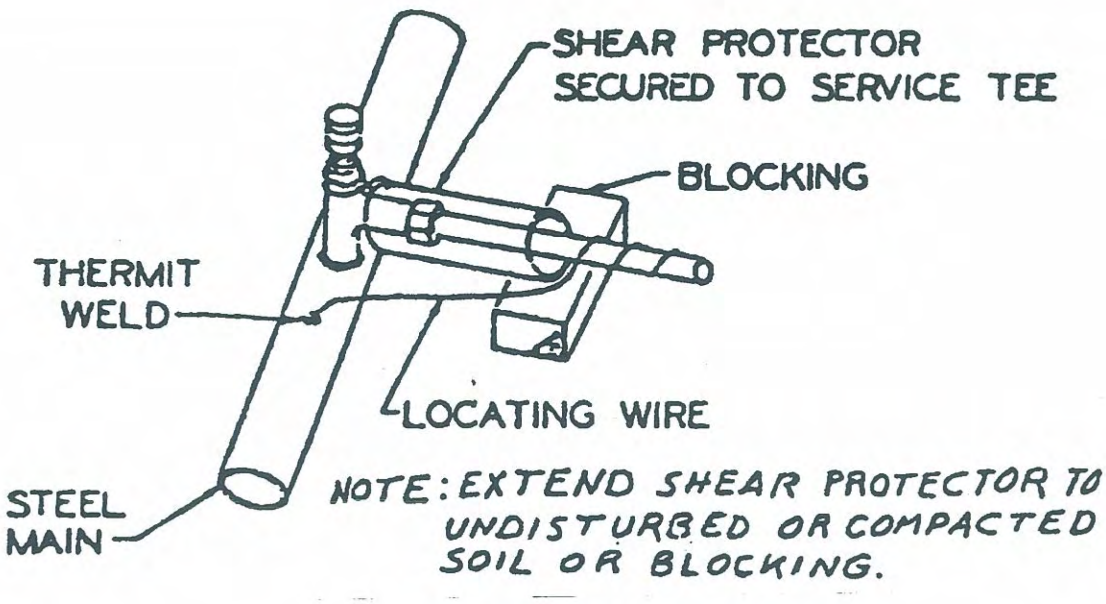

Figure 11 -- Reproduction from A.G.A. GEOP series illustrating application of protective sleeve. (Hand-scribed notation from the original.)

the vulnerability of the point-of-service connection to the main.

This standard, advising consultation with manufacturers, recommends taking extra care during bedding and backfilling to provide for firm and uniform support at the point of connection. In addition, the document recommends minimizing bends near tap connections, generally recommending that bends occur no closer than 10 pipe diameters from any fitting and that manufacturers' bend limits be followed. Similar recommendations for avoiding bends close to a fitting can be found in the forward to a water industry standard.[71]

This ASTM standard further recommends the use of a protective sleeve if needed to protect against possible differential settlement. Currently, manufacturers that provide protective sleeves have their own criteria for designing sleeve lengths and diameters for their fittings. Some manufacturers' criteria are based on limiting stress to a maximum safe value,[72] while one manufacturer has advised the Safety Board that its sleeve is not designed to limit bending, but only to guard against shear forces at the connection point.

Guidance Manual for Operators of Small Natural Gas Systems -- The OPS/RSPA *Guidance Manual for Operators of Small Natural Gas Systems* notes that plastic pipe failures have been found at transitions between plastic and metal pipes at mechanical fittings. The manual states the need to firmly compact soil under plastic pipe, advises following manufacturers' instructions for proper coupling procedures, and shows protective sleeves on connections of plastic services to steel tapping tees. The manual indicates that a properly designed protective sleeve should be used. The manual does not caution against bending the piping in proximity to a connection.

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[71]Forward to American Water Works Association Standard C901-96, *AWWA Standard for Polyethylene (PE) and Tubing, ½ In. (13 mm) Through 3 In. (76 mm) for Water Service*, effective March 1, 1997.

[72]Allman, W. B., "Determination of Stresses and Structural Performance in Polyethylene Gas Pipe and Socket Fittings Due to Internal Pressure and External Soil Loads," *1975 Operating Section Proceedings*, American Gas Association, 1975.

Manufacturers' Recommendations -- As noted earlier, both the *A.G.A. Plastic Pipe Manual for Gas Service* and ASTM D2774 specifically refer the reader to manufacturers for further guidance on limiting shear and bending forces at plastic service connections made to steel mains via steel tapping tees.

Bending and Shear Forces -- Safety Board investigators contacted representatives of the four principal companies that marketed plastic piping for gas service to determine to what extent plastic piping manufacturers were providing recommendations for limiting shear and bending forces at plastic service connections to steel mains via steel tapping tees. The four manufacturers contacted were CSR PolyPipe, Phillips Driscopipe, Plexco, and Uponor Aldyl Company (Uponor).

Three out of four of these manufacturers had published recommendations addressing these issues. These three manufacturers have historically emphasized heat fusion fitting systems[73] instead of field-assembled mechanical fitting systems. Representatives of these manufacturers indicated that mechanical fittings manufacturers should provide installation instructions covering their systems. Accordingly, one of the manufacturers' published literature referred the reader to the manufacturers of mechanical fittings for installation instructions. Nonetheless, these three major polyethylene pipe manufacturers did, in fact, provide recommendations to limit shear and bending forces, and these recommendations can apply to plastic service connections to steel mains via steel tapping tees.

With respect to the specific issue of limiting bends, DuPont, in January 1970, issued recommendations to limit bends for polyethylene pipe. DuPont/Uponor[74] later published bend radius recommendations that differentiated between pipe segments consisting of pipe alone and those with fusion fittings. The recommendations specified much less bending for pipe segments with fusion fittings; however, DuPont/Uponor did not provide bend limits for mechanical fittings. Two of the other major manufacturers (Phillips Driscopipe and Plexco) provide bend limits and differentiate between pipe alone and pipe with fittings, without specifying the type of fittings. None of the manufacturers' literature discusses bending with or against any residual bend remaining in the pipe after it is uncoiled. (See "Pipe Residual Bending" below.)

Of these four major polyethylene gas pipe manufacturers, only CSR PolyPipe had no published recommendations for limiting shear and bending forces at plastic service connections to steel mains via steel tapping tees. Although the company does not manufacture steel tapping tees with compression ends for attachment to plastic services, it does manufacture pipe that will be attached to steel tapping tees via mechanical compression couplings. The company has been supplying polyethylene pipe to the gas industry since the 1980s[75] and is thus relatively new to that business compared to the other three major manufacturers. When CSR PolyPipe entered the market, plastic materials were vastly improved compared to earlier versions with respect to resistance to crack initiation and slow crack growth. For this reason, according to CSR PolyPipe personnel, the company saw less need to publish installation recommendations.

The Safety Board attempted to identify every U.S. steel tee manufacturer that currently manufactures steel tees with a compression end for plastic gas service connections.[76] The Safety Board identified and contacted representatives of Continental Industries (Continental), Dresser Industries, Inc. (Dresser), Inner-Tite Corp. (Inner-Tite),[77] and Mueller Company (Mueller).

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[73]Heat fusion fittings are used to make piping joints by heating the mating surfaces and pressing them together so that they become essentially one piece.

[74]Uponor purchased DuPont's plastic pipe business in 1991.

[75]CSR Hydro Conduit Company purchased PolyPipe in 1995. PolyPipe began supplying polyethylene pipe to the gas industry in the 1980s.

[76]J. B. Rombach, Inc., which manufactures M. B. Skinner Pipeline products, told the Safety Board that it no longer manufactures or markets its "Punch-It-Tee" line of steel tapping tees. Chicago Fittings Corporation told the Safety Board it no longer manufactures or markets its line of steel tapping tees. The Safety Board therefore made no further inquiry with these companies.

[77]Inner-Tite did not manufacture steel tees; it purchased them, affixed its own compression connections,

Only Continental and Inner-Tite offered protective sleeves to their customers as an option. None of these manufacturers has published installation recommendations to limit shear and bending forces on the plastic pipe that connects to their steel tapping tees.

On another issue related to protective sleeves, Safety Board examination of a protective sleeve offered by Continental to its customers revealed that the sleeve that did not have sufficient clearance to allow the application of field wrap (intended to protect the steel tee from corrosion after it is in the ground) to that portion of the steel tee under the sleeve. This observation was confirmed by a Continental representative.

Pipe Residual Bending -- The service involved in the Waterloo accident was installed with a bend at the connection point to the main. (See illustration in appendix A.) The plastic service pipe leaving the tee immediately curved horizontally. The pipe was cut out and brought into the laboratory, at which time the bend had a measured horizontal radius of approximately 34 inches. Based on field conditions and photos, MidAmerican Energy estimated the original installed horizontal bend radius to have been about 32 inches. This bend is sharper than that allowed by current industry installation recommendations for modern piping adjacent to fittings.

An issue related to recommended bend radius is residual pipe bending. Plastic pipe often arrives at a job site in banded coils. After the bands are released, the coiled pipe will partially straighten, but some residual bending will remain. The water industry already recognizes that bends *in* the direction of the residual coil bend should be treated differently than bends *against* the direction of the bend;[78] however, gas industry field bend radius recommendations do not address residual coil bending.

A former Iowa Public Service Company employee stated that Iowa Public Service Company, in an effort to reduce stress at connection points, generally attempted to install polyethylene services at an angle to the main to match the residual bend left after uncoiling the pipe. This former employee stated that no set time was specified to allow for complete relaxing of the pipe, but that the pipe would be placed in the ditch, and the crews would weld the tee at what they judged to be the appropriate angle.

MidAmerican Energy Installation Standards -- As a result of the Waterloo accident, Safety Board investigators examined some of MidAmerican Energy's construction standards for minimizing shear and bending forces at plastic service connection points to steel mains. Specifically, Safety Board investigators examined MidAmerican Energy's standards pertaining to providing firm support, using protective sleeves, and limiting bends at plastic service connections to steel mains.

According to the company, MidAmerican Energy no longer installed steel tapping tees with mechanical compression ends to connect to plastic service pipe. Instead, it employed steel tapping tees welded at the factory to factory-made steel-to-plastic transition fittings. It then field-fused the plastic ends from the transition fittings to the plastic service pipe.

MidAmerican Energy advised the Safety Board that it had no standard calling for firm compacted support under plastic service connection points to steel mains.

MidAmerican Energy designed, constructed, and installed its own protective sleeves for installation on its purchased steel tapping tee/transition fitting assemblies. MidAmerican Energy required its protective sleeves to be a minimum of 12 inches long; however, MidAmerican Energy could provide no design criteria for this length. MidAmerican Energy has reported that the company's unwritten field practice was to install the smallest diameter sleeve that will clear the field wrapped fitting, but MidAmerican Energy had no written requirements or design criteria for the diameter of its protective sleeves. The company's standard showed the sleeve as approximately centered over the steel-to-plastic transition, and no

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and marketed the complete assembly.

[78]Forward to American Water Works Association Standard C901-96.

criteria or instructions were provided for the correct positioning of the sleeves.

The Safety Board notes that manufacturers that provide factory-made steel-to-plastic transition fittings will also provide protective sleeves along with the transition fittings and will provide positioning guidance for their use.

Effective January 27, 1997, MidAmerican Energy instituted minimum bend radii requirements that differentiated between pipe segments consisting of pipe alone and pipe with fittings.

Gas System Performance Monitoring

This section examines gas system performance monitoring largely in the context of the Waterloo accident.

Federal regulations (49 CFR 192.613 and 192.617) require that gas pipeline system operators have procedures in place for monitoring the performance of their gas systems. These procedures must cover surveillance of gas system failures and leakage history, analysis of failures, submission of failed samples for laboratory examination (to determine the causes of failure), and minimizing the possibility of failure recurrences.

Prior to the Waterloo accident, Midwest Gas had two systems for tracking, identifying, and statistically characterizing failures. The first system was the leak data base, which tracked the status of leak reports, documented actions taken, and recorded almost all gas system leaks. The data base received input from two primary sources: leak reports from customers and leak survey results. The data base parameters classified the general type of piping material that leaked (such as "plastic," "cast iron," "bare steel"), and indicated whether the leak occurred in pipe or certain fittings. The parameters did not include manufacturers, manufacturing or installation dates, sizes,[79] or failure conditions commonly found with plastic piping (for example, poor fusions, bending force failures, insufficient soil compaction, rock impingement failures, and lack or improper use of protective sleeves). The data base indicated that the performance of plastic piping overall was comparable to other piping materials. MidAmerican Energy stated that the parameters chosen for this data base were those required for reporting to the DOT. The company said the parameters were also chosen on the premise that pipe meeting industry specifications would perform similarly.

The second system used by Midwest Gas for tracking failures was the company's material failure report data base, which was intended for use in evaluating the quality and performance histories of products installed in the company's gas system. Input to the data base was by way of a form (or, in some cases, a tag) filled out by field personnel. The form included categories such as the manufacturer, size, and an internal material identification number of the affected pipe or component. It also included areas for a narrative description of the failure. The form did not include dates of manufacture or installation dates or failure conditions commonly found on plastic piping. Field personnel sent the failed item, along with the completed form or tag, to engineering personnel, who examined the item and accompanying information to determine the need for corrections. Midwest Gas personnel then transcribed the narrative description of the failure word-for-word into the data base without attempting to determine and categorize causes of failure. Engineering personnel compiled the available data into periodically issued material summary reports. The company said engineering personnel from time to time sorted available data fields to determine trends.

The material failure report data base included only a portion of the leaks in the Midwest Gas system. For example, if Midwest Gas field personnel corrected a leak by replacing an entire line segment without digging up the leaking component (which the company said was a frequent occurrence with bare steel, cast iron, and certain plastic piping that was difficult to join), the material failure report data base system was not used. Also, field personnel were not required to use the reporting system if they determined that the failed item was related to an operating problem, such as excavation damage, rather than to a material problem.

[79]While sizes of the piping, along with a drawing of the piping assembly, were normally written or drawn on the forms, piping size was not captured in the data base generated by these forms.

Additionally, the company indicated that the system did not enjoy full participation from field personnel.

When, after the Waterloo accident, Midwest Gas attempted to determine if installations with Century plastic piping had higher rates of failure than those with piping from other manufacturers, it found that its material failure report data base's incomplete coverage of gas leaks made that data base unsuitable for the purpose. The company decided instead to use the leak data base, which the company believed included almost all leaks. But because the leak data base did not list the manufacturers of plastic piping, Midwest Gas took several months to correlate entries in the leak data base with records showing the manufacturers of plastic piping. Midwest Gas, in 1995, concluded that piping installations with Century piping had failure incidence rates that were significantly higher than the balance of its plastic piping system. The company did not correlate entries with the years of installation.

Since the Waterloo accident, the current Waterloo gas system operator, MidAmerican Energy, in addition to replacing all its Century pipe, has added parameters such as piping size, installation date, and pressure to the forms used for input into its leak data base. Also since the accident, MidAmerican Energy has added parameters such as installation date, pressure, and component location and position to its form for input into its material failure report data base. The company has also worked to determine if any other plastic piping manufacturers can be linked to piping with unacceptable performance.

The current (1994) edition of the *A.G.A. Plastic Pipe Manual for Gas Service* recommends the use and provides a sample of a form for recording information on plastic piping failures. The manual recommends collecting this information and then performing a visual examination or, in some cases, a laboratory analysis, to determine the type and cause of failure.

ANALYSIS

General

The common thread in a series of plastic pipeline accidents investigated by the Safety Board and others since the early 1970s—as well as in a number of reports of other, non-accident, plastic pipeline leaks—is the indicated presence of brittle-like cracking leading to eventual pipe failure. The number and similarity of these brittle-like failures seem to indicate that the long-term durability of plastic piping, which was premised on the pipe's ductility, may have been overstated by the method used to rate the long-term strength of plastic piping materials.

Based on the available evidence, any public safety threat posed by possible premature failure of plastic piping appears to be limited to locations where stress intensification exists. This special investigation examines in detail one installation configuration—plastic pipe mechanical connections to steel mains via steel tapping tees—where great potential exists for the generation of stress intensification. At these connections, certain poor installation practices have been known to create stress that is greater than the pipe can withstand. Thus, inadequate or improper installation of piping connections, in combination with brittle piping, represents one identifiable public safety hazard associated with the thousands of miles of older plastic piping now in service nationwide.

Gas system operators need to have an effective surveillance and data analysis (performance monitoring) program to determine the extent of the possible hazard associated with their pipeline systems, including plastic piping. Such a program must be adequate to detect trends as well as to identify localized problem areas, and it must be able to relate poor performance to specific factors such as plastic piping brands, dates of manufacture (or installation dates), and failure conditions.

The major safety issues developed during this special investigation are as follows:

- The vulnerability of plastic piping to premature failures due to brittle-like cracking;
- The adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains; and
- Performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems.

The remainder of this analysis addresses each of these major safety issues, as well as a number of other issues affecting the safety of plastic piping for gas service.

Durability of Century Utility Products Piping

Iowa Public Service Company, the company that installed the Century pipe involved in the 1994 Waterloo, Iowa, pipeline accident, began purchasing all of its plastic pipe from Century in 1970, when Amdevco/Century had just started to manufacture plastic pipe. These purchases were made without Iowa Public Service Company's having a testing or technical evaluation program and without Century/Amdevco having a successful track record. Iowa Public Service Company decided on the Century product because Century offered favorable commercial terms for a product it claimed was virtually identical to the DuPont plastic piping that had previously been used.

The Safety Board has investigated two other pipeline accidents, one in Nebraska in 1978 and one in Minnesota in 1983, that involved Century piping. The Safety Board is also aware of four other accidents that it did not investigate that involved the same brand of piping. Moreover, laboratory testing of Century product samples from the Waterloo accident determined that the material had the same brittle-like crack properties that have been associated with materials having poor performance histories.

Laboratory examination also revealed evidence of slow crack growth typical of brittle-like cracking.

The Century pipe involved in the Waterloo accident was made from Union Carbide's DHDA 2077 Tan resin. Although Union Carbide's laboratory data indicated that the material had the strength required by existing government and industry requirements, the Safety Board's review of the same data showed that the material had an early ductile-to-brittle transition, indicating poor resistance to brittle-like fractures.

In the early 1970s, a Minnesota gas system operator tested a number of piping products made from DHDA 2077 Tan resin, including those marketed by Century, as part of its comprehensive specification, testing, and evaluation program. The company rejected piping made from the Union Carbide product for use in its system based on the results of sustained pressure tests. Union Carbide, in 1971, acknowledged that its DHDA 2077 Tan resin material had a lower pressure rating at 100 °F than did DuPont's polyethylene pipe material.

Midwest Gas, the Waterloo, Iowa, gas operator at the time of the explosion and fire, had experienced at least three other significant failures involving Century pipe. The most recent failures, occurring between 1992 and 1994, prompted the company to collect samples of the Century material for independent laboratory testing. Samples were being gathered for testing at the time of the Waterloo accident. The subsequent laboratory report indicated that the Century piping had poor resistance to slow crack growth.

Midwest Gas's subsequent analysis of the company's leakage history concluded that its installations with Century piping had failure rates significantly higher than those with piping from other manufacturers. Midwest Gas had received warnings from two pipe fitting manufacturers against use of their products with Century pipe because of Century pipe's susceptibility to brittle-like cracking. The current operating company in the Waterloo, Iowa, area, MidAmerican Energy, has, since the accident, replaced all the identified Century piping in its gas pipeline system.

The Safety Board concludes that plastic pipe extruded by Century Utility Products, Inc., and made from Union Carbide's DHDA 2077 Tan resin has poor resistance to brittle-like cracking under stress intensification, and this characteristic contributed to the Waterloo, Iowa, accident.

The Safety Board believes that RSPA should notify pipeline system operators who have installed polyethylene gas piping extruded by Century Utility Products, Inc., from Union Carbide Corporation DHDA 2077 Tan resin of the piping's poor brittle-crack resistance. The Safety Board further believes that RSPA should require these operators to develop a plan to closely monitor the performance of this piping and to identify and replace, in a timely manner, any of the piping that indicates poor performance based on such evaluation factors as installation, operating, and environmental conditions; piping failure characteristics; and leak history.

Strength Downturn and Brittle Characteristics

While Century piping has been identified specifically as being subject to brittle-like cracking (slow crack growth), evidence suggests that much of the early polyethylene piping, depending on the brands, may be more susceptible to such cracking than originally thought and thus may also be subject to premature failure.

The principal process used in the United States to rate the strength of plastic piping materials has been, and remains, the procedure this report has referred to as the PPI procedure. The PPI procedure, which was developed in the early 1960s, involved subjecting test piping to different stress values and recording how much time elapsed before the piping ruptured. The resulting data were then plotted, and a best-fit straight line was derived to represent the material's decline in rupture resistance as its time under stress increased.

To meet the requirements of the PPI procedure, at least one tested sample had to be able to withstand some level of hoop stress without rupturing for at least 10,000 hours, or slightly more than 1 year. The straight line plotted describing the data for this material was extrapolated out by a factor of 10, to 100,000 hours (about 11 years). The point at which the sloping straight line intersected the 100,000-hour point indicated the appropriate hydrostatic design basis for this material.

A key assumption characterized the assignment of a hydrostatic design basis under the PPI procedure: The procedure assumed that the gradual decline in the strength of plastic piping material as it was subjected to stress over time would always be described by a straight line. In the early 1960s, the industry had had little long-term experience with plastic piping, and a straight line seemed to represent the response of the material to laboratory stress testing. With little other information on which to base strength estimations, the straight-line assumption appeared valid.

As experience grew with plastic piping materials and as better testing methods were developed, however, the straight-line assumptions of the PPI procedure came to be challenged. Elevated-temperature testing indicated that polyethylene piping can exhibit a decline in strength that does not follow a straight line path but instead describes a downturn, as shown in figure 9. The difference between the actual (falloff) and projected (straight line) strengths became even more pronounced as the lines were extrapolated beyond 100,000 hours. The timing and slope of the downturn varied by pipe formulation and manufacturer.

Piping manufacturers addressed this issue by improving their formulations to delay onset of the downturn in strength. At the same time, the PPI procedure was improved to reflect the fact that elevated-temperature testing, by accelerating the fracture process, provided a good representation of the true long-term strength of the tested material at 73 °F. By 1986, the PPI adopted a requirement to exclude any materials that deviated from the straight-line path to at least 100,000 hours at 73 °F.

The combination of more durable modern plastic piping materials and more realistic strength testing has rendered the strength ratings of modern plastic piping much more reliable. Unfortunately, much of the early plastic piping was sold and installed with expectations of strength and long-term performance that, because they were based on questionable assumptions about long-term performance, may not have been valid. This is borne out by data from a variety of sources. The history of strength rating requirements, a review of the piping properties and literature, and observations of several experts with extensive experience in plastic piping, all suggest that much of the polyethylene pipe, depending upon the brands, manufactured from the 1960s through the early 1980s fails at lower stresses and after less time than originally projected. The Safety Board therefore concludes that the procedure used in the United States to rate the strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.

Another important assumption of the design protocol for plastic pipe involved the ductility of the materials. It was assumed, based on short-term tests, that plastic piping had long-term ductile properties. Ductile material, by bending, expanding, or flexing, can redistribute stress concentrations better than can brittle material, such as cast iron. Notable from results of tests performed under the PPI procedure was that those short-term stress ruptures in the testing process tended to be characterized by substantial material deformation in the area of the rupture. This deformation described a material with obvious ductile properties. Under prolonged testing, however, as time-to-failure increased, some stress ruptures in some materials occurred as slit failures that, because they were not accompanied by substantial deformation, were more typical of brittle-like failures. These slit or brittle-like failures were characterized by crack initiation and slow crack growth. The PPI procedure did not distinguish between ductile fractures and slit fractures and assumed that both failures would be described by the same straight line.

The assumption of ductility of plastic piping had important safety ramifications. For example, a number of experts believed it was safe to design plastic piping installations based on stresses primarily generated by internal pressure and to give less consideration to stress intensification generated by external loading. Ductile material reduces stress intensification by localized yielding, or deformation.

As noted previously, laboratory data supported the strength rating assigned to DHDA 2077 Tan resin by the process used at the time to rate strength; nevertheless, the material showed evidence of early ductile-to-brittle transition. The fact that the process used to measure the long-term durability of piping materials did not reveal the premature susceptibility to brittle-like cracking of the DHDA 2077 Tan material highlights the weaknesses of the process in use at the time. More significantly, it calls into question the durability of other early materials that were rated using the same process and that remain in service today. This concern is heightened by the fact that, in addition to the Waterloo accident involving Century pipe and DHDA 2077 Tan resin, numerous other accidents investigated or documented by the Safety Board have suggested that brittle-like cracking occurs in older plastic piping at significant rates.

Stress intensification has been an element common to many plastic gas pipeline accidents investigated by the Safety Board. The premature transition of plastic piping from ductile failures to brittle failures appears to have little observable adverse impact on the serviceability of plastic piping except in those instances in which the piping is subjected to external stresses. Rock impingement, soil settlement, and excess pipe bending are among the potential sources of stress intensification, and the combination of brittle piping and external stresses can lead to significant rates of failures. These failures can, in turn, lead to serious accidents. The Safety Board therefore concludes that much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s may be susceptible to premature brittle-like failures when subjected to stress intensification, and these failures represent a potential public safety hazard.

The Safety Board believes that RSPA should determine the extent of the susceptibility to premature brittle-like cracking of older plastic piping (beyond that piping marketed by Century Utility Products, Inc.) that remains in use for gas service nationwide. RSPA should then inform gas system operators of the findings and require them to closely monitor the performance of the older plastic piping and to identify and replace, in a timely manner, any of the piping that indicates poor performance based on such evaluation factors as installation, operating, and environmental conditions; piping failure characteristics; and leak history. Because materials other than polyethylene have been used in plastic pipe for gas service, and even though the Safety Board has not examined those materials in depth, RSPA would do well to address those other plastic piping materials still in gas service.

The Safety Board further believes that RSPA should immediately notify those States and territories with gas pipeline safety programs of the susceptibility to premature brittle-like cracking of much of the plastic piping manufactured from the1960s through the early 1980s and of the actions that RSPA will require of gas system operators to monitor and replace piping that indicates unacceptable performance.

Information Dissemination Within the Gas Industry

As noted earlier, much of the polyethylene pipe, depending upon the brands, from the 1960s through the early 1980s may be susceptible to premature brittle-like failures when subjected to stress intensification. Poor resistance to crack initiation and slow crack growth in the face of stress intensification can translate into a higher incidence of leaks and a decrease in public safety.

Premature brittle-like cracking in plastic piping is a complex phenomenon. Those pipelines operators who wish to study the phenomenon can gain a basic understanding of brittle-like cracking by researching the technical literature, but without direct and straightforward communication to pipeline operators about brands of piping and conditions that increase the likelihood of brittle cracking, many pipeline operators may not have the knowledge to make good decisions affecting public safety. Some of these key decisions include how often to conduct leak surveys and whether to repair or replace portions of pipeline systems.

Frequently, piping manufacturers, because they can receive feedback from a number of customers, are the first to learn of systemic problems with their products. For small operators, contact with a manufacturer may be the major source of outside communication about poorly performing products. Unfortunately, while manufacturers have a high degree of technical expertise regarding their products, they may also tend to aggressively publicize the best performance characteristics of their products while only reluctantly acknowledging weaknesses. The Safety Board is aware of only a very few cases in which manufacturers of resin or pipe have formally notified the gas industry of materials having poor resistance to brittle cracking.

Thus, although reputable manufacturers commonly provide essential technical assistance and serve as partners to pipeline operators, operators are still responsible for evaluating and determining which products are most likely to maintain the integrity of their pipeline systems. Furthermore, perhaps because the possibility of premature failure of plastic piping due to brittle-like cracking has not been fully appreciated within the industry and the scope of the potential problem has not been fully measured, the Federal Government has not provided information on this issue to gas system operators. The Safety Board concludes that gas pipeline operators have had insufficient notification that much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s may be susceptible to brittle-like cracking and therefore may not have implemented adequate pipeline surveillance and replacement programs for their older piping.

In the view of the Safety Board, manufacturers of resin and pipe should do more to notify pipeline operators about the poor brittle-crack resistance of some of their past products. The PPI is the manufacturers' organization that covers most of the major resin and pipe producers, many of whom have manufactured resin and pipe for several years. Although manufacturers of some of the worst performing materials and piping products may not have survived and therefore may not be current members of the PPI, the current members of the PPI have produced much, if not most, of the plastic piping and materials used in the manufacture of plastic piping over many years. The Safety Board therefore believes that the PPI should advise its members to notify pipeline system operators if any of their piping products, or materials used in the manufacture of piping products, currently in service for natural gas or other hazardous materials indicate poor resistance to brittle-like failure.

In the interest of public safety and in order for the Federal Government to fully exercise its oversight responsibilities, the Safety Board believes that RSPA should, in cooperation with the manufacturers of products used in the transportation of gases or liquids regulated by the OPS, develop a mechanism by which the OPS will receive copies of all safety-related notices, bulletins, and other communications regarding any defect, unintended deviation from design specification, or failure to meet expected performance of any piping or piping product that is now in use or that may be expected to be in use for the transport of hazardous materials.

Over a number of years, the GRI has developed a significant amount of data on older plastic piping, but it has published the data in codified terms. Without a way to associate codes with specific products, the average gas pipeline operator could not make effective use of the data. The Safety Board concludes that, even though the GRI has developed a significant amount of data about older plastic piping used for gas service, because the data have been published in codified terms, the information is not sufficiently useful to gas pipeline system operators. The Safety Board believes that the GRI should publish the codes used to identify plastic piping products in previous GRI studies to make the information contained in these studies more useful to pipeline system operators.

Installation Standards and Practices

Because of the large safety factor[80] used in the design equation, even many of the materials

[80]Technically, this term should be "design factor."

having early downturns in strength appear, absent stress intensification, to have the capacity to provide good service. Unfortunately, stress intensification, which can take many forms, has been found in a number of gas piping systems.

Almost all of the plastic pipeline accidents the Safety Board has investigated involving brittle-like cracking have been linked to stress intensification generated by external forces acting on the pipe. Examples of conditions that can generate stress intensification include differential earth settlement, particularly at connections with more rigidly anchored fittings; excessive bending as a result of installation configurations, especially at fittings; and point contact with rocks or other objects.

As discussed below, much of the guidance available to gas system operators for limiting stress intensification at plastic pipeline connections to steel mains is inadequate or ambiguous. It is particularly significant that none of the steel tapping tee manufacturers had published recommendations to safely limit shear and bending forces at connections where their products are used. Based on its review of this guidance and on the history of the plastic pipeline accidents it has investigated, the Safety Board concludes that, because guidance covering the installation of plastic piping is inadequate for limiting stress intensification at plastic service connections to steel mains, many of these connections may have been installed without adequate protection from shear and bending forces. The specific limitations of existing guidance are addressed in the sections that follow.

Federal Regulations -- RSPA acknowledges that the regulation that requires gas service lines to be installed so as to minimize anticipated piping strain and external loading lacks performance measurement criteria. The Safety Board pointed out in a previous accident investigation report[81] that, although the OPS considers many of its pipeline safety regulations to be performance-oriented requirements, many are no more than general statements of required actions that do not establish any criteria against which the adequacy of the actions taken can be evaluated. The Safety Board has further stated that regulations that do not contain measurable standards for performance make it difficult to determine compliance with the requirements. The Safety Board therefore previously recommended that RSPA:

> P-90-15
> Evaluate each of its pipeline safety regulations to identify those that do not contain explicit objectives and criteria against which accomplishment of the objective can be measured; to the extent practical, revise those that are so identified.

As a result of this safety recommendation, the OPS asked the National Association of Pipeline Safety Representatives liaison committee to review the 20 regulations deemed to be the least enforceable due to lack of clarity. The Safety Board has encouraged RSPA to make such a review a periodic effort so that all of the regulations, not just the specified 20, are continually clarified. The last correspondence to the Safety Board from the OPS regarding this recommendation was on March 8, 1993, and the recommendation has remained classified "Open--Acceptable Response." In an October 31, 1997, letter to the OPS, the Safety Board inquired as to the status of 28 open safety recommendations to RSPA, including P-90-15. The OPS has not yet provided a written response to the request for the status of P-90-15. The Safety Board will continue to follow the progress and urge completion of this recommendation. In the meantime, other elements of the gas pipeline industry can take steps to enhance the protection of vulnerable piping at connections, as outlined below.

A.G.A. Plastic Pipe Manual for Gas Service -- A protective sleeve helps to shield the pipe at the connection point from bearing loads and shear forces, and controls the maximum bending. The *A.G.A. Plastic Pipe Manual for Gas Service* recommends installing protective sleeves at connections of plastic pipe, but it does not directly address designing the sleeve to have the correct inner diameter and length, or the need to position the sleeve

[81] National Transportation Safety Board Pipeline Accident Report--*Kansas Power and Light Company Natural Gas Pipeline Accidents, September 16, 1988, to March 29, 1989* (NTSB/PAR-90/03).

properly. Instead, it includes a sentence recommending that manufacturers' instructions be followed carefully. Such advice presumes that the manufacturers' instructions address designing the sleeve to have the correct inner diameter and length, as well as positioning the sleeve properly, in order to limit the shear and bending forces at the connection. Unfortunately, since none of the steel tapping tee manufacturers recommend any precautions to limit shear and bending forces at the connection point, gas pipeline operators may not realize the importance of determining these parameters.

The *A.G.A. Plastic Pipe Manual for Gas Service* does not provide an explanation for the following sentence:

> Installation of the tee outlet at angles up to 45° from the vertical or along the axis of the main as a 'side saddle' or 'swing joint' may be considered to further minimize...stresses.

This sentence is subject to different interpretations and does not explain how stresses might be reduced. Moreover, many gas system pipeline operators recognize that installing services 90° from the main helps with future locating of the pipe and reduces the likelihood of excessive bending, which could generate excessive stress. In the view of the Safety Board, this sentence does not provide useful guidance as it is written, and the A.G.A. Plastic Materials Committee would be well advised to either expand on or delete this sentence.

A.G.A. Gas Engineering and Operating Practices Series -- Illustrations from the GEOP series show protective sleeves extending to undisturbed or compacted soil or to blocking. But these figures show the blocking positioned so that, under some conditions, either the edge of the blocking or the edge of the protective sleeve might provide a fixed contact point on the service pipe. The Safety Board notes that B31.8 and ASTM D2774 discourage supporting plastic pipe by the use of blocking. In the view of the Safety Board, these illustrations would provide better guidance if they were revised to eliminate showing the possibility of blocking or other fixed contact point supporting plastic pipe.

The Safety Board believes that the A.G.A. should revise its *Plastic Pipe Manual for Gas Service* and the *Gas Engineering and Operating Practices* series to provide complete and unambiguous guidance for limiting stress at plastic pipe service connections to steel mains.

GPTC Guide for Gas Transmission and Distribution Piping Systems -- The Safety Board has previously noted that a protective sleeve's correct inner diameter and length are important to protect the piping from excessive forces. The Safety Board even issued a safety recommendation that the GPTC Guide be modified accordingly. As a result of this safety recommendation, the GPTC Guide now includes guidance under 49 CFR 192.361 to install protective sleeves "designed for the specific connection...to reduce stress concentrations." Designing protective sleeves for the specific connection is presumed to include designing the sleeve for the correct inner diameter and length, and may also include positioning the sleeve correctly, since positioning the sleeve affects its effective length. However, if steel tapping tee manufacturers do not address the parameters for sleeve design and positioning, gas pipeline operators may not realize the importance of determining these parameters. The guidance would be much more useful to gas pipeline operators if the GPTC included in the guide a specific statement of the need to design protective sleeves so that they will have the correct inner diameter and length, as well as the need to properly position the sleeves.

Although the guide references the *A.G.A. Plastic Pipe Manual for Gas Service* in various locations, and this manual provides recommendations on bending limits, the guide does not reference this manual under the guide material under 49 CFR 192.361. Therefore, the Safety Board believes that the GPTC should revise the guide to include complete guidance for the proper installation of plastic service pipe connections to steel mains. The guidance should emphasize the need to limit pipe bending and should include a discussion of the proper design and positioning of a protective sleeve to limit stress at the connection.

ASTM -- ASTM D2774 recommends the use of a protective sleeve, if needed to protect against possible differential settlement. The standard practice additionally advises consultation with manufacturers, which would presumably address designing the sleeve with a proper diameter and length, as well as positioning the sleeve correctly. However, as noted previously, none of the steel tapping tee manufacturers has recommended precautions to limit stresses at the service to main connection; therefore, gas pipeline operators may not realize the importance of determining these parameters. Consequently, the Safety Board believes that the ASTM should revise ASTM D2774 to emphasize that a protective sleeve, in order to be effective, must be of the proper length and inner diameter for the particular connection and must be positioned properly.

Currently, manufacturers that provide protective sleeves have their own criteria for sleeve lengths and diameters. Some manufacturers' criteria are based on limiting stress to a maximum safe value,[82] while one manufacturer has advised the Safety Board that its sleeve is not designed to limit bending but only to guard against shear forces at the connection point. A published common criteria would better motivate a wider spectrum of manufacturers and gas operators to apply scientific reasoning to their decisions on protective sleeve use. A published common criteria would additionally provide guidance to gas operators who provide their own sleeves rather than using manufacturer-supplied sleeves. The Safety Board therefore believes that the ASTM should develop and publish standard criteria for the design of protective sleeves to limit stress intensification at plastic pipeline connections.

Guidance Manual for Operators of Small Natural Gas Systems -- The expressed purpose of RSPA's *Guidance Manual for Operators of Small Natural Gas Systems* is to assist nontechnically trained persons who operate small gas systems. However, the manual provides no caution against bending close to a plastic service connection to a steel main. The manual recommends following manufacturers' instructions and indicates that a properly designed sleeve should be used at this connection, which would address designing the sleeve with the proper diameter and length. However, as noted previously, none of the steel tapping tee manufacturers has recommended precautions to limit stresses at the service to main connection; therefore, nontechnically trained persons may not realize the importance of determining these parameters.

Because manufacturers' recommendations in the above areas are also currently inadequate, the Safety Board believes that RSPA should revise its *Guidance Manual for Operators of Small Natural Gas Systems* to include more complete guidance for the proper installation of plastic service pipe connections to steel mains. The guidance should address pipe bending limits and should emphasize that a protective sleeve, in order to be effective, must be of the proper length and inner diameter for the particular connection and must be positioned properly.

Manufacturers' Recommendations -- Reliance on manufacturers' recommendations is a common theme running through many of the primary published sources of industry guidance for limiting stress intensification on plastic piping. CSR PolyPipe was relatively new to providing polyethylene pipe to the gas market. When CSR PolyPipe entered the market, the three other major polyethylene piping manufacturers had already published installation recommendations to limit stress intensification, and plastic materials were vastly improved compared to earlier versions with respect to resistance to crack initiation and slow crack growth. CSR PolyPipe therefore saw less need to develop extensive recommendations. And although CSR PolyPipe does not manufacture steel tapping tees with compression ends for attachment to plastic services, it does manufacture the pipe that will be attached to steel tapping tees via mechanical compression couplings. To facilitate the safe use of plastic piping, the Safety Board believes that the PPI, of which all four of the major piping producers are members, should advise its plastic pipe manufacturing members to develop and publish recommendations for limiting shear and bending forces at plastic service pipe connections to steel mains.

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[82] Allman, W. B., "Determination of Stresses and Structural Performance in Polyethylene Gas Pipe and Socket Fittings Due to Internal Pressure and External Soil Loads," *1975 Operating Section Proceedings*, American Gas Association, 1975.

Compared to plastic piping manufacturers, steel tapping tee manufacturers may have much less technical expertise regarding the strength and failure modes of plastic pipe; however, steel tapping tee manufacturers, who have designed their rigid steel tees to connect to flexible plastic gas pipe, have a responsibility to provide recommendations for the safe use of their products. If a steel tee manufacturer believes that installation options are dependent on the type of plastic to be connected and that these options can be addressed only by the pipe manufacturer, the tee manufacturer has a responsibility to state that in its literature and to provide the gas system operator with direction for best using its product safely.

The Safety Board therefore believes that Continental, Dresser, Inner-Tite, and Mueller should develop and publish detailed recommendations and instructions for limiting shear and bending forces at locations where their steel tapping tees are used to connect service pipe to steel mains. While gas system operators have the option of not accepting manufacturers' recommendations, many gas system operators rely on manufacturers to provide installation recommendations for the safe use of their products. With published recommendations, gas system operators may be far less likely to overlook prudent construction practices, such as providing proper compaction and support, limiting bends, and using protective sleeves. Tee manufacturers may wish to make these published recommendations even more effective by packaging them with each tee shipped, thus ensuring that the gas operator or the tee installer, or both, will have ready access to them.

A Continental representative told the Safety Board that the protective sleeve it provides to customers as an option does not provide sufficient clearance to allow field wrap to be applied to the metallic portion under the sleeve as a way to prevent corrosion. The Safety Board concludes that the use of Continental tapping tees with Continental protective sleeves may leave the tapping tees susceptible to corrosion because the sleeves do not provide sufficient clearance for the application of field wrap to the metallic steel tapping tee. The Safety Board therefore believes that Continental should provide a means to ensure that use of Continental-designed protective sleeves with the company's steel tapping tees at plastic pipe connections to steel mains does not compromise corrosion protection for the connection.

Installation Issues at Site of Waterloo Accident -- Safety Board examination of the fracture surface and the failed pipe from the Waterloo accident revealed evidence of stress intensification. For example, the upper portion of the inside of the pipe showed the impression of the edge of the tee stiffener, indicating that the top of the pipe had been pressed down. The failure of the pipe can be directly associated with this stressed area, which was characterized by several brittle-like slow crack growth fractures that originated on or near the pipe inner wall just outside the depression associated with the tip of the tee stiffener. These slow crack fractures propagated through the wall of the pipe.

The stress intensification noted in the Waterloo pipe was consistent with the pipe's having been subjected to shear and bending forces generated primarily by soil settlement.[83] Soil settlement is a common source of stress intensification for buried plastic pipelines, and it can occur and contribute to a piping failure even though no observable voids are noted during a subsequent excavation. Ultimate settlement of backfill can take many years, and sometimes it only occurs after periods of heavy rains (such as the area experienced the previous year) or under additional external loading (such as that represented by truck traffic over the connection).

The accident investigation could not determine whether the ground settlement at Waterloo occurred because of inadequate compaction and support under the connection at the time it was installed, or whether it occurred despite initial adequate compaction and support. Nor could it be conclusively determined whether the amount of soil settlement was slight and generated relatively low stresses over a long

[83]The failed pipe also showed signs that the installed horizontal curve may have generated horizontal bending forces. Other factors contributing to stress at the connection included the pipe's internal pressure and may have included residual stresses inside the wall of the pipe resulting from the manufacturing process.

period of time, or whether the soil settlement was substantial and generated relatively high stresses over a relatively short period of time. Because of these uncertainties, investigators could not determine how much more resistance to crack initiation and slow crack growth the pipe would have needed to have successfully resisted the stresses to which it was subjected.

MidAmerican Energy, at the time of this accident investigation, had no installation standard that called for firm compacted support under plastic service connection points to steel mains. MidAmerican Energy connected plastic service pipe to mains via factory-joined plastic-to-steel transition fittings. As noted previously, the manufacturers for these specialty fittings, unlike steel tapping tee manufacturers, have protective sleeves available. Although MidAmerican Energy designed its own protective sleeves for this application, it did so without a design criteria for length or inner diameter, or for positioning the protective sleeves. Without such criteria, MidAmerican Energy may reduce the sleeve's effectiveness in limiting stress intensification. The Safety Board concludes that, because MidAmerican Energy's gas construction standards do not establish well-defined criteria for supporting plastic pipe connections to steel mains or for designing or installing its protective sleeves at these connections, these standards do not ensure that connections will be adequately protected from stress intensification. The Safety Board believes that MidAmerican Energy should modify its gas construction standards to require (1) firm compacted support under plastic service connections to steel mains, and (2) the proper design and positioning of protective sleeves at these connections.

The service involved in the Waterloo accident was installed with a horizontal bend that was sharper than that recommended by current gas industry guidance recommendations; however, the bend may have been installed in the direction of the residual coil bend. Gas industry recommendations do not address residual bending in the pipe, even though plastic piping is often delivered to job sites in banded coils, which leaves some residual bending in the piping even after the bands are removed. Installing coiled pipe with any necessary bending in the direction of the residual bend may be a good practice to limit stresses. Conversely, bending pipe against the direction of the residual coil bend, even if the resulting bend is in accordance with gas industry recommendations, will induce greater stresses.

Plastic piping manufacturers continue to have the best combination of technical expertise and practical knowledge for determining bend radius recommendations. Therefore, the Safety Board believes that the PPI should advise its plastic pipe manufacturing members to revise their pipeline bend radius recommendations as necessary to take into account the effects of residual coil bends in plastic piping.

Gas System Performance Monitoring

Federal regulations require that gas pipeline system operators have in place an ongoing program to monitor the performance of their piping systems. Before the Waterloo accident, Midwest Gas developed only a limited capability for monitoring and analyzing the condition of its gas system. For example, the company did not statistically correlate failure rates to the amounts of installed pipe provided by specific manufacturers. The design of the program meant that the relatively few areas with high failure rates (for example, those with Century pipe) were aggregated with and therefore masked by the large number of plastic piping installations that had low failure rates. Thus, the Midwest Gas surveillance program did not reveal the high failure rates associated with Century pipe. Only after the accident did Midwest Gas identify the Century pipe within its pipeline system as having high failure rates, even though the company could have collected and processed the same type of data and reached the same determination before the accident. If Midwest Gas had further correlated its data to years of installation, it may have also been able to examine the effects of its changing installation methods or changes in performance with different manufacturers through the years.

The Safety Board concludes that, before the Waterloo accident, the systems used by Midwest Gas Company for tracking, identifying, and statistically characterizing plastic piping failures did not permit an effective analysis of system failures and leakage history. The Safety Board further concludes that if, before the Waterloo accident, Midwest Gas had had an effective surveillance program that tracked and identified the high leakage rates associated with Century piping when subjected to stress intensification, the company could have implemented a replacement program for the pipe and may have replaced the failed service connection before the accident.

Since the accident, MidAmerican Energy has revised its systems, adding parameters to provide the company with added capability to sort failures. However, MidAmerican Energy has not chosen parameters that will allow an adequate analysis of its plastic piping system failures and leakage history. For example, the generic "improper installation" is a parameter to be linked to leaks; however, no parameters have been added for the presence, lack, improper design, or improper placement of a protective sleeve. And no parameters have been added to link leaks to squeeze locations, improper joining, or items to differentiate between insufficient support and excessive installed bending. The Safety Board therefore concludes that MidAmerican Energy's current systems for tracking, identifying, and statistically characterizing plastic piping failures do not enable an effective analysis of system failures and leakage history.

The Safety Board believes that MidAmerican Energy should, as a basis for the timely replacement of its plastic piping systems that indicate unacceptable performance, review its existing plastic piping surveillance and analysis program and make the changes necessary to ensure that the program is based on sufficiently precise factors such as piping manufacturer, installation date, pipe diameter, geographical location, and conditions and locations of failures.

An effective surveillance program would include the data base inputs that would allow the company to adequately monitor and characterize the types and causes of plastic piping field failures. The *A.G.A. Plastic Pipe Manual for Gas Service* recommends the use of a form for recording necessary information on plastic piping failures; this form may be helpful to MidAmerican Energy as it decides which data fields would be necessary to provide for an adequate analysis of its plastic piping system failures and leakage history. The *A.G.A. Plastic Pipe Manual for Gas Service* further recommends collecting this information, then performing visual examinations of the type and cause of failure and, in some instances, a laboratory analysis. The above steps may help MidAmerican Energy comprehensively monitor and address parts of its plastic pipeline system—other than those installations with Century pipe—that may also indicate unacceptable performance.

In a previous accident investigation report,[84] the Safety Board pointed out that many operators had not established procedures to comply with Federal regulations requiring surveillance and investigation of failures. The Safety Board recommended that RSPA:

> P-90-14
> Emphasize, as a part of OPS inspections and during training and State monitoring programs, the actions expected of gas operators to comply with the continuing surveillance and failure investigation, including laboratory examination requirements.

In a letter to the Safety Board, RSPA responded that the TSI had increased emphasis on gas surveillance and failure investigation in the operations block of its industry seminars held across the country. The letter stated that the TSI would incorporate a discussion of accident analysis into a new hazardous liquids seminar that was to be presented for the first time in FY 1992. Additionally, RSPA noted that it planned to place additional emphasis on continuing surveillance and failure investigation requirements in its new inspection forms at the time of the next revision. Based on this response, the Safety Board classified Safety Recommendation P-90-14 "Closed—Acceptable Action."

Despite the RSPA response to this safety recommendation, for a variety of reasons—including the inadequate performance monitoring

[84] National Transportation Safety Board Pipeline Accident Report--*Kansas Power and Light Company Natural Gas Pipeline Accidents, September 16, 1988, to March 29, 1989* (NTSB/PAR-90/03).

programs found at Midwest Gas/MidAmerican Energy, the susceptibility to brittle cracking of much of the polyethylene piping installed through the early 1980s, deficiencies noted in gas industry communications regarding poorly performing brands of polyethylene piping, and differences noted in the performance of different types and brands of polyethylene piping—RSPA may need to do more. Gas system operators may need to be advised once again of the importance of complying with Federal requirements for piping system surveillance and analyses. As is the case with older piping, an effective general pipeline surveillance program would be based on factors such as piping manufacturer, installation date, pipe diameter, operating pressure, leak history, geographical location, modes of failure (such as bending, inadequate support, rock impingement, or improper joining), location of failure (such as at the main to service or at pipe squeeze locations), and other factors such as the presence, absence, or misapplication of a sleeve. An effective program would also evaluate past piping and components installed, as well as past installation practices, to provide a basis for the replacement, in a planned, timely manner, of plastic piping systems that indicate unacceptable performance.

CONCLUSIONS

1. Plastic pipe extruded by Century Utility Products, Inc., and made from Union Carbide's DHDA 2077 Tan resin has poor resistance to brittle-like cracking under stress intensification, and this characteristic contributed to the Waterloo, Iowa, accident.

2. The procedure used in the United States to rate the strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.

3. Much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s may be susceptible to premature brittle-like failures when subjected to stress intensification, and these failures represent a potential public safety hazard.

4. Gas pipeline operators have had insufficient notification that much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s may be susceptible to brittle-like cracking and therefore may not have implemented adequate pipeline surveillance and replacement programs for their older piping.

5. Even though the Gas Research Institute has developed a significant amount of data about older plastic piping used for gas service, because the data have been published in codified terms, the information is not sufficiently useful to gas pipeline system operators.

6. Because guidance covering the installation of plastic piping is inadequate for limiting stress intensification at plastic service connections to steel mains, many of these connections may have been installed without adequate protection from shear and bending forces.

7. Because MidAmerican Energy Corporation's gas construction standards do not establish well-defined criteria for supporting plastic pipe connections to steel mains or for designing or installing its protective sleeves at these connections, these standards do not ensure that connections will be adequately protected from stress intensification.

8. Before the Waterloo, Iowa, accident, the systems used by Midwest Gas Company for tracking, identifying, and statistically characterizing plastic piping failures did not permit an effective analysis of system failures and leakage history.

9. If, before the Waterloo accident, Midwest Gas Company had had an effective surveillance program that tracked and identified the high leakage rates associated with Century Utility Products, Inc., piping when subjected to stress intensification, the company could have implemented a replacement program for the pipe and may have replaced the failed service connection before the accident.

10. MidAmerican Energy Corporation's current systems for tracking, identifying, and statistically characterizing plastic piping failures do not enable an effective analysis of system failures and leakage history.

11. The use of Continental Industries, Inc., tapping tees with the company's protective sleeves may leave the tapping tees susceptible to corrosion because the sleeves do not provide sufficient clearance for the application of field wrap to the metallic steel tapping tee.

RECOMMENDATIONS

As a result of this special investigation, the National Transportation Safety Board makes the following safety recommendations:

--to the Research and Special Programs Administration:

Notify pipeline system operators who have installed polyethylene gas piping extruded by Century Utility Products, Inc., from Union Carbide Corporation DHDA 2077 Tan resin of the piping's poor brittle-crack resistance. Require these operators to develop a plan to closely monitor the performance of this piping and to identify and replace, in a timely manner, any of the piping that indicates poor performance based on such evaluation factors as installation, operating, and environmental conditions; piping failure characteristics; and leak history. (P-98-1)

Determine the extent of the susceptibility to premature brittle-like cracking of older plastic piping (beyond that piping marketed by Century Utility Products, Inc.) that remains in use for gas service nationwide. Inform gas system operators of the findings and require them to closely monitor the performance of the older plastic piping and to identify and replace, in a timely manner, any of the piping that indicates poor performance based on such evaluation factors as installation, operating, and environmental conditions; piping failure characteristics; and leak history. (P-98-2)

Immediately notify those States and territories with gas pipeline safety programs of the susceptibility to premature brittle-like cracking of much of the plastic piping manufactured from the 1960s through the early 1980s and of the actions that the Research and Special Programs Administration will require of gas system operators to monitor and replace piping that indicates unacceptable performance. (P-98-3)

In cooperation with the manufacturers of products used in the transportation of gases or liquids regulated by the Office of Pipeline Safety, develop a mechanism by which the Office of Pipeline Safety will receive copies of all safety-related notices, bulletins, and other communications regarding any defect, unintended deviation from design specification, or failure to meet expected performance of any piping or piping product that is now in use or that may be expected to be in use for the transport of hazardous materials. (P-98-4)

Revise the *Guidance Manual for Operators of Small Natural Gas Systems* to include more complete guidance for the proper installation of plastic service pipe connections to steel mains. The guidance should address pipe bending limits and should emphasize that a protective sleeve, in order to be effective, must be of the proper length and inner diameter for the particular connection and must be positioned properly. (P-98-5)

--to the Gas Research Institute:

Publish the codes used to identify plastic piping products in previous Gas Research Institute studies to make the information contained in these studies more useful to pipeline system operators. (P-98-6)

--to the Plastics Pipe Institute:

Advise your members to notify pipeline system operators if any of their piping products, or materials used in the manufacture of piping products, currently in service for natural gas or other hazardous materials indicate poor resistance to brittle-like failure. (P-98-7)

Advise your plastic pipe manufacturing members to develop and publish recommendations for limiting shear and bending forces at plastic service pipe connections to steel mains. (P-98-8)

Advise your plastic pipe manufacturing members to revise their pipeline bend radius recommendations as necessary to take into account the effects of residual coil bends in plastic piping. (P-98-9)

--to the Gas Piping Technology Committee:

Revise the *Guide for Gas Transmission and Distribution Piping Systems* to include complete guidance for the proper installation of plastic service pipe connections to steel mains. The guidance should emphasize the need to limit pipe bending and should include a discussion of the proper design and positioning of a protective sleeve to limit stress at the connection. (P-98-10)

--to the American Society for Testing and Materials:

Revise ASTM D2774 to emphasize that a protective sleeve, in order to be effective, must be of the proper length and inner diameter for the particular connection and must be positioned properly. (P-98-11)

Develop and publish standard criteria for the design of protective sleeves to limit stress intensification at plastic pipeline connections. (P-98-12)

--to the American Gas Association:

Revise your *Plastic Pipe Manual for Gas Service* and your *Gas Engineering and Operating Practices* series to provide complete and unambiguous guidance for limiting stress at plastic pipe service connections to steel mains. (P-98-13)

--to MidAmerican Energy Corporation:

Modify your gas construction standards to require (1) firm compacted support under plastic service connections to steel mains, and (2) the proper design and positioning of protective sleeves at these connections. (P-98-14)

As a basis for the timely replacement of your plastic piping systems that indicate unacceptable performance, review your existing plastic piping surveillance and analysis program and make the changes necessary to ensure that the program is based on sufficiently precise factors such as piping manufacturer, installation date, pipe diameter, geographical location, and conditions and locations of failures. (P-98-15)

--to Continental Industries, Inc.:

Provide a means to ensure that the use of your protective sleeves with your tapping tees at plastic pipe connections to steel mains does not compromise corrosion protection for the connection. (P-98-16)

--to Continental Industries, Inc. (P-98-17):

--to Dresser Industries, Inc. (P-98-18):

--to Inner-Tite Corporation (P-98-19):

--to Mueller Company (P-98-20):

Develop and publish recommendations and instructions for limiting shear and bending forces at locations where your steel tapping tees are used to connect plastic service pipe to steel mains.

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

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April 23, 1998

National Transportation Safety Board
Washington, D.C. 20594

Pipeline Accident Brief

Pipeline Accident Number:	DCA-95-MP-001
Type of System:	Gas distribution
Accident Type:	Explosion and Fire
Location:	Waterloo, Iowa
Date and Time:	October 17, 1994; 10:07 a.m. local
Owner/Operator:	Midwest Gas Company[1]
Fatalities/Injuries:	Six fatalities and seven non-fatal injuries
Damage:	$250,000
Material Released:	Natural Gas
Pipeline Pressure:	25 pounds per square inch, gauge (psig)
Component Affected:	1/2-inch plastic pipe at steel tapping tee mechanical compression connection to steel main

The Accident

At 10:07 a.m. central daylight savings time on Monday, October 17, 1994, a natural gas explosion and fire destroyed a one-story, wood frame building in Waterloo, Iowa. The force of the explosion scattered debris over a 200-foot radius.

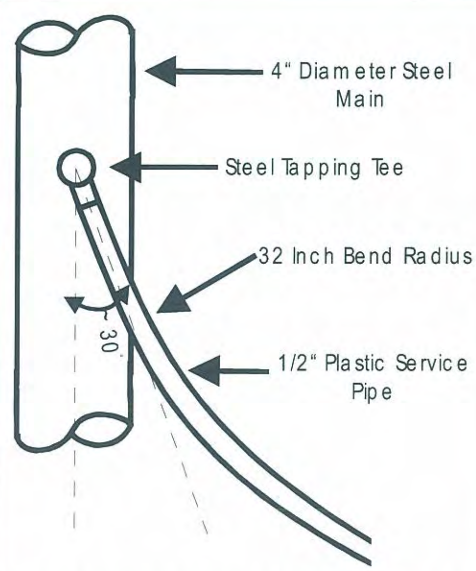
Six persons inside the building died, and one person sustained serious injuries. Three persons working in an adjacent building sustained minor injuries when a wall of the building collapsed inward from the force of the explosion. The explosion also damaged nine parked cars. A person in a vehicle who had just exited the adjacent building suffered minor injuries. Additionally, two firefighters sustained minor injuries during the emergency response. Two other nearby buildings also sustained structural damage and broken windows.

Site Information

The destroyed building was a neighborhood tavern known as Buzz's Bar. Adjacent to and east of the bar was Woodland Pattern Company, which was provided gas service by a 1/2-inch-diameter plastic polyethylene service pipeline. The service pipeline was installed by Iowa Public Service Company on September 3, 1971, and was operated at a maximum pressure of 25 psig.

[1]Because of a series of organizational changes and mergers, the name of the owner/operator of the gas system at Waterloo, Iowa, has changed over the years. In 1971, Iowa Public Service Company installed the gas service that ultimately failed. At the time of the accident, the gas system operator was known as Midwest Gas Company, while the current operator's name is MidAmerican Energy Corporation.

The underground pipeline connected with the steel gas main and entered the Woodland Pattern Company building between Buzz's Bar and the Woodland Pattern Company.



Service-to-main connection at site of Waterloo accident.

The area between Buzz's Bar and Woodland Pattern Company was unpaved and, according to those familiar with the location, was regularly used by beer trucks making deliveries to Buzz's Bar and by semitrailers delivering materials to Woodland Pattern Company. These trucks had been seen to drive over the area of the piping assembly that cracked. At various times, beer trucks servicing Buzz's Bar had been observed to park directly over the location of the pipe break. One witness stated that a beer delivery truck had been parked over the area of the pipe break at approximately 7:00 a.m. on the day of the accident.

Excavations following the accident uncovered a 4-inch-diameter steel main at a depth of about 3 feet. Welded to the top of the main was a steel tapping tee with markings indicating that the tee had been manufactured by Continental Industries, Inc. (Continental). Connected to the steel tee was a 1/2-inch-diameter plastic service pipe leading to Woodland Pattern Company. Markings on the plastic pipe indicated that it was a medium-density polyethylene material manufactured on June 11, 1970, in accordance with American Society for Testing and Materials (ASTM) standard D2513, and marketed by Century Utility Products, Inc. (Century). A circumferential crack through the plastic pipe was found at the tip of the tee's internal stiffener that protruded beyond the tee's coupling nut. A 1- to 2-foot-diameter "hard ball" surrounded the cracked pipe.[2]

Because Safety Board investigators did not arrive at the accident site until after excavation of the failed pipe, investigators had to consult several sources to determine the condition of the piping at the time of excavation. Photographs of the excavation, a Waterloo Fire Department video tape, and several witnesses all indicated that the downstream portion of the plastic pipe was found broken off and vertically displaced below the plastic pipe portion still attached to the steel tee. However, an Iowa State Fire Marshall's Office investigator, who directed and participated in the excavation, reported that the pipe was displaced by the excavation activities. That investigator also reported no observed voids in the soil under the failed assembly.

Service-to-main connection at site of Waterloo accident.

MidAmerican Energy estimated that the steel tee on the steel main was installed so that the polyethylene pipe exited the tee at an approximate 30° angle to the steel main. (See figure.)

[2]A "hard ball" is a term used in the gas industry for a soil condition where leaking natural gas over a period of time dries and hardens the soil adjacent to the leak.

The plastic service pipe leaving the tee immediately curved horizontally. After a portion of the pipe was taken to the laboratory for testing, the bend radius was measured at about 34 inches. Based on field conditions and photos, MidAmerican Energy has estimated the original installed horizontal bend radius to be approximately 32 inches.[3] This bend is sharper than currently recommended by industry guidelines for modern piping adjacent to fittings. However, a former Iowa Public Service Company employee stated that Iowa Public Service Company, in an effort to reduce the stress at the connection point, often attempted to install polyethylene services at an angle to the main to match the residual bend left after uncoiling the pipe.[4] This former employee stated that no set time was prescribed to allow for complete relaxing of the pipe, but that the pipe would be placed in the ditch, and the crews would weld the tee at what they judged to be the appropriate angle, in consideration of the natural bend of the pipe.

Also immediately from the tee outlet, the polyethylene bent downward. The tee outlet did not have a protective sleeve to reduce shear and bending forces at the connection.

Tests and Examination

Samples recovered from the plastic service line underwent several laboratory tests under the supervision of the Safety Board. Two of these tests were meant to roughly gauge the pipe's susceptibility to brittle-like cracking. These tests were a compressed ring environmental stress crack resistance (ESCR) test in accordance with ASTM F1248 and a notch tensile test known as a PENT test that is now ASTM F1473. Lower failure times in these tests indicate greater susceptibility to brittle-like cracking under test conditions. The ESCR testing of 10 samples from the pipe yielded a mean failure time of 1.5 hours, and the PENT testing of 2 samples yielded failure times of 0.6 and 0.7 hours. Test values this low have been associated with materials having poor performance histories[5] characterized by high leakage rates at points of stress intensification due to crack initiation and slow crack growth typical of brittle-like cracking.

To facilitate identification, the fracture surfaces were divided into two regions, A and B, around the circumference of the failed pipe. If a cross section of the pipe, looking toward the tee, were superimposed on a clock face, region A would extend from approximately the 9:00 position up across the top and down to about 1:30, with the center of the region at about 11:15. Region B took up the remainder of the pipe surface, extending from about the 1:30 position down across the bottom and up to 9:00.

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[3]Polyethylene pipe installed with a bend often, over time, permanently deforms in the direction of the bend. This permanent deformation partially reduces the stresses generated by the bending forces. When the pipe is released from its installation configuration, the pipe can straighten to some extent.

[4]MidAmerican Energy has indicated that Iowa Public Service's plastic service pipe was received in coils from Century. After uncoiling the pipe, some residual bending remains. The amount of residual bending depends on the factory coiling conditions.

[5]Uralil, F. S., et al., *The Development of Improved Plastic Piping Materials and Systems for Fuel Gas Distribution—Effects of Loads on the Structural and Fracture Behavior of Polyolefin Gas Piping*, Gas Research Institute Topical Report, 1/75 - 6/80, NTIS No. PB82-180654, GRI Report No. 80/0045, 1981, and Hulbert, L. E., Cassady, M. J., Leis, B. N., Skidmore, A., *Field Failure Reference Catalog for Polyethylene Gas Piping, Addendum No. 1*, Gas Research Institute Report No. 84/0235.2, 1989, and Brown, N. and Lu, X., "Controlling the Quality of PE Gas Piping Systems by Controlling the Quality of the Resin," *Proceedings Thirteenth International Plastic Fuel Gas Pipe Symposium*, pp 327-338, American Gas Association, Gas Research Institute, Battelle Columbus Laboratories, 1993.

The fracture in region A was located immediately outside the tee's internal stiffener. The crack was perpendicular to the pipe wall and directly in line with the end of the tee's internal stiffener. The inside surface of the pipe throughout region A was characterized by a circumferential impression from the tip of the tee's stiffener. A similar impression was not found in region B. This impression was only found on the pipe segment that was still attached to the steel tee, and was not evident on any part of the pipe segment that was detached from the steel tee. Region A was characterized by several brittle-like slow crack growth fractures, each of which initiated on or near the pipe inner wall just outside the depression associated with the tip of the tapping tee's stiffener. These slow crack fractures propagated on almost parallel planes slightly offset from each other through the wall of the pipe. As the cracks from different planes continued to grow and began to overlap one another, ductile tearing occurred between the planes, which produced a jagged appearance in parts of the overall circumferential crack in region A Thus, even though substantial deformation was observed in part of the fracture, the initiating cracks were still classified as brittle-like.

Region B contained two brittle-like crack growth sections that initiated from each end of region A. Cracks from each end of region A propagated through region B on approximate 45° planes towards the tee (partially exposing the tee's stiffener) and met at the bottom (the 6:00 position). The remaining ligament tore with visible deformation at the bottom.

Laboratory comparisons showed that the fractures that initiated and grew in region A were consistent with fractures generated by long-term shear and bending forces at the end of the stiffener. The fractures in region B were consistent with a continuation of the same loading system described for region A but occurred subsequent to those in region A. The last ligament that fractured at the 6:00 position in region B was consistent with ductile tearing. Examination could not determine whether the last remaining ligament tore because of concentrated stresses prior to the excavation or because of excavation activities after the accident.

Other Information

Flooding was reported in the area during the summer of 1993. Midwest Gas's most recent leak surveys, performed in March 1994, did not detect a leak in this area. Records of odorant tests performed in September 1994 and on October 17, 1994 (two and a half hours after the accident), show odorant levels that met the level required by Federal standards.[6]

Probable Cause

The National Transportation Safety Board determines that the probable cause of the natural gas explosion and fire in Waterloo, Iowa, was stress intensification, primarily generated by soil settlement at a connection to a steel main, on a 1/2-inch polyethylene pipe that had poor resistance to brittle-like cracking.

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[6]Federal standards require the odorant in natural gas systems to be detectable at one-fifth of the lower explosive limit, which is typically at gas/air concentrations of 0.9 to 1.0 percent and above.

Organizations, Agencies, and Associations Referenced in this Report

American Gas Association (A.G.A.)
An organization dedicated to promoting and protecting the interests of its member natural gas local distribution companies. The A.G.A. has approximately 300 members, of which about 250 are natural gas local distribution companies.

American Society for Testing and Materials (ASTM)
An organization that provides a forum for producers, users, consumers, and others with a common interest, including representatives of government and academia, who come together to write standards for materials, products, systems, and services.

Gas Piping Technology Committee (GPTC)
An organization dedicated to the development of the *GPTC Guide for Gas Transmission and Distribution Piping Systems* (*GPTC Guide*). The purpose of the *GPTC Guide* is to provide assistance to gas pipeline system operators in complying with Federal regulations addressing the transportation of natural and other gases by pipeline.

Gas Research Institute (GRI)
A research, development, and commercialization organization dedicated to the interests of the natural gas industry. The organization's mission is to discover, develop, and deploy technologies and information that benefit gas customers and the industry.

Plastics Pipe Institute (PPI)
A manufacturers organization, the PPI is an operating unit of the Society of the Plastics Industry. Members of the PPI share a common interest in broadening market opportunities through the effective use of plastic piping in water and gas distribution, sewage and wastewater transport, oil and gas production, and in industrial, mining, power, communications, and irrigation applications.

Office of Pipeline Safety (OPS)
The Research and Special Programs Administration (see below) acts through the OPS to administer the U.S. Department of Transportation's national regulatory program to ensure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. The OPS develops regulations and other mechanisms to ensure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities.

Research and Special Programs Administration (RSPA)
A part of the U.S. Department of Transportation, RSPA has responsibility for emergency preparedness, research and technology, and transportation safety. The agency's safety mandate is to protect the Nation from the risks inherent in the transportation of hazardous materials by all transportation modes, including pipelines. RSPA carries out its pipeline safety and training programs through the Office of Pipeline Safety (see above).

National Transportation Safety Board

Washington, D.C. 20594

Safety Recommendation

Date: April 30, 1998

In reply refer to: P-98-1 through -5

Ms. Kelley Coyner
Acting Administrator
Research and Special Programs Administration
400 7th Street, S.W.
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Despite the general acceptance of plastic piping as a safe and economical alternative to piping made of steel or other materials, the Safety Board notes that a number of pipeline accidents it has investigated have involved plastic piping that cracked in a brittle-like manner. For example, on October 17, 1994, an explosion and fire in Waterloo, Iowa, destroyed a building and damaged other property. Six persons died and seven were injured in the accident. The Safety Board investigation determined that natural gas had been released from a plastic service pipe that had failed in a brittle-like manner at a connection to a steel main.

The Safety Board also investigated a gas explosion that resulted in 33 deaths and 69 injuries in San Juan, Puerto Rico, in November 1996.[1] The Safety Board's investigation determined that the explosion resulted from ignition of propane gas that had migrated under pressure from a failed plastic pipe that displayed evidence of brittle-like circumferential cracking.

The Railroad Commission of Texas investigated a natural gas explosion and fire that resulted in one fatality in Lake Dallas, Texas. in August 1997.[2] A metal pipe pressing against a plastic pipe generated stress intensification that led to a brittle-like crack in the plastic pipe.

A broader Safety Board survey of the accident history of plastic piping suggested that the material may be susceptible to premature brittle-like cracking under conditions of stress intensification. No statistics exist that detail how much and from what years any plastic piping may already have been replaced; however, hundreds of thousands of miles of plastic piping have been installed, with a significant amount of it having been installed prior to the mid-1980s. Any

[1]For more information, see National Transportation Safety Board Pipeline Accident Report--*San Juan Gas Company, Inc./Enron Corp., Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996* (NTSB/PAR-97/01).

[2]Railroad Commission of Texas Accident Investigation No 97-AI-055, October 31, 1997

vulnerability of this material to premature failure could represent a serious potential hazard to public safety.

In an attempt to gauge the extent of brittle-like failures in plastic piping and to assess trends and causes, the Safety Board examined pipeline accident data compiled by RSPA. The examination revealed that the data were insufficient to serve as a basis for assessing the long-term performance of plastic pipe.

Lacking adequate data from RSPA, the Safety Board reviewed published technical literature and contacted more than 20 experts in gas distribution plastic piping to determine the estimated frequency of brittle-like cracks in plastic piping. The majority of the published literature and experts indicated that failure statistics would be expected to vary from one gas system operator to another based on factors such as brands and dates of manufacture of plastic piping in service, installation practices, and ground temperatures, but they indicated that brittle-like failures, as a nationwide average, may represent the second most frequent failure mode for older plastic piping, exceeded only by excavation damage.

The Safety Board asked several gas system operators about their direct experience with brittle-like cracks. Four major gas system operators reported that they had compiled failure statistics sufficient to estimate the extent of brittle-like failures. Three of those four said that brittle-like failures are the second most frequent failure mode in their plastic pipeline systems. One of these operators supplied data showing that it experienced at least 77 brittle-like failures in plastic piping in 1996 alone.

As an outgrowth of the Safety Board's investigations into the Waterloo, Iowa; San Juan, Puerto Rico; and about a dozen other accidents, and in view of indications that some plastic piping, particularly older piping, may be subject to premature failure attributable to brittle-like cracking, the Safety Board undertook a special investigation of polyethylene gas service pipe. The investigation addressed the following safety issues:[3]

- The vulnerability of plastic piping to premature failures due to brittle-like cracking;
- The adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains; and
- Performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems.

The Waterloo, San Juan, and Lake Dallas accidents were only three of the most recent in a series of accidents in which brittle-like cracks in plastic piping have been implicated. In Texas in 1971, natural gas migrated into a house from a brittle-like crack at the connection of a plastic

[3]For more information, see National Transportation Safety Board Pipeline Special Investigation Report--*Brittle-like Cracking in Plastic Pipe for Gas Service* (NTSB/SIR-98/01).

service line to a plastic main.[4] The gas ignited and exploded, destroying the house and burning one person. The investigation determined that vertical loading over the connection generated long-term stress that led to the crack.

A 1973 natural gas explosion and fire in Maryland severely damaged a house, killed three occupants, and injured a fourth.[5] The Safety Board's investigation revealed that a brittle-like crack occurred in a plastic pipe as a result of an occluded particle that created a stress point.

The Safety Board's investigation of a natural gas explosion and fire that resulted in three fatalities in North Carolina in 1975[6] determined that the gas had accumulated because a concrete drain pipe resting on a plastic service pipe had precipitated two cracks in the plastic pipe. Available documentation suggests that these cracks were brittle-like.

A 1978 natural gas accident in Arizona destroyed 1 house, extensively damaged 2 others, partially damaged 11 other homes, and resulted in 1 fatality and 5 injuries.[7] Available documentation indicates that the gas line crack that caused the accident was brittle-like.

A 1978 accident in Nebraska involved the same brand of plastic piping as that involved in the Waterloo accident. A crack in a plastic piping fitting resulted in an explosion that injured one person, destroyed one house, and damaged three other houses.[8] The Safety Board determined that inadequate support under the plastic fitting resulted in long-term stress intensification that led to the formation of a circumferential crack in the fitting. Available documentation indicates that the crack was brittle-like.

A December 1981 natural gas explosion and fire in Arizona destroyed an apartment, damaged five other apartments in the same building, damaged nearby buildings, and injured three occupants.[9] The Safety Board's investigation determined that assorted debris, rocks, and chunks of concrete in the excavation backfill generated stress intensification that resulted in a circumferential crack in a plastic pipe at a connection to a plastic fitting. Available documentation indicates that the crack was brittle-like.

A July 1982 natural gas explosion and fire in California destroyed a store and two residences, severely damaged nearby commercial and residential structures, and damaged

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[4]National Transportation Safety Board Pipeline Accident Report--*Lone Star Gas Company, Fort Worth, Texas, October 4, 1971* (NTSB/PAR-72/5).

[5]National Transportation Safety Board Pipeline Accident Report--*Washington Gas Light Company, Bowie, Maryland, June 23, 1973* (NTSB/PAR-74/5).

[6]National Transportation Safety Board Pipeline Accident Brief--"Natural Gas Corporation, Kinston, North Carolina, September 29, 1975."

[7]National Transportation Safety Board Pipeline Accident Brief--"Arizona Public Service Company, Phoenix, Arizona, June 30, 1978."

[8]National Transportation Safety Board Pipeline Accident Brief--"Northwestern Public Service, Grand Island, Nebraska, August 28, 1978."

[9]National Transportation Safety Board Pipeline Accident Brief--"Southwest Gas Corporation, Tucson, Arizona, December 3, 1981."

automobiles.[10] The Safety Board's investigation identified a longitudinal crack in a plastic pipe as the source of the gas leak that led to the explosion. Available documentation indicates that the crack was brittle-like.

A September 1983 natural gas explosion in Minnesota involved the same brand of plastic piping as that involved in the Waterloo and Nebraska accidents.[11] The explosion destroyed one house and damaged several others, and injured five persons. The Safety Board's investigation determined that rock impingement generated stress intensification that resulted in a crack in a plastic pipe. Available documentation indicates that the crack was brittle-like.

One woman was killed and her 9-month-old daughter injured in a December 1983 natural gas explosion and fire in Texas.[12] The Safety Board's investigation determined that the source of the gas leak was a brittle-like crack that had resulted from damage to the plastic pipe during an earlier squeezing operation to control gas flow.[13]

A September 1984 natural gas explosion in Arizona resulted in five fatalities, seven injuries, and two destroyed apartments.[14] The Safety Board's investigation determined that a reaction between a segment of plastic pipe and some liquid trapped in the pipe weakened the pipe and led to a brittle-like crack.

Excavations following the Waterloo, Iowa, accident uncovered, at a depth of about 3 feet, a 4-inch steel main.[15] Welded to the top of the main was a steel tapping tee. Connected to the steel tee was a 1/2-inch plastic service pipe. Markings on the plastic pipe indicated that it was a medium-density polyethylene material manufactured on June 11, 1970, in accordance with American Society for Testing and Materials (ASTM) standard D2513. The pipe had been marketed by Century Utility Products, Inc. (Century). The plastic pipe was found cracked at the end of the tee's internal stiffener and beyond the coupling nut.

The investigation determined that much of the top portion of the circumference of the pipe immediately outside the tee's internal stiffener displayed several brittle-like slow crack initiation and growth fracture sites. These slow crack fractures propagated on almost parallel planes slightly offset from each other through the wall of the pipe. As the slow cracks from different planes continued to grow and began to overlap one another, ductile tearing occurred

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[10]National Transportation Safety Board Pipeline Accident Brief--"Pacific Gas and Electric Company, San Andreas, California, July 8, 1982."

[11]National Transportation Safety Board Pipeline Accident Brief--"Northern States Power Company, Newport, Minnesota, September 19, 1983."

[12]National Transportation Safety Board Pipeline Accident Brief--"Lone Star Gas Company, Terell, Texas, December 9, 1983."

[13]Plastic pipe is sometimes squeezed to control the flow of gas. In some cases, squeezing plastic pipe can damage it and make it more susceptible to brittle-like cracking.

[14]National Transportation Safety Board Pipeline Accident Report--*Arizona Public Service Company Natural Gas Explosion and Fire, Phoenix, Arizona, September 25, 1984* (NTSB/PAR-85/01).

[15]For more information, see Pipeline Accident Brief in appendix to National Transportation Safety Board Pipeline Special Investigation Report--*Brittle-like Cracking in Plastic Pipe for Gas Service*.

between the planes. Substantial deformation was observed in part of the fracture; however, the initiating cracks were still classified as brittle-like.

Samples recovered from the plastic service line underwent several laboratory tests under the supervision of the Safety Board. Two of these tests were meant to roughly gauge the pipe's susceptibility to brittle-like cracking. These tests were a compressed ring environmental stress crack resistance (ESCR) test in accordance with ASTM F1248 and a notch tensile test known as a PENT test that is now ASTM F1473. Lower failure times in these tests indicate a greater susceptibility to brittle-like cracking under the test conditions. The ESCR testing of 10 samples from the pipe yielded a mean failure time of 1.5 hours, and the PENT testing of 2 samples yielded failure times of 0.6 and 0.7 hours. Test values this low have been associated with materials having poor performance histories[16] characterized by high leakage rates at points of stress intensification due to crack initiation and slow crack growth typical of brittle-like cracking. The Safety Board has investigated two other pipelines accidents, one in Nebraska in 1978 and one in Minnesota in 1983, that involved Century piping. The Safety Board is also aware of four other accidents that it did not investigate that involved the same brand of piping.

The Century pipe involved in the Waterloo accident was made from Union Carbide's DHDA 2077 Tan resin. Although Union Carbide's laboratory data supported Union Carbide's claimed strength, the Safety Board's review of the same data showed that the material had an early ductile-to-brittle transition, indicating poor resistance to brittle-like fractures.

In the early 1970s, a Minnesota gas system operator tested a number of piping products made from DHDA 2077 Tan resin, including those marketed by Century, as part of its comprehensive specification, testing, and evaluation program. The company rejected piping made from the Union Carbide product for use in its system based on the results of sustained pressure tests. Union Carbide, in 1971, acknowledged that its DHDA 2077 Tan resin material had a lower pressure rating at 100 °F than did DuPont's polyethylene pipe material.

Midwest Gas, the Waterloo, Iowa, gas operator at the time of the explosion and fire, had experienced at least three other significant failures involving Century pipe. The most recent failures, occurring between 1992 and 1994, prompted the company to collect samples of the Century material for independent laboratory testing. Samples were being gathered for testing at the time of the Waterloo accident. The subsequent laboratory report indicated that the Century piping had poor resistance to slow crack growth.

Midwest Gas's subsequent analysis of the company's leakage history concluded that its installations with Century piping had failure rates significantly higher than those with piping

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[16]Uralil, F. S., et al., *The Development of Improved Plastic Piping Materials and Systems for Fuel Gas Distribution—Effects of Loads on the Structural and Fracture Behavior of Polyolefin Gas Piping*, Gas Research Institute Topical Report, 1/75 - 6/80, NTIS No. PB82-180654, GRI Report No. 80/0045, 1981; Hulbert, L. E., Cassady, M. J., Leis, B. N., Skidmore, A., *Field Failure Reference Catalog for Polyethylene Gas Piping, Addendum No. 1*, Gas Research Institute Report No. 84/0235.2, 1989; and Brown, N. and Lu, X., "Controlling the Quality of PE Gas Piping Systems by Controlling the Quality of the Resin," *Proceedings, Thirteenth International Plastic Fuel Gas Pipe Symposium*, pp. 327-338, American Gas Association, Gas Research Institute, Battelle Columbus Laboratories, 1993.

from other manufacturers. Midwest Gas had received warnings from two pipe fitting manufacturers against use of their products with Century pipe because of Century pipe's susceptibility to brittle-like cracking. The current operating company in the Waterloo, Iowa, area, MidAmerican Energy, has, since the accident, replaced all the identified Century piping in its gas pipeline system.

The Safety Board concluded that plastic pipe extruded by Century Utility Products, Inc., and made from Union Carbide's DHDA 2077 Tan resin has poor resistance to brittle-like cracking under stress intensification, and this characteristic contributed to the Waterloo, Iowa, accident.

While Century piping has been identified specifically as being subject to brittle-like cracking (slow crack growth), evidence suggests that much of the early polyethylene piping may be more susceptible to such cracking than originally thought and thus may also be subject to premature failure.

The procedure used in the United States to rate the strength of plastic pipe, which was developed in the early 1960s, involved subjecting test piping to different stress values and recording how much time elapsed before the piping ruptured. The stress rupture data of the samples were then plotted, and a best-fit straight line was derived to represent the material's decline in rupture resistance as its time under stress increased.

To meet the requirements of the procedure, at least one tested sample had to be able to withstand stress rupture testing until at least 10,000 hours, or slightly more than 1 year. The straight line that was plotted to describe the data for this material was extrapolated out by a factor of 10, to 100,000 hours (about 11 years). The point at which the sloping straight line intersected the 100,000-hour point indicated the appropriate hydrostatic design basis for this material.

A key assumption characterized the assignment of a hydrostatic design basis under the procedure: The procedure assumed that the gradual decline in the strength of plastic piping material as it was subjected to stress over time would continue to be described by a straight line. In the early 1960s, the industry had little long-term experience with plastic piping, and a straight line seemed to represent the response of the material to laboratory stress testing. With little other information on which to base strength estimations, the straight-line assumption appeared valid. This procedure and assumption for rating the strength were incorporated into industry and government requirements.

As experience grew with plastic piping materials and as better testing methods were developed, however, the straight-line assumptions of the procedure came to be challenged. Elevated-temperature testing indicated that polyethylene piping can exhibit a decline in strength that does not follow the straight-line assumption, but instead shows a downturn. The difference between the actual (falloff) and projected (straight line) strengths became even more pronounced as the lines were extrapolated beyond 100,000 hours.

The combination of more durable modern plastic piping materials and more realistic strength testing has rendered the strength ratings of modern plastic piping much more reliable.

Unfortunately, much of the early plastic piping was sold and installed with expectations of strength and long-term performance that, because they were based on questionable assumptions about long-term performance, may not have been valid. This is borne out by data from a variety of sources. The history of strength rating requirements, a review of the piping properties and literature, and observations of several experts with extensive experience in plastic piping, all suggest that much of the polyethylene pipe, depending upon the brands, manufactured from the 1960s through the early 1980s fails at lower stresses and after less time than originally projected. The Safety Board therefore concluded that the procedure used in the United States to rate the strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.

Another important assumption of the design protocol for plastic pipe involved the ductility of the materials. It was assumed, based on short-term tests, that plastic piping had long-term ductile properties. Ductile material, by bending, expanding, or flexing, can redistribute stress concentrations better than can brittle material, such as cast iron. Notable from results of tests performed under the strength-rating procedure was that those short-term stress ruptures in the testing process tended to be characterized by substantial material deformation in the area of the rupture. This deformation described a material with obvious ductile properties. However, it was shown that, as time-to-failure increased in stress rupture tests, failures in several materials occurred as slit failures that, because they were not accompanied by substantial deformation, were more typical of brittle-like failures. These slit or brittle-like failures were characterized by crack initiation and slow crack growth. The procedure used to rate the strength of plastic pipe did not distinguish between ductile fractures and slit fractures and assumed that both types of failures would be described by the same straight line.

The assumption of ductility of plastic piping had important safety ramifications. For example, a number of experts believed it was safe to design plastic piping installations based on stresses primarily generated by internal pressure and to give less consideration to stress intensification generated by external loading. Ductile material reduces stress intensification by localized yielding, or deformation.

As noted previously, laboratory data supported the strength rating assigned to DHDA 2077 Tan resin by the process used at the time to rate strength; nevertheless, the material showed evidence of early ductile-to-brittle transition. The fact that the process used to measure the long-term durability of piping materials did not reveal the susceptibility to premature brittle-like cracking of the DHDA 2077 Tan material highlights the weaknesses of the process in use at the time. More significantly, it calls into question the durability of other early materials that were rated using the same process and that remain in service today. This concern is heightened by the fact that, in addition to the Waterloo accident involving Century pipe and DHDA 2077 Tan resin, other accidents investigated or documented by the Safety Board have demonstrated that brittle-like cracking occurs in other older plastic piping as well.

All available evidence indicates that polyethylene piping's resistance to brittle-like cracking has improved significantly through the years. Several experts in gas distribution plastic piping have told the Safety Board that a majority of the polyethylene piping manufactured in the 1960s and early 1970s had poor resistance to brittle-like cracking, while only a minority of that manufactured by the early 1980s could be so characterized.[17] Several gas system operators have told the Safety Board that they are aware of no instances of brittle-like cracking with their own modern polyethylene piping installations.

Premature brittle cracking in plastic piping is a complex phenomenon. Without clear and straightforward communication to pipeline operators about brands of piping and conditions that increase the likelihood of brittle cracking, many pipeline operators may not have the knowledge to make good decisions affecting public safety. Some of these key decisions include how often to conduct leak surveys and whether to repair or replace portions of pipeline systems.

Frequently, piping manufacturers, because they can receive feedback from a number of customers, are the first to learn of systemic problems with their products. For small operators, contact with a manufacturer may be the major source of outside communication about poorly performing products. Unfortunately, while manufacturers have a high degree of technical expertise regarding their products, they may also tend to aggressively publicize the best performance characteristics of their products while only reluctantly acknowledging weaknesses. The Safety Board is aware of only a very few cases in which manufacturers of resin or pipe have formally notified the gas industry of materials having poor resistance to brittle cracking.

Thus, although reputable manufacturers commonly provide essential technical assistance and serve as partners to pipeline operators, operators are still responsible for evaluating and determining which products are most likely to maintain the integrity of their pipeline systems. Furthermore, perhaps because the possibility of premature failure of plastic piping due to brittle-like cracking has not been fully appreciated within the industry and the scope of the potential problem has not been fully measured, the Federal Government has not provided information on this issue to gas system operators. The Safety Board concluded that gas pipeline operators have had insufficient notification that much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s may be susceptible to brittle-like cracking and therefore may not have implemented adequate pipeline surveillance and replacement programs for their older piping.

In the view of the Safety Board, manufacturers of resin and pipe should do more to notify pipeline operators about the poor brittle-crack resistance of some of their past products. The Plastics Pipe Institute (PPI) is the manufacturers' organization that covers most of the major resin and pipe producers, many of whom have manufactured resin and pipe for several years. The Safety Board therefore recommended that the PPI advise its members to notify pipeline system operators if any of their piping products, or materials used in the manufacture of piping products, currently in service for natural gas or other hazardous materials indicate poor resistance to brittle-like failure.

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[17]A number of these experts considered material to have poor resistance to brittle-like cracking if the material was shown to have brittle-like fractures in stress rupture testing at 73 °F before 100,000 hours.

Based on evidence examined by the Safety Board, the premature transition of plastic piping from ductile failures to brittle failures appears to have little observable adverse impact on the serviceability of plastic piping except in those instances in which undamaged piping is subjected to stress intensification generated by external forces. Unfortunately, stress intensification, which can take many forms, has been found in a number of gas piping systems. Rock impingement, soil settlement, and excess pipe bending are among the potential sources of stress intensification, and the combination of piping with poor resistance to brittle-like cracking and external forces can lead to significant rates of failures. These failures can, in turn, lead to serious accidents. The Safety Board therefore concluded that much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s may be susceptible to premature brittle-like failures when subjected to stress intensification, and these failures represent a potential public safety hazard.

Examples of conditions that can generate stress intensification include differential earth settlement, particularly at connections with more rigidly anchored fittings; excessive bending as a result of installation configurations, especially at fittings; and point contact with rocks or other objects. The Safety Board special investigation determined that much of the available guidance to gas system operators for limiting stress intensification at plastic pipeline connections to steel mains is inadequate or ambiguous. Based on its review of this guidance and on the history of the plastic pipeline accidents it has investigated, the Safety Board concluded that, because guidance covering the installation of plastic piping is inadequate for limiting stress intensification at plastic service connections to steel mains, many of these connections may have been installed without adequate protection from shear and bending forces.

Subsequent to the Waterloo accident, personnel from the Iowa Department of Commerce, after discussions with OPS personnel, stated that the Waterloo installation was not in violation of 49 CFR 192.361, which specifies minimum pipeline safety standards for the installation of gas service piping. They further stated that, while they agree that the installation of protective sleeves at pipeline connections is prudent, a specific requirement to install protective sleeves is beyond the scope of Part 192 and is inconsistent with the regulation's performance orientation.

The Transportation Safety Institute (TSI) conducts training classes for Federal and State pipeline inspectors. TSI instructors advise class participants that many of the performance-oriented regulations within Part 192 can only be found to be violated if the gas system fails in a way that demonstrates that the regulation was not followed. The TSI acknowledges the difficulty of identifying violations under paragraph 192.361(d). A TSI instructor told the Safety Board that, in the case of the failed pipe at Waterloo, the installation could not be faulted under Part 192 because of the length of time (23 years) between the installation date and the failure date.

RSPA acknowledges that the regulation that requires gas service lines to be installed so as to minimize anticipated piping strain and external loading lacks performance measurement criteria. The Safety Board pointed out in a previous accident investigation report[18] that, although

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[18]National Transportation Safety Board Pipeline Accident Report, *Kansas Power and Light Company Natural Gas Pipeline Accidents, September 16. 1988 to March 29. 1989* (NTSB/PAR-90/03).

the OPS considers many of its pipeline safety regulations to be performance-oriented requirements, many are no more than general statements of required actions that do not establish any criteria against which the adequacy of the actions taken can be evaluated. The Safety Board has further stated that regulations that do not contain measurable standards for performance make it difficult to determine compliance with the requirement. The Safety Board therefore previously recommended that RSPA:

> Evaluate each of its pipeline safety regulations to identify those that do not contain explicit objectives and criteria against which accomplishment of the objective can be measured; to the extent practical, revise those that are so identified. (P-90-15)

As a result of this safety recommendation, the OPS asked the National Association of Pipeline Safety Representatives liaison committee to review the 20 regulations deemed to be the least enforceable due to lack of clarity. The Safety Board has encouraged RSPA to make such a review a periodic effort so that all of the regulations, not just the specified 20, are continually clarified. The last correspondence to the Safety Board from the OPS regarding this recommendation was on March 8, 1993, and the recommendation has remained classified "Open—Acceptable Response." In an October 31, 1997, letter to the OPS, the Safety Board inquired as to the status of 28 open safety recommendations to RSPA, including P-90-15. The OPS has not yet provided a written response for P-90-15. The Safety Board will continue to follow the progress and urge completion of this recommendation.

Federal regulations require that gas pipeline system operators have in place an ongoing program to monitor the performance of their piping systems. Before the Waterloo accident, Midwest Gas developed only a limited capability for monitoring and analyzing the condition of its gas system. For example, the company did not statistically correlate failure rates to the amounts of installed pipe or components provided by specific manufacturers. The design of the program meant that the relatively few areas with high failure rates (for example, those with Century pipe) were aggregated with and therefore masked by the large number of plastic piping installations that had low failure rates. Thus, the Midwest Gas surveillance program did not reveal the high failure rates associated with Century pipe. Only after the accident did Midwest Gas identify the Century pipe within its pipeline system as having high failure rates, even though the company could have collected and processed the same type of data and reached the same determination before the accident. If Midwest Gas had further correlated its data to years of installation, it may have also been able to examine the effects of its changing installation methods or changes in performance with different manufacturers through the years.

The Safety Board concluded that, before the Waterloo accident, the systems used by Midwest Gas Company for tracking, identifying, and statistically characterizing plastic piping failures did not permit an effective analysis of system failures and leakage history. The Safety Board further concluded that if, before the Waterloo accident, Midwest Gas had had an effective surveillance program that tracked and identified the high leakage rates associated with Century piping when subjected to stress intensification, the company could have implemented a replacement program for the pipe and may have replaced the failed service connection before the accident.

Since the accident, MidAmerican Energy has revised its systems, adding parameters to provide the company with added capability to sort failures. However, MidAmerican Energy has not chosen parameters that will allow an adequate analysis of its plastic piping system failures and leakage history. For example, the generic "improper installation" is a parameter to be linked to leaks; however, no parameters have been added for the presence, lack, improper design, or improper placement of a protective sleeve. And no parameters have been added to link leaks to squeeze locations, improper joining, or items to differentiate between insufficient support and excessive installed bending. The Safety Board therefore concluded that MidAmerican Energy's current systems for tracking, identifying, and statistically characterizing plastic piping failures do not enable an effective analysis of system failures and leakage history.

In a previous accident investigation report,[19] the Safety Board pointed out that many operators had not established procedures to comply with Federal regulations requiring surveillance and investigation of failures. The Safety Board recommended that RSPA:

> Emphasize, as a part of OPS inspections and during training and state monitoring programs, the actions expected of gas operators to comply with the continuing surveillance and failure investigation, including laboratory examination requirements. (P-90-14)

In a letter to the Safety Board, RSPA responded that the TSI had increased emphasis on gas surveillance and failure investigation in the operations block of its industry seminars held across the country. The letter stated that the TSI would incorporate a discussion of accident analysis into a new hazardous liquids seminar that was to be presented for the first time in FY 1992. Additionally, RSPA noted that it planned to place additional emphasis on continuing surveillance and failure investigation requirements in its new inspection forms at the time of the next revision. Based on this response, the Safety Board classified Safety Recommendation P-90-14 "Closed—Acceptable Action."

Despite the RSPA response to this safety recommendation, for a variety of reasons—including the inadequate performance monitoring programs found at Midwest Gas/MidAmerican Energy, the susceptibility to brittle cracking of much of the polyethylene piping installed through the early 1980s, deficiencies noted in gas industry communications regarding poorly performing brands of polyethylene piping, and differences noted in the performance of different types and brands of polyethylene piping—RSPA may need to do more. Gas system operators may need to be advised once again of the importance of complying with Federal requirements for piping system surveillance and analyses. As is the case with older piping, an effective plastic pipeline surveillance program would be based on factors such as piping manufacturer, installation date, pipe diameter, operating pressure, leak history, geographical location, modes of failure (such as bending,

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[19] National Transportation Safety Board Pipeline Accident Report--*Kansas Power and Light Company Natural Gas Pipeline Accidents, September 16, 1988, to March 29, 1989.*

inadequate support, rock impingement, or improper joining), location of failure (such as at the main to service or at pipe squeeze locations), and other factors such as the presence, absence, or misapplication of a sleeve. An effective program would also evaluate past piping and components installed, as well as past installation practices, to provide a basis for the replacement, in a planned, timely manner, of plastic piping systems that indicate unacceptable performance.

The expressed purpose of RSPA's *Guidance Manual for Operators of Small Natural Gas Systems* is to assist nontechnically trained persons who operate small gas systems. However, the manual provides no caution against bending close to a plastic service connection to a steel main. The manual recommends following manufacturers' instructions and indicates that a properly designed sleeve should be used at this connection, which would address designing the sleeve with the proper diameter and length. However, none of the steel tapping tee manufacturers has recommended precautions to limit stresses at the service to main connection; therefore, nontechnically trained persons may not realize the importance of determining these parameters.

The National Transportation Safety Board therefore makes the following safety recommendations to the Research and Special Programs Administration:

> Notify pipeline system operators who have installed polyethylene gas piping extruded by Century Utility Products, Inc., from Union Carbide Corporation DHDA 2077 Tan resin of the piping's poor brittle-crack resistance. Require these operators to develop a plan to closely monitor the performance of this piping and to identify and replace, in a timely manner, any of the piping that indicates poor performance based on such evaluation factors as installation, operating, and environmental conditions; piping failure characteristics; and leak history. (P-98-1)
>
> Determine the extent of the susceptibility to premature brittle-like cracking of older plastic piping (beyond that piping marketed by Century Utility Products, Inc.) that remains in use for gas service nationwide. Inform gas system operators of the findings and require them to closely monitor the performance of the older plastic piping and to identify and replace, in a timely manner, any of the piping that indicates poor performance based on such evaluation factors as installation, operating, and environmental conditions; piping failure characteristics; and leak history. (P-98-2)
>
> Immediately notify those States and territories with gas pipeline safety programs of the susceptibility to premature brittle-like cracking of much of the plastic piping manufactured from the 1960s through the early 1980s and of the actions that the Research and Special Programs Administration will require of gas system operators to monitor and replace piping that indicates unacceptable performance. (P-98-3)
>
> In cooperation with the manufacturers of products used in the transportation of gases or liquids regulated by the Office of Pipeline Safety, develop a mechanism by which the Office of Pipeline Safety will receive copies of all safety-related notices, bulletins, and other communications regarding any defect, unintended

deviation from design specification, or failure to meet expected performance of any piping or piping product that is now in use or that may be expected to be in use for the transport of hazardous materials. (P-98-4)

Revise the *Guidance Manual for Operators of Small Natural Gas Systems* to include more complete guidance for the proper installation of plastic service pipe connections to steel mains. The guidance should address pipe bending limits and should emphasize that a protective sleeve, in order to be effective, must be of the proper length and inner diameter for the particular connection and must be positioned properly. (P-98-5)

Also, the National Transportation Safety Board issued Safety Recommendations P-98-6 to the Gas Research Institute; P-98-7 through -9 to the Plastics Pipe Institute; P-98-10 to the Gas Piping Technology Committee; P-98-11 and -12 to the American Society for Testing and Materials; P-98-13 to the American Gas Association; P-98-14 and -15 to MidAmerican Energy Corporation; P-98-16 and -17 to Continental Industries, Inc.; P-98-18 to Dresser Industries, Inc.; P-98-19 to Inner-Tite Corporation; and P-98-20 to Mueller Company.

Please refer to Safety Recommendations P-98-1 through -5 in your reply. If you need additional information, you may call (202) 314-6469

Chairman HALL, Vice Chairman FRANCIS, and Members HAMMERSCHMIDT, GOGLIA, and BLACK concurred in these recommendations.

By: Jim Hall
Chairman

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 4

Sept. 1, 1999 Dept of Transportation Potential Failure Due to Brittle-Like Cracking Certain Polyethylene Plastic Pipe Manufactured by Century Utility Products, Inc.

ADB-99-01

Sep 1, 1999

Billing Code: 4910-60-P
DEPARTMENT OF TRANSPORTATION
Pipeline and Hazardous Materials Safety Administration

Potential Failure Due to Brittle-Like Cracking Certain Polyethylene Plastic Pipe Manufactured by Century Utility Products Inc.

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice; issuance of advisory bulletin on Century polyethylene gas pipe to owners and operators of natural gas distribution systems.

SUMMARY: This advisory bulletin is directed at owners and operators of natural gas distribution systems that have installed plastic pipe extruded by Century Utility Products Inc. from Union Carbide Corporation's DHDA 2077 Tan medium density polyethylene resin (Century pipe). Pipe manufactured between 1970 and 1973 may fail in service due to its poor resistance to brittle-like cracking. Operators with Century pipe in their systems should closely monitor this pipe for leaks with increased leak survey frequency. Century pipe that may be improperly installed, repaired, or operating in an environment that impairs pipe strength should be replaced.

ADDRESS: This document can be viewed on the Office of Pipeline Safety (OPS) home page at: http://ops.dot.gov.

FOR FURTHER INFORMATION CONTACT: Gopala (Krishna) Vinjamuri at (202) 366- 4503, or by E-mail at vinjamuri@PHMSA.dot.gov.

SUPPLEMENTARY INFORMATION:

I. Background

The National Transportation Safety Board (NTSB) recently published the results of a special investigation into accidents that involved plastic pipe currently in use to deliver natural gas to residential and business use. The report, Brittle-Like Cracking in Plastic Pipe for Gas Service (NTSB/SIR-98/01; April 23, 1998) suggested that "[d]espite the general acceptance of plastic piping as a safe and economical alternative to piping made of steel and other materials, [a] number of pipeline accidents investigated have involved plastic piping that cracked in a brittle-like manner." Copies of this report may be obtained from NTSB Public Inquiry Office by calling 202-314-6551.

The phenomenon of brittle-like cracking in plastic pipe as described in the NTSB report and generally understood within the plastic pipeline industry relates to a part-through crack initiation in the pipe wall followed by stable crack growth at stress levels much lower than the stress required for yielding, resulting in a very tight slit-like opening and gas leak. This failure mode is difficult to detect until significant amount of gas leaks out of the pipe, and potentially migrates into closed space such as basements of dwellings. Premature brittle-like cracking requires relatively high localized stress intensification that may be a result from geometrical discontinuities, excessive bending, improper fitting assemblies, and/or dents and gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the failure results in fragmentation of the pipe.

NTSB also alleged that the guidance provided by manufacturers and industry standards for the installation of plastic pipe is inadequate for limiting stress intensification, particularly at plastic service connections to steel mains, many of these connections may have been installed without adequate protection from shear and bending forces that may result in brittle-like cracking.

Century pipe

Between 1970 and 1973, Century Utility Products Inc. (a/k/a AMDEVCO), now defunct, marketed medium density polyethylene plastic pipe and fittings (Century pipe) in sizes ranging from ½ inch to 4 inches for use in natural gas distribution. These plastic pipes and fittings were manufactured by extrusion from Union Carbide Corporation's DHDA 2077 Tan resin, and was marked PE 2306 in accordance with American Society for Testing and Materials (ASTM) standards. Following investigation of a series of incidents, including the December 2, 1979, explosion in a residence in Tuscola, Illinois, and the October 17, 1994, accident in Waterloo, Iowa, that resulted in several fatalities, it was established that the

Union Carbide's DHDA 2077 Tan resin lacks adequate resistance to brittle-like cracking and is prone to relatively short life when subjected to high local stress concentration. The pipe in the Tuscola, Illinois, accident failed in less than 8 years, and the pipe in the Waterloo, Iowa, accident failed within 23 years in service. It has been established that Century pipe exhibited significantly higher leak rate in comparison with other polyethylene, steel, and cast iron pipe used in natural gas distribution systems.

Following the Waterloo, Iowa, accident, PHMSA has taken number of actions, including gathering Century pipe installation data. Also, remedial action has been taken by various operators in mid-western states where much of the Century pipe produced was known to have been installed. It is PHMSA's understanding that the operators having Century pipe in their systems have initiated close monitoring and some have replacement program in progress.

NTSB recommended that PHMSA notify owners and operators of natural gas systems who continue to use Century pipe of the potential for premature failures by brittle-like cracking and the need to "[d]evelop a plan to closely monitor the performance of and to identify and replace, in a timely manner, any piping that indicates poor performance based on such evaluation factors as installation, operating and environmental conditions, piping failure characteristics and leak history."

II. Advisory Bulletin (ADB-99-01)

To: Owners and Operators of Natural Gas Distribution Pipeline Systems

Subject: Susceptibility of certain polyethylene pipe manufactured by Century Utility Products Inc. to premature failure due to brittle-like cracking.

Purpose: To advise natural gas distribution pipeline owners and operators of the need to closely monitor and replace as necessary polyethylene natural gas pipe manufactured by Century Utility Products Inc. between 1970 and 1973 that is susceptible to brittle-like cracking.

Advisory: All owners and operators of natural gas distribution systems who have installed and continue to use polyethylene pipe extruded by Century Utility Products Inc, (now defunct) from the resin DHDA 2077 Tan resin manufactured by Union Carbide Corporation during the period 1970 to 1973 (Century pipe) are advised that this pipe may be susceptible to premature failure due to brittle-like cracking. Premature failures by brittle-like cracking of Century pipe is known to occur due to poor resin characteristics, excessive local stress intensification caused by improper joints, improper installation, and environments detrimental to pipe long-term strength. All distribution systems containing Century pipe should be monitored to identify pipe subject to brittle-like cracking. Remedial action, including replacement, should be taken to protect system integrity and public safety.

In addition, in light of the potential susceptibility of Century pipe to brittle-like cracking, PHMSA recommends that each natural gas distribution system operator with Century pipe revise their plastic pipe repair procedure(s) to exclude pipe pinching for isolating sections of Century pipe. Additionally, PHMSA recommends replacement of any Century pipe segment that has a significant leak history or which for any reason is of suspect integrity.

(49 U.S.C. Chapter 601; 49 CFR 1.53)

Issued in Washington, D.C. on ____________________.

Richard B. Felder

Associate Administrator for Pipeline Safety

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 5

Advisory Bulletin (ADB-02-7) Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe

Advisory Bulletin (ADB-02-7)

[Notices][Page 70806-70808]
Billing Code: 4910-60-P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe.

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice; issuance of advisory bulletin.

SUMMARY. RSPA is issuing this follow-up advisory bulletin to owners and operators of natural gas distribution systems to inform them of the susceptibility to premature brittle-like cracking of older plastic pipe and the voluntary efforts to collect and analyze data on plastic pipe performance. A Special Investigation Report issued by the National Transportation Safety Board (NTSB) described how plastic pipe installed in natural gas distribution systems from the 1960s through the early 1980s may be vulnerable to brittle-like cracking resulting in gas leakage and potential hazards to the public and property. On March 11, 1999, RSPA issued two advisory bulletins on this issue. The first bulletin reminded natural gas distribution system operators of the potential poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc. The second bulletin advised natural gas distribution system operators of the potential vulnerability of older plastic pipe to brittle-like cracking.

ADDRESS: This document can be viewed on the Office of Pipeline Safety (OPS) home page at: http://ops.dot.gov.

FOR FURTHER INFORMATION CONTACT: Gopala K. Vinjamuri, (202) 366-4503, or by email at gopala.vinjamuri@rspa.dot.gov.

SUPPLEMENTARY INFORMATION

I. Background

On April 23, 1998, NTSB issued a Special Investigation Report (NTSB/SIR-98/01), Brittle-like Cracking in Plastic Pipe for Gas Service, that describes how plastic pipe installed in natural gas distribution systems from the 1960s through the early 1980s may be vulnerable to brittle-like cracking resulting in gas leakage and potential hazards to the public and property. An NTSB survey of the accident history of plastic pipe suggested that the material may be susceptible to premature brittle-like cracking under conditions of local stress intensification because of improper joining or installation procedures. Hundreds of thousands of miles of plastic pipe have been installed, with a significant amount installed prior to the early-1980s. NTSB believes any vulnerability of this material to premature cracking could represent a potentially serious hazard to public safety. Copies of this report may be obtained by calling NTSB's Public Inquiry Office at 202-314-6551.

RSPA has already issued two advisory bulletins on this issue. The first advisory bulletin, ADB-99-O1, which was published in the Federal Register on March 11, 1999 (47 FR 12211), reminded natural gas distribution system operators of the potential poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc. The second advisory bulletin, ADB99-02, also published in the Federal Register on March 11, 1999 (47 FR 12212), advised natural gas distribution system operators of the potential brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s.

The phenomenon of brittle-like cracking in plastic pipe as described in the NTSB report and generally understood within the plastic pipeline industry relates to a part-through crack initiation in the pipe wall followed by stable crack growth at stress levels much lower than the stress required for yielding, resulting in a very tight slit-like openings and gas leaks. Although significant cracking may occur at points of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement. Premature brittle-like cracking requires relatively high localized stress intensification that may be a result from geometrical discontinuities, excessive bending, improper installation of fittings, and dents and gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the pipe failure causes in fragmentation of the pipe.

The NTSB report suggests that the combination of more durable plastic pipe materials and more realistic strength testing has improved the reliability of estimates of the long-term hydrostatic strength of modern plastic pipe and fittings. The report also documents that older polyethylene pipe, manufactured from the 1960s through the early 1980s, may fail at lower stresses and after less time than was originally projected. NTSB alleges that past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.

In 1998, NTSB made several recommendations to trade organizations and to RSPA on the need for a better understanding of the susceptibility of plastic pipe to brittle-like cracking. This advisory bulletin responds to one of the NTSB recommendations. It is that RSPA "[d]etermine the extent of the susceptibility to premature brittle-like cracking of older plastic piping (beyond that marketed by Century Utilities Products Inc.) that remains in use for gas service nationwide. Inform gas system operators of the findings and require them to closely monitor the performance of the older plastic piping and to identify and replace, in a timely manner, any of the piping that indicates poor performance based on such evaluation factors as installation, operating, and environmental conditions; piping failure characteristics; and leak history."

In order to obtain the most complete information on the extent of the susceptibility to premature brittlelike cracking of older plastic pipe, a meeting was convened in May 1999 with all the stakeholders to determine how information on older plastic pipe could be assembled. The meeting included representatives of the American Gas Association (AGA), the American Public Gas Association (APGA), the Gas Research Institute (GRI) (now the Gas Technology Institute), the Midwest Energy Association (MEA), and the Plastic Pipe Institute (PPI).

As a result of the May 1999 meeting, the Joint Government-Industry Plastic Pipe Study Committee was formed to address the recommendations of the NTSB Special Investigation Report. The committee held three separate meetings to prepare a draft response to the NTSB recommendations and a draft industry notification of brittle-like cracking problems, the subject of this advisory bulletin. The committee membership consisted of a representative from OPS, a gas distribution operator from AGA, and the Transportation Safety Institute. Meetings were facilitated by General Physics Corporation, Columbia, MD. One of the committee findings was that there is a lack of data available from the industry to completely identify older plastic pipe that is still in service and may be susceptible to brittle-like cracking.

This finding led to the formation of the Plastic Pipe Database Committee (PPDC) to develop a process for gathering data on future plastic pipe failures with involvement from the states, which have assumed the authority from OPS over gas distribution systems, where most of the plastic pipe is installed. The PPDC is comprised of representatives from Federal and State regulatory agencies and from the natural gas and plastic pipe industries. Members include AGA, APGA, PPI, the National Association of Regulatory Utility Commissioners (NARUC), the National Association of Pipeline Safety Representatives (NAPSR), and OPS.

The PPDC database is expected to improve the knowledge base of gas utility operators and regulators and is intended to help reveal any failure trends associated with older plastic piping materials. The PPDC's mission is "to develop and maintain a voluntary data collection process that supports the analysis of the frequency and causes of in-service plastic piping material failures." It provides an opportunity for government and industry to work together to evaluate the extent of plastic pipe performance problems and to mitigate any risks to safety. The PPDC started gathering data in January 2001 from OPS and State pipeline safety agencies. For more information on the PPDC, go to the AGA web page (www.aga.org), and enter "PPDC" in the keyword search.

II. Advisory Bulletin (ADB-02-7)

To: Owners and Operators of Natural Gas Distribution Pipeline Systems

Subject: Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe.

Advisory: In recent years, brittle-like cracking has been observed in some polyethylene pipes installed in gas service through the early 1980s. This brittle-like cracking (also known as slow crack growth) can substantially reduce the service life of polyethylene piping systems.

The susceptibility of some polyethylene pipes to brittle-like cracking is dependent on the resin, pipe processing, and service conditions. A number of studies have been conducted on older polyethylene

pipe. These studies have shown that some of these older polyethylene pipes are more susceptible to brittle-like cracking than current materials. These older polyethylene pipe materials include the following:

· Century Utility Products, Inc. products.

· Low-ductile inner wall "Aldyl A" piping manufactured by Dupont Company before 1973.

· Polyethylene gas pipe designated PE 3306. (As a result of poor performance this designation was removed from ASTM D-2513.)

The environmental, installation, and service conditions under which the piping is used are factors that could lead to premature brittle-like cracking of these older materials. These conditions include, but are not limited to:

· Inadequate support and backfill during installation

· Rock impingement

· Shear/bending stresses due to differential settlement resulting from factors such as:

o Excavation in close proximity to polyethylene piping o Directional drilling in close proximity to polyethylene piping

o Frost heave

· Bending stresses due to pipe installations with bends exceeding recommended practices

· Damaging squeeze-off practices

Service temperatures and service pressures also influence the service life of polyethylene piping. Piping installed in areas with higher ground temperatures or operated under higher operating pressures will have a shorter life.

Gas system operators may experience an increase in failure rates with a susceptible material. A susceptible material may have leak-free performance for a number of years before brittle-like cracks occur. An increase in the occurrence of leaks will typically be the first indication of a brittle-like cracking problem. It is the responsibility of each pipeline operator to monitor the performance of their gas system. RSPA issues the following recommendations to aid operators in identifying and managing brittle-like cracking problems in polyethylene piping involving taking appropriate action, including replacement, to mitigate any risks to public safety.

Because systems without known susceptible materials may also experience brittle-like cracking problems, RSPA recommends that all operators implement the following practices for all polyethylene piping systems:

1. Review system records to determine if any known susceptible materials have been installed in the system. Both engineering and purchasing records should be reviewed. Based on the available records, identify the location of the susceptible materials. More frequent inspection and leak surveys should be performed on systems that have exhibited brittle-like cracking failures of known susceptible materials.

2. Establish a process to identify brittle-like cracking failures. Identification of failure types and site installation conditions can yield valuable information that can be used in predicting the performance of the system.

3. Use a consistent record format to collect data on system failures. The AGA Plastic Failure Report form (Appendix F of the AGA Plastic Pipe Manual) provides an example of a report for the collection of failure data.

4. Collect failure samples of polyethylene piping exhibiting brittle-like cracking. Evidence of brittle-like cracking may warrant laboratory testing. Although every failure may not warrant testing, collecting samples at the time of

failure would provide the opportunity to conduct future testing should it be deemed necessary.

5. Whenever possible record the print line from any piping that has been involved in a failure. The print line information can be used to identify the resin, manufacturer and year of manufacture for plastic piping.

6. For systems where there is no record of the piping material, consider recording print line data when piping is excavated for other reasons. Recording the print line data can aid in establishing the type and extent of polyethylene piping used in the system.

(49 U.S.C. chapter 601; 49 CFR 1.53)
Issued in Washington, DC, on November 21, 2002.

Stacey L. Gerard
Associate Administrator for Pipeline Safety.

[FR Doc. 02-30055 Filed 11-25-02; 8:45 am]

Advisory Bulletin (ADB-02-7) - Correction

[Notices][Page 72027]

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice; correction.

SUMMARY: In the Federal Register of November 26, 2002, (67 FR 70806) the Research and Special Programs Administration (RSPA) published a notice document issuing an advisory bulletin on the susceptibility to premature brittle-like cracking of older plastic pipe (ADB-02-7). RSPA is submitting this correction notice to reflect minor wording changes and include a website address.

EFFECTIVE DATE: This correction takes effect November 26, 2002.

FOR FURTHER INFORMATION CONTACT: Gopala K. Vinjamuri, (202) 366-4503, or by email at gopala.vinjamuri@rspa.dot.gov.

SUPPLEMENTARY INFORMATION:

Correction

The last sentence in the first paragraph of the Supplementary Information heading under I. Background, reads:

Copies of this report may be obtained by calling NTSB's Public Inquiry Office at 202-314-6551.

We are revising this sentence to add NTSB's website address. The sentence is revised to read as follows:

Copies of this report may be obtained by calling NTSB's Public Inquiry Office at 202-314-6551, or on the NTSB website at www.ntsb.gov.

In the fourth paragraph under SUPPLEMENTARY INFORMATION, the first sentence reads:

The NTSB report suggests that .... Remove the word ``suggests'' and replace with the word ``states''.

In the fourth paragraph under Supplementary Information, the third sentence reads:

NTSB alleges that .... Remove the word ``alleges'' and replace with the word ``concluded''.

Under II. Advisory Bulletin (ADB-02-7) of the SUPPLEMENTARY INFORMATION heading, in the second paragraph under Advisory. The fourth sentence reads:

These older polyethylene pipe materials include the following:

The sentence is revised to read as follows:

These older polyethylene pipe materials include, but are not limited to:

Issued in Washington, DC on November 27, 2002.
James K. O'Steen,
Deputy Associate Administrator for Pipeline Safety.
[FR Doc. 02-30615 Filed 12-2-02; 8:45 am]

BILLING CODE 4910-60-P

Advisory Bulletin ADB-99-01

[Notices] [Page 12211-12212]

DEPARTMENT OF TRANSPORTATION
Research and Special Programs Administration

Potential Failure Due to Brittle-Like Cracking Certain Polyethylene Plastic Pipe Manufactured by Century Utility Products Inc

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice; issuance of advisory bulletin on Century polyethylene gas pipe to owners and operators of natural gas distribution systems.

SUMMARY: This advisory bulletin is directed at owners and operators of natural gas distribution systems that have installed plastic pipe extruded by Century Utility Products Inc. from Union Carbide Corporation's DHDA 2077 Tan medium density polyethylene resin (Century pipe). Pipe manufactured between 1970 and 1973 may fail in service due to its poor resistance to brittle-like cracking. Operators with Century pipe in their systems should closely monitor this pipe for leaks with increased leak survey frequency. Century pipe that may be improperly installed, repaired, or operating in an environment that impairs pipe strength should be replaced.

ADDRESSES: This document can be viewed on the Office of Pipeline Safety (OPS) home page at: http://ops.dot.gov.

FOR FURTHER INFORMATION CONTACT: Gopala (Krishna) Vinjamuri at (202) 366-4503, or by E-mail at vinjamuri@rspa.dot.gov.

SUPPLEMENTARY INFORMATION:
I. Background

The National Transportation Safety Board (NTSB) recently published the results of a special investigation into accidents that involved plastic pipe currently in use to deliver natural gas to residential and business use. The report, Brittle-Like Cracking in Plastic Pipe for Gas Service (NTSB/SIR-98/01; April 23, 1998) suggested that "[d]espite the general acceptance of plastic piping as a safe and economical alternative to piping made of steel and other materials, [a] number of pipeline accidents investigated have involved plastic piping that cracked in a brittle-like manner." Copies of this report may be obtained from NTSB Public Inquiry Office by calling 202-314-6551.

The phenomenon of brittle-like cracking in plastic pipe as described in the NTSB report and generally understood within the plastic pipeline industry relates to a part-through crack initiation in the pipe wall followed by stable crack growth at stress levels much lower than the stress required for yielding, resulting in a very tight slit-like opening and gas leak. This failure mode is difficult to detect until significant amount of gas leaks out of the pipe, and potentially migrates into closed space such as basements of dwellings. Premature brittle-like cracking requires relatively high localized stress intensification that may be a result from geometrical discontinuities, excessive bending, improper fitting assemblies, and/or dents and gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the failure results in fragmentation of the pipe.

NTSB also alleged that the guidance provided by manufacturers and industry standards for the installation of plastic pipe is inadequate for limiting stress intensification, particularly at plastic service connections to steel mains, many of these connections may have been installed without adequate protection from shear and bending forces that may result in brittle-like cracking.

Century Pipe
Between 1970 and 1973, Century Utility Products Inc. (a/k/a AMDEVCO), now defunct, marketed medium density polyethylene plastic pipe and fittings (Century pipe) in sizes ranging from \1/2\ inch to 4 inches for use in natural gas distribution. These plastic pipes and fittings were manufactured by extrusion from Union Carbide Corporation's DHDA 2077 Tan resin, and was marked PE 2306 in accordance with American Society for Testing and Materials (ASTM) standards. Following investigation of a series of incidents, including the December 2, 1979, explosion in a residence in Tuscola, Illinois, and the October 17, 1994, accident in Waterloo, Iowa, that resulted in several fatalities, it was established that the Union Carbide's DHDA 2077 Tan resin lacks adequate resistance to brittle-like cracking and is prone to relatively short life when subjected to high local stress concentration. The pipe in the Tuscola, Illinois, accident failed in less than 8 years, and the pipe in the Waterloo, Iowa, accident failed within 23 years in service. It has been established that Century pipe exhibited significantly higher leak rate in comparison with other polyethylene, steel, and cast iron pipe used in natural gas distribution systems.

Following the Waterloo, Iowa, accident, RSPA has taken number of actions, including gathering Century pipe installation data. Also, remedial action has been taken by various operators in mid-western states where much of the Century pipe produced was known to have been installed. It is RSPA's understanding that the operators having Century pipe in their systems have initiated close monitoring and some have replacement program in progress.

NTSB recommended that RSPA notify owners and operators of natural gas systems who continue to use Century pipe of the potential for premature failures by brittle-like cracking and the need to "[d]evelop a plan to closely monitor the performance of and to identify and replace, in a timely manner, any piping that indicates poor performance based on such evaluation factors as installation, operating and environmental conditions, piping failure characteristics and leak history."

II. Advisory Bulletin (ADB-99-01)

To: Owners and Operators of Natural Gas Distribution Pipeline Systems.

Subject: Susceptibility of certain polyethylene pipe manufactured by Century Utility Products Inc. to premature failure due to brittle-like cracking.

Purpose: To advise natural gas distribution pipeline owners and operators of the need to closely monitor and replace as necessary polyethylene natural gas pipe manufactured by Century Utility Products Inc. between 1970 and 1973 that is susceptible to brittle-like cracking.

Advisory: All owners and operators of natural gas distribution systems who have installed and continue to use polyethylene pipe extruded by Century Utility Products Inc, (now defunct) from the resin DHDA 2077 Tan resin manufactured by Union Carbide Corporation during the period 1970 to 1973 (Century pipe) are advised that this pipe may be susceptible to premature failure due to brittle-like cracking. Premature failures by brittle-like cracking of Century pipe is known to occur due to poor resin characteristics, excessive local stress intensification caused by improper joints, improper installation, and environments detrimental to pipe long-term strength. All distribution systems containing Century pipe should be monitored to identify pipe subject to brittle-like cracking. Remedial action, including replacement, should be taken to protect system integrity and public safety.

In addition, in light of the potential susceptibility of Century pipe to brittle-like cracking, RSPA recommends that each natural gas distribution system operator with Century pipe revise their plastic pipe repair procedure(s) to exclude pipe pinching for isolating sections of Century pipe. Additionally, RSPA recommends replacement of any Century pipe segment that has a significant leak history or which for any reason is of suspect integrity.

Authority: 49 U.S.C. Chapter 601; 49 CFR 1.53.

Issued in Washington, DC on March 5, 1999.
Richard B. Felder,
Associate Administrator for Pipeline Safety.
[FR Doc. 99-6013 Filed 3-10-99; 8:45 am]
BILLING CODE 4910-60-P

Advisory Bulletin ADB-99-02

[Notices][Page 12212-12213]

DEPARTMENT OF TRANSPORTATION
Research and Special Programs Administration

Potential Failures Due to Brittle-Like Cracking of Older Plastic Pipe in Natural Gas Distribution Systems

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice; issuance of advisory bulletin on brittle-like failures of plastic pipe to owners and operators of natural gas distribution systems.

SUMMARY: RSPA is issuing this advisory bulletin to owners and operators of natural gas distribution systems to inform them of the potential vulnerability of older plastic gas distribution pipe to brittle-like cracking. The National Transportation Safety Board (NTSB) recently issued a Special Investigation Report (NTSB/SIR-98/01), Brittle-like Cracking in Plastic Pipe for Gas Service, that described how plastic pipe installed in natural gas distribution systems from the 1960s through the early 1980s may be vulnerable to brittle-like cracking resulting in gas leakage and potential hazards to the public and property. RSPA has also issued an additional advisory bulletin (ADB-99-01) reminding natural gas distribution system operators of the potential poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc.

ADDRESSES: This document can be viewed on the Office of Pipeline Safety (OPS) home page at: http://ops.dot.gov.

FOR FURTHER INFORMATION CONTACT: Gopala K. Vinjamuri, (202) 366-4503, or by email at gopala.vinjamuri@rspa.dot.gov.

SUPPLEMENTARY INFORMATION:
I. Background

The National Transportation Safety Board (NTSB) recently issued a Special Investigation Report (NTSB/SIR-98/01), Brittle-like Cracking in Plastic Pipe for Gas Service, that described how plastic pipe installed in natural gas distribution systems from the 1960s through the early 1980s may be vulnerable to brittle-like cracking resulting in gas leakage and potential hazards to the public and property. An NTSB survey of the accident history of plastic pipe suggested that the material may be susceptible to premature brittle-like cracking under conditions of local stress intensification because of improper joining or installation procedures. Hundreds of thousands of miles of plastic pipe have been installed, with a significant amount installed prior to the mid-1980s. NTSB believes any vulnerability of this material to premature failure could represent a potentially serious hazard to public safety.

The NTSB report addressed the following safety issues:

· The vulnerability of plastic pipe to premature failures due to brittle-like cracking;

· The adequacy of available guidance relating to the installation and protection of plastic pipe connections to steel mains; and

· Performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems.

Copies of this report may be obtained by calling NTSB's Public Inquiry Office at 202-314-6551.

The phenomenon of brittle-like cracking in plastic pipe as described in the NTSB report and generally understood within the plastic pipeline industry relates to a part-through crack initiation in the pipe wall followed by stable crack growth at stress levels much lower than the stress required for yielding, resulting in a very tight slit-like opening and gas leak. Although significant cracking may occur at points of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement. Premature brittle-like cracking requires relatively high localized stress intensification that may be a result from geometrical discontinuities, excessive bending, improper fitting assemblies, and/or dents and gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the failure results in fragmentation of the pipe.

The report suggests that the combination of more durable plastic pipe materials and more realistic strength testing has improved the reliability of estimates of the long-term hydrostatic strength of modern plastic pipe and fittings. The report also documents that older polyethylene pipe, manufactured from the 1960s through the early 1980s, may fail at lower stresses and after less time than was originally projected. NTSB alleges that past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.

In 1998, NTSB made several recommendations to trade organizations and to the Research and Special Programs Administration (RSPA) on the need for a better understanding of the susceptibility of plastic pipe to brittle-like cracking. NTSB recommended that RSPA "[d]etermine the extent of the susceptibility to premature brittle-like cracking of older plastic piping (beyond that marketed by Century Utilities Products Inc.) that remains in use for gas service nationwide."

II. Advisory Bulletin (ADB-99-02)

To: Owners and Operators of and Natural Gas Distribution Pipeline Systems

Subject: Potential susceptibility of plastic pipe installed between the 1960 and the early 1980s to premature failure due to brittle-like cracking.

Purpose: To inform natural gas distribution pipeline operators of the need to determine the extent of susceptibility to brittle-like cracking of plastic pipe installed between the years 1960 and early 1980s.

Advisory: A review of Office of Pipeline Safety (OPS) reportable natural gas pipeline incidents and the findings of NTSB Special Investigation Report (NTSB/SIR-98/01) indicates that certain plastic pipe used in natural gas distribution service may be susceptible to brittle-like cracking. The standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.

It is recommended that all owners and operators of natural gas distribution systems identify all pre-1982 plastic pipe installations, analyze leak histories, and evaluate any conditions that may impose high stresses on the pipe. Appropriate remedial action, including replacement, should be taken to mitigate any risks to public safety.

Authority: 49 U.S.C. Chapter 601; 49 CFR 1.53.
Issued in Washington, D.C. on March 3, 1999.
Richard B. Felder,
Associate Administrator for Pipeline Safety.

[FR Doc. 99-6051 Filed 3-10-99; 8:45 am]
BILLING CODE 4910-60-P

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 6

September 6, 2007
Federal Register Vol. 72, No. 172
Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

safety procedures used for filling, operating, and discharging MATs to determine whether additional safety procedures should be implemented. To this end, we request that persons who use such transportation systems to provide us with information on the effectiveness of the current DOT regulations, consensus standards, and industry best practices. We are also interested in any other procedures utilized to ensure that operations related to the transportation of acetylene on MATs are performed safely.

We would also like to work with shippers, carriers, and facilities that receive shipments of acetylene in MATs to develop and implement a pilot program to test the effectiveness of current or alternative procedures or methods designed to enhance the safety of transportation operations involving acetylene on MATs. As part of this program, we will assist individual companies or facilities to evaluate the effectiveness of their current procedures and to identify additional measures that should be implemented. We welcome suggestions concerning how such a program should be structured and the entities that should participate.

To ensure that our message reaches all stakeholders affected by these risks, we plan to communicate this advisory through our public affairs notification and outreach processes. For additional visibility, we have made this advisory available on the PHMSA homepage at *http://www.phmsa.dot.gov* and the DOT electronic docket site at *http://dms.dot.gov*. In addition, if you are aware of other companies that are involved in the charging, operating, and discharging MATs, please share this advisory notice with them and, if possible, identify them in your correspondence with this agency. We believe a collaborative effort involving an integrated and cooperative approach will help us to address safety risks, reduce incidents, enhance safety, and protect the public.

Issued in Washington, DC on August 30, 2007.

Theodore L. Willke,

Associate Administrator for Hazardous Materials Safety.

[FR Doc. 07–4355 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2004–19856]

Pipeline Safety: Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this updated advisory bulletin to owners and operators of natural gas pipeline distribution systems concerning the susceptibility of older plastic pipe to premature brittle-like cracking. PHMSA previously issued three advisory bulletins on this subject: Two on March 11, 1999 and one on November 26, 2002. This advisory bulletin expands on the information provided in the three prior bulletins by listing two additional pipe materials with poor performance histories relative to brittle-like cracking and by updating pipeline owners and operators on the ongoing voluntary efforts to collect and analyze data on plastic pipe performance. Owners and operators of natural gas pipeline distribution systems are encouraged to review the three previous advisory bulletins in their entirety.

FOR FURTHER INFORMATION CONTACT: Richard Sanders at (405) 954–7214, or by e-mail at *richard.sanders@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. National Transportation Safety Board (NTSB) Investigation

On April 23, 1998, the National Transportation Safety Board (NTSB) issued its Special Investigation Report, *Brittle-Like Cracking in Plastic Pipe for Gas Service,* NTSB/SIR–98/01. The report described the results of the NTSB's special investigation of polyethylene gas service pipe, which addressed three major safety issues: (1) Vulnerability of plastic piping to premature failures due to brittle-like cracking; (2) adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains; and, (3) effectiveness of performance monitoring of plastic pipeline systems to detect unacceptable performance in piping systems.

(1) *Vulnerability of plastic piping to premature failures due to brittle-like cracking:* The NTSB found that failures in polyethylene pipe in actual service are frequently brittle-like, slit failures, not ductile failures. It concluded the number and similarity of plastic pipe accident and non-accident failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s. The NTSB also concluded any potential public safety hazards from these failures are likely to be limited to locations where stress intensification exists. The NTSB went on to state that more durable modern plastic piping materials and better strength testing have made the strength ratings of modern plastic piping more reliable.

(2) *Adequacy of available guidance relating to the installation and protection of plastic piping connections to steel mains:* The NTSB concluded that gas pipeline operators had insufficient notification of the brittle-like failure potential for plastic pipe manufactured and used for gas service from the 1960s to the early 1980s. The NTSB also concluded this may not have allowed companies to implement adequate surveillance and replacement programs for older plastic piping. The NTSB explained the Gas Research Institute (GRI) developed a significant amount of data on older plastic pipe but the data was published in codified terms making it insufficient for use by pipeline system operators. The NTSB recommended that manufacturers of resin and pipe, industry trade groups and the Federal government do more to alert pipeline operators to the role played by stress intensification from external forces in the premature failure of plastic pipe due to brittle-like cracking.

(3) *Effectiveness of performance monitoring of plastic pipeline systems as a way of detecting unacceptable performance in piping systems:* The NTSB's analysis noted that Federal regulations require pipeline operators to have an ongoing program to monitor the performance of their pipeline systems. However, the NTSB investigation revealed some gas pipeline operators' performance monitoring programs did not effectively collect and analyze data to determine the extent of possible hazards associated with plastic pipeline systems. The NTSB pointed out, ''such a program must be adequate to detect trends as well as to identify localized problem areas, and it must be able to relate poor performance to specific factors such as plastic piping brands, dates of manufacture (or installation dates), and failure conditions.''

Copies of this report may be obtained by searching the NTSB Web site at *www.ntsb.gov.*

II. Advisory Bulletins Previously Issued by PHMSA

The NTSB made several recommendations to PHMSA and to trade organizations in its 1998 special investigation report. In response, PHMSA issued three advisory bulletins. The first advisory bulletin, ADB–99–01, *Potential Failure Due to Brittle-Like Cracking of Certain Polyethylene Plastic Pipe Manufactured by Century Utility Products Inc,* was published in the **Federal Register** (FR) on March 11, 1999 (64 FR 12211) to advise natural gas pipeline distribution system operators that brittle-like cracking may occur on certain polyethylene pipe manufactured by Century Utility Products, Inc.

The second advisory bulletin, ADB–99–02, *Potential Failures Due to Brittle-Like Cracking of Older Plastic Pipe in Natural Gas Distribution Systems,* was also published in the **Federal Register** on March 11, 1999 (64 FR 12212) to advise natural gas pipeline distribution system operators of the potential for brittle-like cracking of plastic pipes installed between the 1960s and early 1980s.

The third advisory bulletin, ADB–02–07, *Notification of the Susceptibility To Premature Brittle-Like Cracking of Older Plastic Pipe,* was published in the **Federal Register** on November 26, 2002 (67 FR 70806) to reiterate to natural gas pipeline distribution system operators the susceptibility of older plastic pipe to premature brittle-like cracking. The older polyethylene pipe materials specifically identified in ADB–02–07 included, but were not limited to:

- Century Utility Products, Inc. products;
- Low-ductile inner wall ''Aldyl A'' piping manufactured by DuPont Company before 1973; and
- Polyethylene gas pipe designated PE 3306.

This third advisory bulletin also listed several environmental, installation and service conditions in which plastic piping is used that could lead to premature brittle-like cracking failure. PHMSA also described six recommended practices for polyethylene gas pipeline system operators to aid them with identifying and managing brittle-like cracking problems.

III. Plastic Pipe Studies

Beginning January 25, 2001, the American Gas Association (AGA) began to collect data on in-service plastic piping material failures with the objective of identifying trends in the performance of these materials. The resulting leak survey data, collected from 2001 to present, on the county's natural gas distribution systems includes both actual failure information and negative reports (reports of no leads) submitted voluntarily by participating pipeline operating companies.

The AGA, PHMSA, and other industry and state organizations continue to collect and analyze the data. Unfortunately, the data cannot be correlated with the quantities of each plastic pipe material that may be in service across the United States. Therefore, the data does not assess the failure rates of individual plastic pipe materials on a linear basis (i.e. per foot, per mile, etc.). However, the failure data reinforces what is historically known about certain older plastic piping and components. The data also indicates the susceptibility of additional specific materials to brittle-like cracking.

IV. Advisory Bulletin ADB–07–01

To: Owners and Operators of Natural Gas Pipeline Distribution Systems.

Subject: Updated Notification of the Susceptibility of Older Plastic Pipes to Premature Brittle-Like Cracking.

Advisory: All owners and operators of natural gas distribution systems who have installed and operate plastic piping are reminded of the phenomenon of brittle-like cracking. Brittle-like cracking refers to crack initiation in the pipe wall not immediately resulting in a full break followed by stable crack growth at stress levels much lower than the stress required for yielding. This results in very tight, slit-like, openings and gas leaks. Although significant cracking may occur at points of stress concentration and near improperly designed or installed fittings, small brittle-like cracks may be difficult to detect until a significant amount of gas leaks out of the pipe, and potentially migrates into an enclosed space such as a basement. Premature brittle-like cracking requires relatively high localized stress intensification that may result from geometrical discontinuities, excessive bending, improper installation of fittings, dents and/or gouges. Because this failure mode exhibits no evidence of gross yielding at the failure location, the term brittle-like cracking is used. This phenomenon is different from brittle fracture, in which the pipe failure causes fragmentation of the pipe.

All owners and operators of natural gas distribution systems are future advised to review the three earlier advisory bulletins on this issue. In addition to being available in the **Federal Register**, these advisory bulletins are available in the docket, and on PHMSA's Web site at *http://phmsa.dot.gov/* under Pipeline Safety Regulations.

In the first advisory bulletin, ADB–99–01, published on March 11, 1999 (64 FR 12211), PHMSA advises natural gas distribution system operators of the potential for poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc. In the second advisory bulletin, ADB–99–02, published on March 11, 1999 (64 FR 12212), PHMSA advises natural gas distribution system operators of the potential for brittle-like cracking of plastic pipes installed between the 1960s and early 1980s.

In the third advisory bulletin, ADB–02–07, published on November 26, 2002 (67 FR 70806), PHMSA reiterates to pipeline operators the susceptibility of some older plastic pipe to premature brittle-like cracking which could substantially reduce the service life of natural gas distribution systems and to explain the mission of the Plastic Pipe Database Committee (PPDC) ''to develop and maintain a voluntary data collection process that supports the analysis of the frequency and causes of in-service plastic piping material failures.'' The advisory bulletin also lists several environmental, installation and service conditions under which plastic piping is used which is used which could lead to premature brittle-like cracking failure. PHMSA also describes six recommended practices for polyethylene gas pipeline system operators to aid them with identifying and managing brittle-like cracking problems.

Lastly, the susceptibility of some polyethylene pipes to brittle-like cracking is dependent on the resin, pipe processing, and service conditions. As noted in ADB–02–07, these older polyethylene pipe materials include, but are not limited to:

- Century Utility Products, Inc. products;
- Low-ductile inner wall ''Aldyl A'' piping manufactured by DuPont Company before 1973; and
- Polyethylene gas pipe designated PE 3306.

The data now supports adding the following pipe materials to this list:

- Delrin insert tap tees; and,
- Plexco service tee Celcon (polyacetal) caps.

Authority: 49 U.S.C. chapter 601 and 49 CFR 1.53.

Issued in Washington, DC, on August 28, 2007.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. 07–4309 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–M

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2007–28993]

Pipeline Safety: Adequacy of Internal Corrosion Regulations for Hazardous Liquid Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), U.S. Department of Transportation (DOT).

ACTION: Notice of availability of materials; request for comments.

SUMMARY: This notice announces the availability of materials, including a briefing paper prepared for PHMSA's Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) and data on risks posed by internal corrosion on hazardous liquid pipelines. PHMSA is preparing a report to Congress on the adequacy of the internal corrosion regulations for hazardous liquid pipelines. Participants at a meeting of the THLPSSC discussed issues involved in examining the adequacy of the regulations and requested additional data. PHMSA requests public comment on these matters.

DATES: Submit comments by October 9, 2007.

ADDRESSES: Comments should reference Docket No. PHMSA–2007–28993 and may be submitted in the following ways:

- *E-Gov Web site: http://www.regulations.gov.* This Web site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* Docket Management System: U.S. Department of Transportation, Docket Operations, M–30, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001.
- *Hand Delivery:* DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Instructions: Identify the docket number, PHMSA–2007–28993, at the beginning of your comments. If you submit your comments by mail, submit two copies. To receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard. Internet users may submit comments at *http://www.regulations.gov.*

Note: Comments are posted without changes or edits to *http://www.regulations.gov*, including any personal information provided. There is a privacy statement published on *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Barbara Betsock at (202) 366–4361, or by e-mail at *barbara.betsock@dot.gov.*

SUPPLEMENTARY INFORMATION: The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 directs PHMSA to review the internal corrosion regulations in subpart H of 49 CFR part 195 to determine if they are adequate to ensure adequate protection of the public and environment and to report to Congress on the results of the review. As an initial step in the review, PHMSA consulted the THLPSSC at its meeting on July 24, 2007. The briefing paper prepared for the committee members contains preliminary data on risk history as well as questions relating to the internal corrosion regulations. This briefing paper is posted on PHMSA's pipeline Web site (*http://ops.dot.gov*) and has been placed in the docket.

At the meeting, PHMSA officials committed to gathering additional data responding to questions posed by the committee members. PHMSA has updated the data and included data responsive to the committee members. This data is also posted on the pipeline Web site and contained in the docket.

PHMSA requests comments on the adequacy of the internal corrosion regulations and answers to the questions posed in the briefing paper. PHMSA will use these comments in its review of the internal corrosion regulations.

Authority: 49 U.S.C. 60102, 60115, 60117: Sec. 22, Pub. L. 109–468, 120 Stat. 3499.

Issued in Washington, DC on August 27, 2007.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. E7–17538 Filed 9–5–07; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0675]

Proposed Information Collection Activity: Proposed Collection; Comment Request

AGENCY: Center for Veterans Enterprise, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: The Center for Veterans Enterprise (CVE), Department of Veterans Affairs (VA), is announcing an opportunity for public comment on the proposed collection of certain information by the agency. Under the Paperwork Reduction Act (PRA) of 1995, Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension of a currently approved collection, and allow 60 days for public comment in response to the notice. This notice solicits comments for information needed to identify veteran-owned businesses.

DATES: Written comments and recommendations on the proposed collection of information should be received on or before November 5, 2007.

ADDRESSES: Submit written comments on the collection of information through *http://www.Regulations.gov;* or Gail Wegner (00VE), Department of Veterans Affairs, 810 Vermont Avenue, NW., Washington, DC 20420 or e-mail: *gail.wegner@va.gov.* Please refer to ''OMB Control No. 2900–0675'' in any correspondence. During the comment period, comments may be viewed online through the Federal Docket Management System (FDMS) at *http://www.Regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Gail Wegner at (202) 303–3296 or FAX (202) 254–0238.

SUPPLEMENTARY INFORMATION: Under the PRA of 1995 (Pub. L. 104–13; 44 U.S.C. 3501–3521), Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. This request for comment is being made pursuant to section 3506(c)(2)(A) of the PRA.

With respect to the following collection of information, CVE invites comments on: (1) Whether the proposed collection of information is necessary for the proper performance of CVE's functions, including whether the information will have practical utility; (2) the accuracy of CVE's estimate of the burden of the proposed collection of

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 7

U.S. Department of Transportation Call to Action To Improve the Safety of the Nation's Energy Pipeline System

U.S. Department of Transportation Call to Action
To Improve the Safety of the Nation's Energy Pipeline System

Executive Summary

Today, more than 2.5 million miles of pipelines are responsible for delivering oil and gas to communities and businesses across the United States. That's enough pipeline to circle the earth approximately 100 times.

Currently, these liquid and gas pipelines are operated by approximately 3,000 companies and fall under the safety regulations of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA has engineers and inspectors around the country who oversee the safety of these lines and ensure that companies comply with critical safety rules that protect people and the environment from potential dangers. While PHMSA directly regulates most of the hazardous liquid pipelines in the nation, states take over when it comes to intrastate natural gas pipelines. Every state, except Hawaii and Alaska,is responsible for the inspection and enforcement of state pipeline safety laws for the natural gas pipeline systems within their respective state. Some states – about 20 percent - also regulate the hazardous liquid lines within state borders.

In the wake of several recent serious pipeline incidents, U.S. DOT/PHMSA is taking a hard look at the safety of the nation's pipeline system. Over the last three years, annual fatalities have risen from nine in 2008, to 13 in 2009 to 22 in 2010. Like other aspects of America's transportation infrastructure, the pipeline system is aging and needs a comprehensive evaluation of its fitness for service. Investments that are made now will ensure the safety of the American people and the integrity of the pipeline infrastructure for future generations.

For these reasons, Secretary LaHood is issuing a call to action for all pipeline stakeholders, including the pipeline industry, the utility regulators, and our state and federal partners. Secretary LaHood brought together PHMSA Administrator Quarterman and the senior DOT leadership to design a strategy to achieve that goal. The action plan below is the result of those deliberations.

Background

Much of the nation's pipeline infrastructure was installed many decades ago, and some century-old infrastructure continues to transport energy supplies to residential and commercial customers, particularly in the urban areas across our nation. Older pipeline facilities that are constructed of obsolete materials (e.g., cast iron, copper, bare steel, and certain kinds of welded pipe) may have degraded over time, and some have been exposed to additional threats, such as excavation damage.

On December 4, 2009, PHMSA issued the Distribution Integrity Management Final Rule, which extends the pipeline integrity management principles that were established for hazardous liquid and natural gas transmission pipelines, to the local natural gas distribution pipeline systems. This regulation, which becomes effective in August of 2011, requires operators of local gas distribution pipelines to evaluate the risks on their pipeline systems to determine their fitness for service and take action to address those risks. For older gas distribution systems, the appropriate mitigation measures could involve major pipe rehabilitation, repair, and replacement programs. At a minimum, these measures are needed to requalify those systems as being fit for service. While these measures may be costly, they are necessary to address the threat to human life, property, and the environment.

In addition to the many pipelines constructed with obsolete materials, there are also early vintage steel pipelines in high consequence areas that may pose risks because of inferior materials, poor construction practices, lack of maintenance or inadequate risk assessments performed by operators. The lack of basic information or incomplete records about these systems is also a contributing factor. The U.S. DOT is seeking to make sure these risks are identified, the pipelines are assessed accurately, and preventative steps are taken where they are needed.

Action Plan

The U.S. DOT and PHMSA have developed this action plan to accelerate rehabilitation, repair, and replacement programs for high-risk pipeline infrastructure and to requalify that infrastructure as fit for service. The Department will engage pipeline safety stakeholders in the process to systematically address parts of the pipeline infrastructure that need attention, and ensure that Americans remain confident in the safety of their families, their homes, and their communities. The strategy involves:

- A Call to Action – Secretary LaHood is issuing a “Call to Action” to engage state partners, technical experts, and pipeline operators in identifying pipeline risks and repairing, rehabilitating, and replacing the highest risk infrastructure. Secretary LaHood is also asking Congress to expand PHMSA’s ability to oversee pipeline safety.
    - Secretary LaHood and PHMSA Administrator Quarterman have already met with the Federal Energy Regulatory Commission (FERC), the National Association of Regulatory and Utility Commissioners (NARUC), state public utility commissions, and industry leaders to ask all parties to step up efforts to identify high-risk pipelines and ensure that they are repaired or replaced.
    - Secretary LaHood is asking Congress to increase the maximum civil penalties for pipeline violations from $100,000 per day to $250,000 per day, and from $1 million for a series of violations to $2.5 million for a series of violations. He is also asking Congress to help close regulatory loopholes, strengthen risk management requirements, add more inspectors, and improve data reporting to help identify potential pipeline safety risks early.

- The U.S. DOT and PHMSA are convening a Pipeline Safety Forum in April to engage in a working session around the actions that the Department, states, and industry can take to drive more aggressive actions to raise the bar on pipeline safety. The U.S. DOT and PHMSA will compile a report based on ideas, opportunities and challenges presented at the Forum and take action on solutions.

- Aggressive Efforts – The U.S. DOT and PHMSA are calling on pipeline operators and owners to review their pipelines and quickly repair and replace sections in poor condition.

  - PHMSA has asked technical associations and pipeline safety groups to provide best practices and technologies for repair, rehabilitation and replacement programs, and has asked industry groups for commitments to accelerate needed repairs.

  - PHMSA will review all data received from pipeline operators to identify areas with critical needs.

  - PHMSA's Distribution Integrity Management rule will become effective in August, requiring all operators of gas distribution pipelines to evaluate the risks on their pipeline systems and take action to address those risks.

- Transparency - U.S. DOT and PHMSA will execute this plan in a transparent manner with opportunity for public engagement, including a dedicated website for this initiative, and regular reporting to the public.

  - PHMSA will launch a public website with ongoing pipeline rehabilitation, replacement and repair initiatives.

  - All materials from the Pipeline Safety Forum will be publicly posted to the web, followed by a Draft Report for Notice and Comment. Once public input has been collected, PHMSA will publish a final Pipeline Safety Report to the Nation.

###

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 8

Recommended Protocol For Avista Assessment of Aldyl 'A' and Other MDPE Pipes

Palermo Plastics Pipe (P^3)
Consulting
Dr. Gene Palermo
www.plasticspipe.com

"Recommended Protocol For Avista Assessment of Aldyl 'A' and Other MDPE Pipes"

By

Dr. Gene Palermo
President
Palermo Plastics Pipe Consulting
www.plasticspipe.com

March 4, 2011

"Recommended Protocol For Avista Assessment of Aldyl 'A' and other MDPE Pipes"

I. Summary

As a result of the Agreement between Avista and the WS UTC that resulted from an Aldyl "A" rock impingement failure, Avista needs to assess the Aldyl "A" pipe in its gas distribution system along with the soil conditions. Avista requested assistance from Dr. Gene Palermo based on his experience with Aldyl "A" pipe.

In this report I have summarized the various Alathon MDPE (medium density polyethylene) resins that were used to produce Aldyl "A" pipe for natural gas distribution applications, and their respective resistance to slow crack growth (SCG) failure. In this report I have also described the Rate Process Method (RPM) and compared RPM projections to the resin SCG resistance and to the field performance for the various generations of Aldyl "A" pipe. Based on this information, I then proposed the following recommended protocol for Avista to use in assessing MDPE pipes in their gas distribution system. For the purposes of this report, when I use the term "pipe", I am referring to main pipe sizes, 1-1/4" IPS and larger. The smaller service tubing sizes are not an issue for rock impingement. Also, none of the Aldyl "A" service sizes (tubing sizes) had a low ductile inner wall (LDIW).

1) All Aldyl "A" pipe manufactured prior to 1984 should be evaluated for replacement.

a) If the pipe is LDIW (low ductile inner wall) Aldyl "A" pipe, Avista should start a prioritized pipe replacement program immediately.
b) If the Aldyl "A" pipe is installed in soil with rocks larger than ¾", Avista should start a prioritized pipe replacement program immediately.
c) If the Aldyl "A" pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys per DOT Part 192 should be followed.

2) All Aldyl "A" pipe manufactured during or after 1984 and all yellow MDPE pipe, both PE 2406 and unimodal PE 2708, should also be evaluated.

a) If this pipe is installed in rocks larger than ¾" in size, Avista should evaluate the pipe and consider replacing it if they begin to experience rock impingement failures, and should conduct leak surveys more frequently than required by DOT Part 192, until replacement.
b) If this pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys should be followed.

3) All bimodal PE 2708 pipe may be installed by Avista in any soil condition. Due to the very high SCG resistance of this pipe it is essentially immune to rock impingement failure.

This pipe is similar to bimodal PE 100 RC pipe that has been installed in Europe for the past five years in natural rocky backfill. This PE 100 RC material was developed in Europe so that gas companies could use “sandless” backfill, i.e. use the natural rocky backfill. The SCG resistance of bimodal PE 2708 is even greater than PE 100 RC.

II. Background – Dr. Palermo

Dr. Gene Palermo received a Bachelor of Science in Chemistry from St. Thomas College in St. Paul, MN in 1969 and a Ph.D. in Analytical Chemistry from Michigan State University in 1973.

Dr. Palermo has been in the plastic piping industry for over 35 years. He worked for the DuPont Company from 1976 to 1995 in the Aldyl “A” polyethylene (PE) pipe business for natural gas distribution. During that time, he was involved with research, manufacturing and marketing the Aldyl “A” piping system for natural gas applications. Dr. Palermo then developed the initial use of polyamide (PA) 11 for high-pressure gas distribution, up to 250 psig for SDR 11, to replace metal pipe while with Elf AtoChem during 1995 and 1996.

Dr. Palermo was the Technical Director for the Plastics Pipe Institute (PPI) from 1996 until 2003. As Technical Director, Dr. Palermo was chairman of the Hydrostatic Stress Board (HSB) on which he had served for over 20 years to develop pressure-rating methods for plastic pipe; and chairman of the Technical Advisory Group for ISO/TC 138 for international plastic piping systems. Dr. Palermo has developed standards for plastic pipe and fittings in several standards bodies; ASTM F17, CSA B137, AASHTO, and ISO/TC 138.

Most of Dr. Palermo’s expertise has been in the natural gas distribution industry. He has been a member of the AGA Plastic Materials Committee for over 25 years, the Gas Pipe Technology Committee for over 15 years, an instructor for the DOT inspector training school, and was an original member of the Plastic Pipe Database Committee. Dr. Palermo has also developed a one day Technical Seminar for the gas distribution industry.

Dr. Palermo currently serves as a member of PPI, AGA, GPTC (Chairman of Manufacturers Division), AWWA, ASTM F 17 (Director of Division I), ASTM D 20, CSA B137, CSA Z662 (Chairman of Clause 12 Gas Distribution), and ISO/TC 138. Dr. Palermo is currently president of his consulting firm – Palermo Plastics Pipe Consulting. Dr. Gene Palermo was recently honored with the **ASTM Award of Merit**, which is the highest Society recognition for individual contributions to standards activities, and the **AGA Platinum Award of Merit**, which is the highest award that can be achieved within AGA. Dr. Palermo is the only person to receive both of these very prestigious awards!

III. DuPont Aldyl "A" Resins

A. Alathon 5040

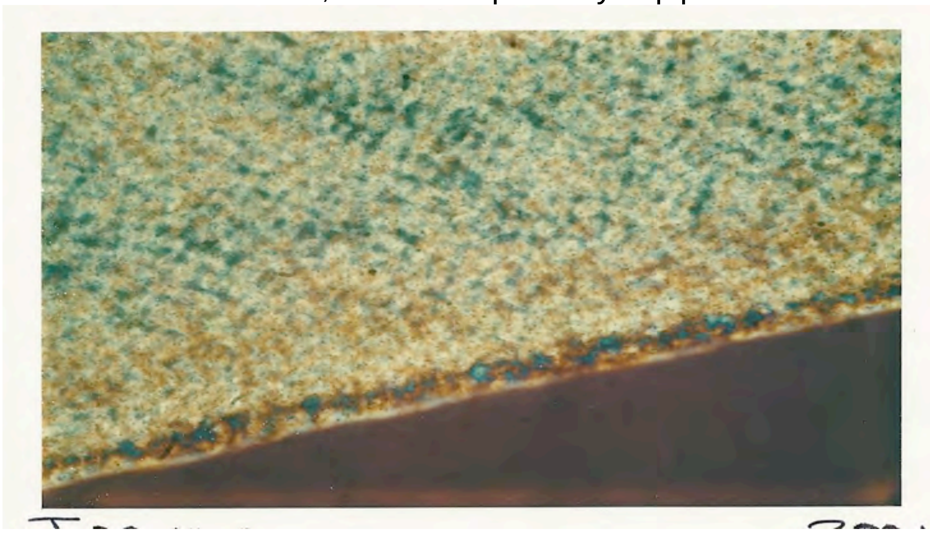
The PE resin that DuPont initially used for the production of Aldyl "A" pipe from 1965 to 1970 was Alathon 5040. This PE resin used a butene comonomer and had a base resin density of 0.935 g/cc and a melt index (MI) of 2.0 g/10 min. These two properties of melt index and density control many of the other physical properties for PE materials. Most of the other PE materials used for the gas industry at that time had an MI of about 0.2 g/10 min, so Aldyl "A" was not fusion compatible with these other PE materials. With this relatively low molecular weight (high MI), the recommended butt fusion temperature for Aldyl "A" pipe was 310ºF (154ºC), compared to 400ºF (204ºC) to 500ºF (260ºC) for the other PE materials. Aldyl "A" pipe installed by Avista between 1968 and 1970 was likely made from Alathon 5040 resin.

B. Alathon 5043

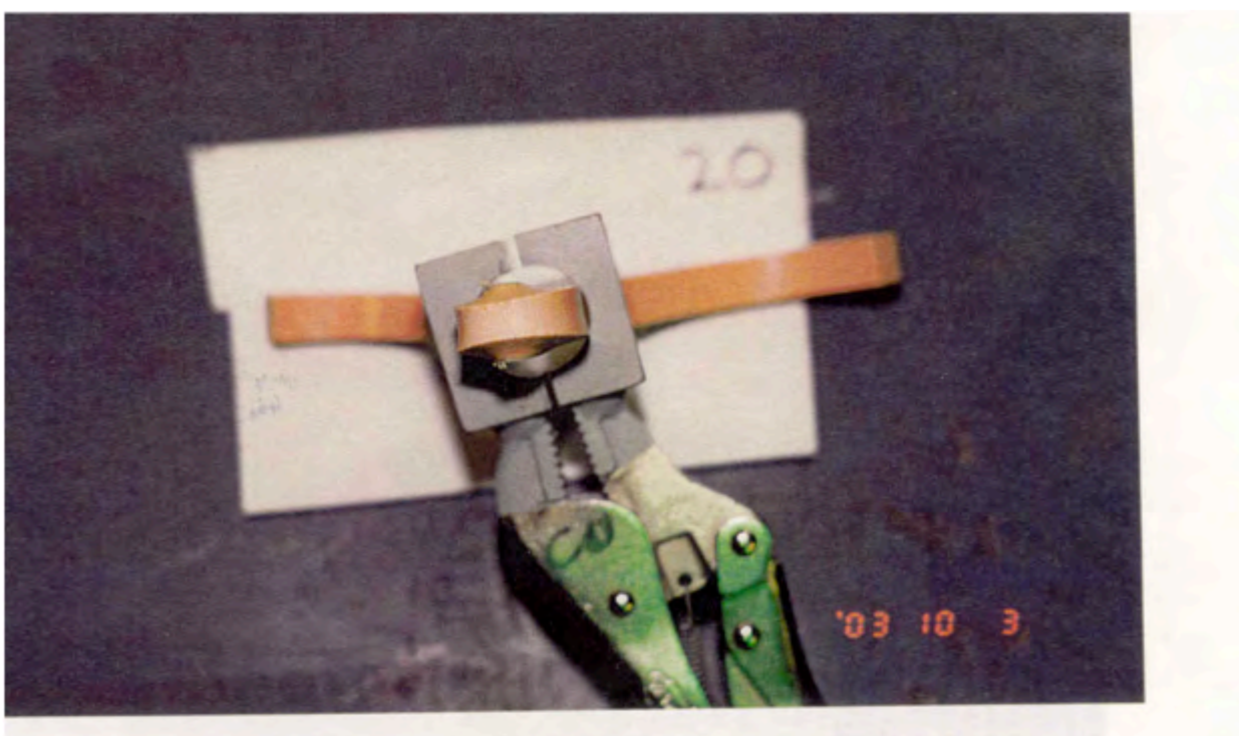
Because some of the small tubing sizes made from the Alathon 5040 resin did not consistently meet the ASTM D 1599 quick burst minimum stress requirement of 2520 psi, DuPont decided to use a higher density PE resin. DuPont changed to Alathon 5043 resin in 1970. This was also a butene comonomer, but with a higher base resin density of 0.939 g/cc to increase the yield strength and more consistently meet the quick burst stress requirements. In order to maintain a balance of molecular parameters, the molecular weight was increased when the density was increased, and the corresponding melt index was 1.2 g/10 min. With this higher molecular weight (lower MI) the butt fusion melt temperature was increased to 340ºF (171ºC).

Alathon 5043 was the primary PE resin that DuPont used for Aldyl "A" pipe from 1970 to 1984. It was also during this time that the LDIW (low ductile inner wall) phenomenon occurred. In the late 1970 through the 1971 era, DuPont had a manufacturing issue that resulted in a brittle inside surface. This was finally detected during some elevated temperature stress rupture testing that resulted in premature failures, in which multiple slits were observed as opposed to the normal single slit failure. It was also noted that the spherulites on the inside surface were very large (30 to 40 microns), as shown in the photo below. Because of these large spherulites on the inside surface, this pipe is called "large bore spherulite" pipe, or the term more commonly used is LDIW for "low ductile inner wall". The terms "low ductile inner wall" and "large bore spherulites" are synonymous. The brittle inside surface resulted from the manufacturing process that degraded the inner surface. The premature failures were due to an oxidized inner surface that dramatically reduced the initiation time and thus the overall failure time. The effect of this LDIW surface on long-term pipe performance has been determined using the Rate Process Method (RPM), which is discussed in Appendix A (this is a paper that I presented at the 2004 AGA Operations Conference). In early 1972 DuPont changed the manufacturing process to prevent these large spherulites from forming.

DuPont estimated that about 30% to 40% of the pipe it produced in 1970 and 1971 had an LDIW inner surface, and it was primarily in pipe sizes 1-1/4" to 4" IPS.



When Avista exhumes Aldyl "A" pipe manufactured during 1970 to 1972 (year codes F, G and H), they should first determine if it has an LDIW surface. This can be accomplished with a reverse bend test on a ½" strip of Aldyl "A" pipe. If the inside surface is smooth and shiny, then it is likely normal production Aldyl "A" pipe. If the inside surface has cracks or crazes, as shown in the photo below, then it is likely an LDIW inner surface.



C. Alathon 5046-C

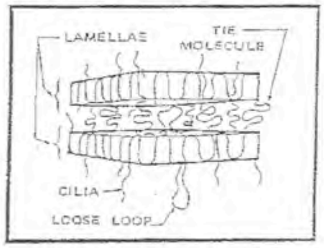
Around 1984 DuPont made a significant change in the PE resin as they switched from a butene comonomer to an octene comonomer. The original octene resin was called Alathon 5046-C, and it had a melt index of 1.1 g/10 min and a base resin density of 0.939 g/cc. This change to octene resulted in a significant improvement in slow crack growth (SCG) resistance and in long-term performance. The octene comonomer has longer side branches than butene (six carbons instead of two carbons), and this improved the efficiency of the tie molecules, which control long-term performance. This is explained in Figure 1. Polyethylene is known as a semi-crystalline polymer, meaning part of the polyethylene is in a crystalline region and part in an amorphous region. In the crystalline region, the molecules form crystals known as "lamellas" – this is also known as "folded chain morphology" for polyethylene, and these crystals are shown in the top photo of Figure 1. When a PE molecule exits the crystal and terminates, it is called a "cilia". When a PE molecule exits and returns to the same crystal it is called a "loose loop". When it exits and then enters another crystal it is called a "tie molecule". These are the long chain molecules that literally "tie" the crystals together. This combination of cilia, loose loops and tie molecules form the "amorphous" portion of PE.

When a high load is applied to PE, the failure that results is a short-term ductile failure; the crystals break apart as shown in the middle photo of Figure 1. These high load or high stress properties are the short-term properties, such as yield strength, and are dependant on the PE base resin density. When a lower load (stress) is applied to PE material the failure mode is a long-term slit or brittle failure. In this case, the amorphous region unravels as the lamellas separate. As they continue to separate, it is the tie molecules that hold these lamellas together, as shown in the bottom photo of Figure 1. When these tie molecules finally break, a crack forms and then advances or grows, which results in the long-term failure mode known as slow crack growth (SCG).

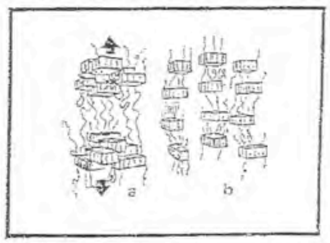
When the load is initially applied to the PE material, a craze zone forms at the tip of a small crack or an imperfection. This craze zone is due to the alignment of the tie molecules as the load is applied. Eventually, the tie molecules begin to break, and this causes the crack to grow to the end of the craze zone. At this point, the crack arrests (stops) and a new craze zone forms, and the process continues. The slow crack growth phenomenon thus consists of crack growth followed by crack arrest, then crack growth followed by crack arrest, etc. This growth/arrest pattern results in growth rings on a fracture surface, much like "tree rings" that form on a tree. These growth rings are very apparent in actual PE field failures due to slow crack growth, and they are also very apparent in elevated temperature stress rupture testing of PE pipe or fittings. The duplication of this crack/arrest failure mode in laboratory testing is the reason that prediction models, such as the Rate Process Method, are very good.

FIGURE 1

- POLYETHYLENE MOLECULES

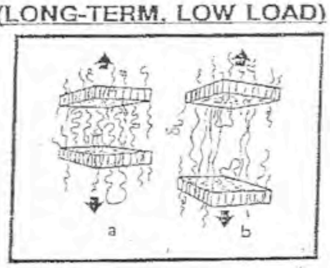


- DUCTILE FAILURE (SHORT-TERM, HIGH LOAD)



SHORT-TERM STRENGTH IS BASED ON DENSITY (CRYSTAL LATTICE INTEGRITY)

- SLIT FAILURE (LONG-TERM, LOW LOAD)

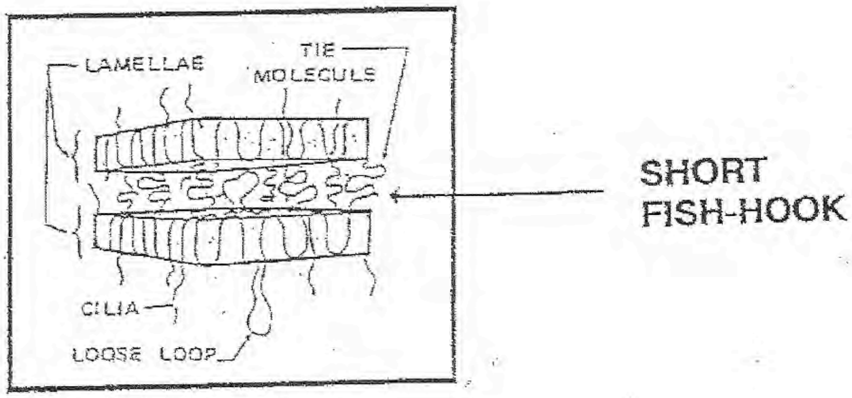


LONG-TERM STRENGTH IS BASED ON EFFICIENCY OF TIE-MOLECULES.

Figure 1 – Tie Molecules in Polyethylene

TIE MOLECULE EFFICIENCY

THE EFFICIENCY OF THE TIE MOLECULES IN KEEPING THE CRYSTAL LATTICES TOGETHER IS BASED ON THE COMONOMER, WHICH ACTS LIKE A "FISH-HOOK".



BY MODIFYING THE COMONOMER AND MAKING THE "FISH-HOOKS" LONGER, THE TIE MOLECULES ARE MORE EFFICIENT.

Figure 2 – Efficiency of Tie Molecules

With the butene comonomer, there are only two carbons as a side branch on the PE molecule, and these act as “short fish hooks” (Figure 2) in trying to prevent the tie molecule from unraveling. With the octene comonomer, there are now six carbons on the side branches, and these act as much longer fish hooks and are more efficient in preventing the tie molecules from unraveling. Since these longer fish hooks are more efficient in keeping the tie molecules from unraveling, it takes a longer time for the tie molecules to break. This increased efficiency of the tie molecules results in a significantly longer time for the crack to grow and thus for a failure to occur, as shown below in a typical 80ºC/120 psig stress rupture test for LDIW Aldyl “A” and Aldyl “A” pipe, using test method ASTM D 1598:

- LDIW - Alathon 5043 resin (butene comonomer) 10 hours
- Alathon 5043 resin (butene comonomer) 100 hours
- Alathon 5046C resin (octane comonomer) 1000 hours

There is an order of magnitude difference in the failure time between LDIW Aldyl "A" and normally produced Aldyl "A" pipe. There is also an order of magnitude difference in the failure time between the butene comonomer Alathon 5043 resin and the octane comonomer Alathon 5046C resin. With this improvement in long-term performance, DuPont called this new product Improved Aldyl "A". DuPont began production of Aldyl "A" pipe using Alathon 5046-C in 1984. Any pipe manufactured during 1984 or later is likely improved Aldyl "A" pipe with a much higher resistance to SCG and with much greater resistance to rock impingement failure than standard Aldyl "A".

D. Alathon 5046-U

DuPont recognized the importance of the tie molecules, and the octene comonomer with the longer fish hooks that improved the efficiency of these tie molecules. In 1988 DuPont announced another improvement with the introduction of Alathon 5046-U. They added more octene comonomer to the resin, which decreased the density to 0.933 g/cc. The melt index remained at 1.1 g/10 min. This additional comonomer increased the number of "long fish hooks" and thus increased the efficiency of the tie molecules even more. This resulted in another order of magnitude improvement in slow crack growth resistance, as evidenced by 80ºC/120 psig stress rupture testing for Aldyl "A" pipe:

- LDIW - Alathon 5043 resin 10 hours
- Alathon 5043 resin 100 hours
- Alathon 5046-C resin 1000 hours
- Alathon 5046-U resin 10,000 hours

This product was also called improved Aldyl "A". An advantage of the lower density was increased flexibility for the pipe. This made the pipe easier to bend, easier to coil and uncoil – especially in cold weather, and easier to squeeze-off – especially in cold weather. These installation advantages, coupled with the improved SCG resistance, made Alathon 5056-U one of the best PE materials available for the natural gas distribution market.

E. Alathon 5046-O

The last change in the resin for Aldyl "A" pipe came in 1992 with the introduction of Alathon 5046-O. DuPont developed technology whereby the octene comonomer could be selectively placed on the high molecular weight molecules. Since the tie molecules are very high molecular weight, much of the octene comonomer was thus added to the molecules that directly affect long-term performance. Since the amount of comonomer remained the same, the density was still 0.933 g/cc and the melt index was still 1.1 g/10 min. This final change in the PE resin resulted in another improvement in slow crack growth resistance, as evidenced by 80ºC/120 psig stress rupture testing for Aldyl "A" pipe:

- LDIW - Alathon 5043 resin 10 hours
- Alathon 5043 resin 100 hours
- Alathon 5046-C resin 1000 hours
- Alathon 5046-U resin 10,000 hours
- Alathon 5046-O resin >30,000 hours

F. Summary of Resins

A summary of the various DuPont Alathon resins used to produce Aldyl "A" pipe is provided in Table 1 below:

Table 1 - DuPont Aldyl® "A" PE Pipe and Alathon® PE Resins

#	Name	Year	Density	Melt Index	Co-monomer	Color	Resin	Comment
1	Aldyl "A"	1966 – 1970	0.935	2.0	Butene	Tan	Alathon® 5040	Original Alathon resin
2	Aldyl "A"	1970 – 1984	0.939	1.2	Butene	Tan	Alathon 5043	Increased density due to quick burst test
	LDIW Aldyl "A"	1971 – 1972	0.939	1.2	Butene	Tan	Alathon 5043	Manufacturing issue
3	Improved Aldyl "A"	1984 – 1988	0.939	1.1	Octene	Tan	Alathon 5046-C	Changed comonomer
4	Improved Aldyl "A"	1988 – 1992	0.933	1.1	Octene	Tan	Alathon 5046-U	Added more comonomer
5	Improved Aldyl "A"	1992 -	0.933	1.1	Octene	Tan	Alathon 5046-O	Placed comonomer on high molecular weight molecules

IV. <u>Rate Process Method Projections</u>

Appendix A is a paper that I presented at the 2004 AGA Operations Conference, "Correlating Aldyl "A" and Century PE Pipe Rate Process Method Projections With Actual Field Performance". In this paper, I discuss the Rate Process Method (RPM) as a means of determining projected long-term performance based on laboratory elevated temperature stress rupture testing. An important feature of RPM is that it can be used not only for projections based on the primary load, internal pressure, but also for secondary loads, such as rock impingement. It is very important that the failure mode that is observed in the field rock impingement failures has been duplicated in the laboratory with an indentation jig. This is why RPM projections correlate so well with actual field experience.

Based on this field experience and the RPM projections in Appendix A, I believe that Avista has to be particularly concerned about any LDIW (low ductile inner wall) pipe in its system. I recommend that all LDIW pipe be replaced immediately regardless of the soil condition. If the Aldyl "A" pipe was manufactured prior to 1984, then the soil conditions need to be assessed.

Any Aldyl "A" pipe manufactured during or after 1984 has significantly more resistance to SCG and resistance to rock impingement failure. The same it true for the yellow PE 2406 materials or current unimodal PE 2708 materials. I would place all these materials in the same category as far as Avista assessment.

The new bimodal PE 2708 is in a new category by itself. This material has the highest SCG resistance of any gas pipe material in the world – with a published PENT (Pennsylvania Notch Test) value over 15,000 hours (actually over 30,000 hours on test), using the standard industry test conditions of 80ºC/2.4 MPa. This is significantly higher than the current 100-hour PENT requirement in ASTM D 2513 for all PE materials, and higher than the 500-hour PENT requirement for the new "high performance" PE materials. This bimodal PE 2708, as an MDPE material, has even higher SCG resistance than the new PE 100 RC materials, which have PENT values over 10,000 hours. The PE 100 RC materials have over five years experience in Europe with "sandless" backfill. The gas companies simply use the natural backfill – including rocks. With their very high SCG resistance, both bimodal PE 2708 and PE 100 RC materials are essentially immune to SCG failure from rock impingement.

Papers on PE 100 RC were presented at Plastics Pipe XV in Vancouver, BC during September 2010, and are available on request.

V. Recommended Protocol for Avista Assessment

Based on SCG resistance, RPM projections and their correlation with field experience, and my own experience with PE gas piping materials, here is my recommended protocol for Avista to assess their MDPE materials in their gas distribution system:

1) All Aldyl "A" pipe manufactured prior to 1984 should be evaluated for replacement.

> a) If the pipe is LDIW (low ductile inner wall) Aldyl "A" pipe, Avista should start a prioritized pipe replacement program immediately.
> b) If the Aldyl "A" pipe is installed in soil with rocks larger than ¾", Avista should start a prioritized pipe replacement program immediately.
> c) If the Aldyl "A" pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys per DOT Part 192 should be followed.

2) All Aldyl "A" pipe manufactured during or after 1984 and all yellow MDPE pipe, both PE 2406 and unimodal PE 2708, should also be evaluated.

> a) If this pipe is installed in rocks larger than ¾" in size, Avista should evaluate the pipe and consider replacing it if they begin to experience rock impingement failures, and should conduct leak surveys more frequently than required by DOT Part 192, until replacement.
> b) If this pipe is installed in sandy soil or in soil with rocks up to ¾" in size, the pipe should remain in service and normal leak surveys should be followed.

3) All bimodal PE 2708 pipe may be installed by Avista in any soil condition. Due to the very high SCG resistance of this pipe it is essentially immune to rock impingement failure. This pipe is similar to bimodal PE 100 RC pipe that has been installed in Europe for the past five years in natural rocky backfill. This PE 100 RC material was developed in Europe so that gas companies could use "sandless" backfill, i.e. use the natural rocky backfill. The SCG resistance of bimodal PE 2708 is even greater than PE 100 RC.

Appendix A

Correlating Aldyl "A" and Century PE Pipe Rate Process Method Projections With Actual Field Performance

By Dr. Gene Palermo

A. Introduction

Dr. Chester Bragaw originally described the concept and mathematical basis for using the Rate Process Method for polyethylene (PE) pipe and fitting service projections (1) (2). The Plastics Pipe Institute (PPI) Hydrostatic Stress Board (HSB) conducted an extensive evaluation of this and other methods for forecasting the effective long-term performance of PE thermoplastic piping materials. Basically, all these methods require elevated temperature sustained pressure testing of pipe where the type of failure is of the slit or brittle-like mode. Dr. Gene Palermo and Ivan DeBlieu reviewed details of these evaluations and conclusions in their paper "*Rate Process Concepts Applied to Hydrostatically Rating Polyethylene*" (3).

As a result of these studies, HSB determined that the three-coefficient Rate Process Method (RPM) equation provided the best correlation between calculated long-term performance projections and known field performance of several PE piping materials. It also had the best probability for extrapolation of data based on the statistical "lack of fit" test. Dr. Gene Palermo provided further validation of the Rate Process Method by comparing RPM projections for PE pipe and fittings obtained at elevated temperatures with actual room temperature laboratory failures for the same pipe and fittings (4).

Many resin and pipe producers, as well as users, are using RPM to one degree or another to make relative judgments on specific materials and/or piping products. One example described in this paper has been using RPM to determine projected life of PE pipe exhumed from buried service. The gas engineer may use this projection to determine how much estimated life the PE pipe has, and whether he should leave pipe in the ground or dig it up. These projections are based on the primary load (which is the internal pressure) and service temperature. RPM can also be used to determine the effects of secondary loads such as indentation (rock impingement), squeeze-off, bending or deflection.

Another use of the Rate Process Method is projected performance of polyethylene fittings as discussed in "*Prediction of Service Life of Polyethylene Gas Piping Systems*" by Dr. Bragaw (5) and "*Designing PE Piping Systems: Old Questions and New Answers*" by Dean Hale (6). When testing and evaluating fittings, it is very important that all the failure modes be the same. Because fittings have different geometries, different failure modes may be observed at different test conditions. When applying the RPM calculation, all failure modes must be the same. The three RPM coefficients from each fitting will be different; again, this is due to their different geometries. The referenced paper by Dr. Bragaw shows different Arrhenius plot slopes (log t vs. 1/T) for the different fittings tested, indicating different coefficients due to the different activation energies for the fitting geometries. This RPM test protocol is not intended for mechanical fittings. An example of the Rate Process Method being used to solve a fitting problem is given in Section XII.

DuPont conducted several RPM experiments on butt-fused joints and also on butt fusion fittings. Generally, the butt fusion joint has a shorter failure time at the laboratory conditions selected for testing. Due to the shallower slope for the butt fusion failure mode compared to control pipe, many times the RPM projected performance for the butt fusion joint is actually longer than the RPM projected performance for the control pipe. This is probably why there are not many field failures for properly made butt fusion joints. DuPont also conducted several RPM experiments on socket fusion and saddle fusion joints.

After establishing the coefficients, an appropriate single-point elevated temperature stress rupture test may be established for quality control purposes, as discussed in "*Rate Process Method as a Practical Approach to a Quality Control Method for Polyethylene Pipe*" by Dr. Palermo (7).

B. RPM Test Procedure

Rate Process Method testing of pipe or fitting assemblies is conducted in accordance with ASTM D 1598, "*Standard Test Method for Time-to-Failure of Plastic Pipe Under Constant Internal Pressure*". Fittings are joined to pipe using standard heat fusion joining procedures, such as butt fusion, socket fusion, saddle fusion or electrofusion.

To do a typical RPM experiment requires a minimum of about 18 to 20 specimens at various temperature/pressure conditions. More specimens would provide greater certainty in making projections. Examples are shown in PPI Technical Note 16 (8).

Using slit failure mode data points, one calculates the A, B and C coefficients for the following three-coefficient Rate Process Method extrapolation equation:

$$\boldsymbol{Log\ \mathrm{t} = \mathrm{A} + \frac{\mathrm{B}}{\mathrm{T}} + \frac{\mathrm{C\ Log\ S}}{\mathrm{T}}}$$

Where:

t = slit mode failure time, hours
T = absolute temperature, °K
S = hoop stress, psi

Once the A, B and C coefficients are calculated, the RPM equation can be used for various performance projections (average failure time) at typical use temperature (average annual ground temperature) and use pressure conditions.

Mathematically, these RPM projections are sound. However, they are not absolute and are subject to various experimental errors, unknown deviations and judgment factors. Calculations from the RPM equation should be used in conjunction with all other mechanical, performance, and use factors in making judgments as to design, useful life or application suitability.

C. LDIW Aldyl “A” RPM Projections

Between 1970 and 1971, the DuPont Company produced some Aldyl “A” pipe that had a low ductile inner wall (LDIW) surface. Years later, in the early 1980’s, some of their customers started experiencing failures in LDIW Aldyl “A” PE 2306 pipe that had been subjected to rock impingement. They were also experiencing some failures of LDIW Aldyl “A” pipe that had been squeezed-off. In an effort to explain the effect of this phenomenon on projected life performance, the DuPont Company agreed to conduct a major Rate Process Method research project on LDIW Aldyl “A” pipe exhumed from the area where the failures were occurring.

<u>1. Internal Pressure</u>
DuPont conducted RPM testing on the 2” IPS control (internal pressure only) LDIW Aldyl “A” pipe as received. The raw data for LDIW Aldyl “A” control pipe was summarized in Section IV. The selected temperatures were 80°C (176°F) and 60°C (140°F) with the internal pressures selected to assure that the failure mode was slow crack growth. To do the RPM calculation it is imperative that all the data have the same failure mode. In this case all the failures were an axial crack that initiated at the inside surface and propagated through the wall until failure occurred. The failures times were accelerated due to the degradation at the LDIW surface.

Based on underground thermocouple testing, the gas utility determined that the average annual service temperature was 21°C (70°F). The use pressure for the gas distribution system was 60 psig. The RPM projected performance for this lot of LDIW Aldyl “A” pipe at the use conditions of 60 psig and 70°F was an average failure time of about 150 years with a 5% lower confidence level (LCL) of 60 years. The RPM program calculates the LCL based on the scatter in the data. These data indicate there is a 95% probability that this lot of LDIW Aldyl “A” pipe would last 60 years at the conditions of 60 psig and an average annual ground temperature of 70°F, and a 50% probability it would last 150 years at the same conditions.

<u>2. Rock Impingement</u>
To simulate the rock impingement failures experienced by the gas utility, DuPont developed an indentation jig (Figure 1). It consists of a collar with a bolted thread of 28 UNS pitch. Seven turns of the bolt after it is flush with the pipe introduce an indentation of ¼”. The bolted collar remains on the pipe the entire time it is subjected to stress

rupture testing to simulate the indentation from rock impingement in the field. Testing was again conducted at 80°C and 60°C with the internal pressure selected to assure failure at the indentation.

Due to the difference in slopes for the indentation failure mode vs. the control failure mode, if the pressure were too high, failure would occur in the pipe away from the indentation. At the lower pressures, all failures were inside to outside cracks that initiated at the indentation, just as was the case with the field failures. Also, when the indentation jig was removed, there was residual indentation, which looked identical to the failure mode observed by the gas utility in the field failures. Another characteristic feature of the indentation failures is that they were off axis by a few degrees (a failure due to just internal pressure is exactly in the axial direction). Rock indentation failures exhumed by the gas utility also had off-axis slit failures. These are the three characteristic features of a rock impingement field failure, and all three of these characteristic features were observed in the laboratory indentation failures. This indicates that DuPont successfully duplicated the rock impingement field failures with this laboratory indentation jig. At the gas utility use conditions of 70°F (21°C) and 60 psig the RPM projected performance for the indented LDIW Aldyl “A” pipe was an average failure time of 12 years with an LCL of 8 years.

This reduction of pipe life due to an LDIW surface was a significant discovery for the DuPont Company and as a result, they notified all Aldyl “A” customers to monitor this pipe with an increased leak survey frequency. This was a letter, known as the “Zerbe letter”, issued by Don Zerbe of DuPont to its customers on December 17, 1982, and is included in Attachment 1.

<u>3. Squeeze-Off</u>
To determine the RPM projected performance of squeezed LDIW Aldyl “A” pipe a similar experiment was conducted. All pipe samples were squeezed-off using DuPont recommended procedures and a single bar squeeze tool. The bar was brought to the gap stop and left there for one hour. The tool was removed and all specimens subjected to stress rupture testing at 80°C and 60°C. Again, due to the difference in slopes for the squeeze failure mode vs. the control failure mode, if the pressure were too high, failure would occur in the pipe away from the squeezed area. At the lower pressures, all failures were inside to outside cracks that initiated at the squeeze-off location. At the gas utility use conditions of 70°F and 60 psig the RPM projected performance for the squeezed LDIW Aldyl “A” pipe was an average failure time of 20 years with an LCL of 10 years.

A projected performance of Aldyl “A” pipe that was properly squeezed of less than 50 years was another significant discovery for the DuPont Company. As a result they notified their Aldyl “A” customers again and recommended reinforcement of squeezed LDIW Aldyl “A” pipe. This was a letter, known as the “Roddy letter”, issued by Ed Roddy of DuPont to its customers on August 25, 1986, and is included in Attachment 2.

4. Deflection
Excessive earth loading can cause polyethylene pipe to deflect, which is another form of secondary loading. To simulate field deflection from earth loading, DuPont developed a "deflection jig" as shown in Figure 2. With this jig, varying levels of deflection may be achieved, where deflection is defined as the change in OD (ΔY) divided by the OD. For 5% deflection, $\Delta Y/D$ is 0.05. For an RPM experiment, all deflection levels must be the same and all failure modes must be the same. The typical deflection failure mode is an axial slit on the larger radius surface of the oval shaped pipe. DuPont conducted the RPM deflection experiment with 5% deflection on all specimens. At the use conditions of 70°F and 60 psig the RPM projected performance for the 5% deflected LDIW Aldyl "A" pipe was an average failure time of 18 years with an LCL of 9 years.

5. Bending
The gas utility also experienced a few failures of Aldyl "A" pipe from excessive bending. In this case the field failure mode is a circumferential crack that initiates at the outside surface. To simulate this secondary load of bending, DuPont developed a bending jig (Figure 3). The % bending strain calculation is shown in Figure 4. Again all calculations must be made using the same bending strain and the same failure mode. Due to the different slopes for the control pipe failure mode and the bending failure mode, if the pressure is too high, the failure mode is an axial slit in the pipe away from the bend area. At lower internal pressures, the failure mode is a circumferential slit in the bend area, the same failure mode observed in the field failures. DuPont conducted the RPM bending experiment with 6% bend strain on all specimens. At the gas utility use conditions of 70°F and 60 psig the RPM projected performance for the 6% bend strain LDIW Aldyl "A" pipe was an average failure time of 5 years with an LCL of 3 years.

Figure 5 is a composite plot for LDIW Aldyl "A" pipe summarizing RPM projected slit slopes at the gas utility average temperature of 70°F for control pipe (internal pressure only) and various secondary loads. This composite plot demonstrates the change in slopes for the different failure modes.

D. Gas Utility A Field Experience with LDIW Aldyl "A" Pipe

1. Rock Impingement
Gas utility A first started to experience rock impingement failures in LDIW Aldyl "A" pipe after five years of in-ground service. The number of rock impingement failures increased every year and peaked after 12 years of installation. The number of failures then began to decrease every year. This field experience exactly correlates with the RPM projected performance of indented LDIW Aldyl "A" pipe at their use conditions (average failure time of 12 years with a 5% LCL of 8 years).

2. Squeeze-Off
The first failure in Aldyl "A" pipe experienced by this gas utility due to a squeeze-off was after 12 years of installation. The number of squeeze-off failures has increased slightly. This field experience is consistent with the RPM projections for squeeze-off failures at the use conditions calculated (average failure time of 20 years with a 5% LCL of 10 years).

<u>3. Deflection</u>
The gas utility did not experience any failures in LDIW Aldyl “A” pipe due to excessive deflection. The RPM projection for 5% deflected LDIW Aldyl “A” pipe at the calculated conditions results in an average failure time of 18 years with an LCL of 9 years. Based on this projection, DuPont had developed installation guidelines to prevent failures due to this excessive deflection.

<u>4. Bending</u>
Some bending failures were experienced after just a few years of installation, which exhibited a circumferential slit. The RPM projection for LDIW Aldyl “A” pipe bent to a 6% bend strain at the gas utility calculated conditions is an average failure time of 5 years with an LCL of 3 years. Based on this projection, the gas utility installed some LDIW pipe at a bend strain of about 6%, which corresponds to a bend radius of about 10 times the pipe OD. This exceed DuPont’s minimum bend radius recommendation of 20 times the OD for Aldyl “A” pipe, but provided valuable feedback for the gas utility to reinforce requirements for installation.

E. Gas Utility B Field Experience with LDIW Aldyl “A” Pipe

Another gas utility also kept very good records of Aldyl “A” PE 2306 pipe and fitting failures. They separated failures into two groups based on year of production. One group was Aldyl “A” pipe produced between 1971 and 1973, which would include LDIW pipe. Recall that not all the pipe produced by DuPont in those years had an LDIW surface. The other group was Aldyl “A” pipe produced between 1974 and 1984. This was all “standard” Aldyl “A” pipe. After 1984, DuPont produced “”improved’” Aldyl “A” pipe. The table below summarizes all their Aldyl “A” failures for the two groups based on failure mode. The units are number of failures per one million feet of pipe per year:

Failure Mode	Aldyl “A” (1971 – 1973)	Aldyl “A” (1974 – 1984)
Rock impingement	1.26	0.17
Saddle fusion	1.25	0.51
Fitting crack	0.75	0.30
Fitting bend	0.68	0.32
Squeeze-off	0.61	0.32
Socket fusion	0.57	0.49
Pipe crack	0.27	0.11
Pipe bend	0.11	0.06
Other	2.04	0.75
Total	7.54 failures/ MM ft pipe	3.03 failures/ MM ft pipe
	0.040 leaks/mile	0.016 leaks/mile

Several very interesting observations can be made about the failure summary in this table. 1) First of all, the leak rate for every failure mode decreased for the 1974-1984 Aldyl “A” compared to 1971-1973 Aldyl “A”. This of course is due to the fact that a portion of the 1971-1973 Aldyl “A” pipe contains an LDIW surface. 2) Next, the overall failure rate for 1971-1973 Aldyl “A” of 0.040 leaks per mile is about an order of magnitude LESS than the leak rate for metal pipe of 0.43 leaks per mile as reported by AGA (9).

3) The failure mode with the highest failure rate is rock impingement, which is consistent with the first gas utility’s field experience. The next highest failure rate is for fittings, which include saddle fittings and socket fittings. This is to be expected since heat fused fittings have notches that act as crack initiators. The next category is squeeze-off and the lowest failure rate is for pipe, which is again to be expected.

F. Aldyl “A” and Improved Aldyl “A” RPM Projections

During the 1980’s the DuPont Company had a major research project to conduct RPM testing on many Aldyl “A” and Improved Aldyl “A” pipe and fitting components. These RPM data can be used to project Aldyl “A” performance at this gas utility’s service conditions of an average annual ground temperature of 73°F (23°C) and an operating pressure of 40 psig. These RPM projections are then compared to actual field experience.

1. Pipe

Figure 6 is a composite plot for control pipe (internal pressure only) comparing LDIW Aldyl “A”, standard Aldyl “A” and improved Aldyl “A” at the average annual temperature of 73°F. The table below compares the RPM projected performance for these three generations of control Aldyl “A” pipe at 73°F and 40 psig with the gas utility’s actual field experience.

Control Aldyl “A” Pipe	RPM Projection at 73°F/40 psig (Years)	Field Experience (Failures/MM ft/year)
LDIW	267	0.27
Standard	3408	0.11
Improved	9693	0.0

The RPM projected performance is consistent with this gas utility’s field experience for pipe. As the RPM projected lifetime at their use conditions increases, the number of field failures experienced decreases.

2. Indented Pipe

Figure 7 is a composite plot for indented pipe (indentation jig with ¼" indentation) comparing LDIW Aldyl "A", standard Aldyl "A" and improved Aldyl "A" at the gas utility's average annual temperature of 73°F. For improved Aldyl "A" all failures occurred away from the indentation jig. All failure modes were axial slits in the pipe. The table below compares the RPM projected performance for these three generations of indented Aldyl "A" pipe at 73°F and 40 psig with this gas utility's field experience.

Indented Aldyl "A" Pipe	RPM Projection at 73°F/40 psig (Years)	Field Experience (Failures/MM ft/year)
LDIW	23	1.26
Standard	88	0.17
Improved	9693	0.0

Again, the RPM projected lifetime at this gas utility's use conditions correlates well with actual field experience for rock impingement failures.

3. Squeezed Pipe

Figure 8 is a composite plot for squeezed pipe (standard squeeze-off procedures) comparing LDIW Aldyl "A", standard Aldyl "A" and improved Aldyl "A" at the gas utility average annual temperature of 73°F. For improved Aldyl "A" all failures occurred away from the squeeze-off location. All failure modes were axial slits in the pipe. The table below compares the RPM projected performance for these three generations of squeezed Aldyl "A" pipe at 73°F and 40 psig with the gas utility field experience.

Squeezed Aldyl "A" Pipe	RPM Projection at 73°F/40 psig (Years)	Field Experience (Failures/MM ft/year)
LDIW	46	0.61
Standard	420	0.32
Improved	9693	0.0

Once again, the RPM projected lifetime at this gas utility's use conditions correlates well with actual field experience for squeeze-off failures.

G. Gas Utility C Field Experience with Century Pipe

Gas utility C installed Century PE 2306 pipe in their gas distribution system in the mid 1970's. Century pipe was a tan colored pipe, marketed primarily in the Midwest, made to look like tan Aldyl "A" pipe. In the late 1980's, the gas utility noted that in one area of their system they were experiencing several rock impingement failures in Century pipe after only a few years of service. In another area, they were not experiencing any failures with Century pipe. Nevertheless, the state Public Service Commission notified the gas company that they had to remove ALL Century pipe from their gas distribution system.

The gas utility planned to remove Century pipe (bad) from the area where they were experiencing failures, but they felt they did not need to remove Century pipe (good) from the area where they were not experiencing any failures. They noted that the Century pipe in the two areas had been installed at different times and also the Century pipe had two different production lots. The gas utility contacted DuPont to see if they could conduct RPM testing on the two lots of Century pipe, and then use the results to justify to their Public Service Commission leaving the "good" Century pipe in the ground. They exhumed several feet of "good" and "bad" Century pipe and sent it to DuPont for RPM testing.

H. Century Pipe RPM Testing

The DuPont Company conducted Rate Process Method testing on the exhumed Century PE 2306 pipe in a similar fashion, as was done for Aldyl "A" pipe. Both the "good" and "bad" lots of Century pipe were tested at conditions that result in slit failures.

<u>1. Control Pipe</u>
Control pipe samples (primary internal pressure only) were tested at selected temperatures and internal pressures to produce axial slit failures. At the gas utility conditions of an average annual ground temperature of 60°F (15°C) and an average internal pressure of 60 psig, the RPM projected mean failure time for both lots of Century pipe was over 10,000 years and the 5% LCL was over 1000 years. These RPM projections would indicate good performance for the control (internal pressure only) Century pipe. The gas utility did not have any failures in control pipe for either pipe lot, which correlates well with the RPM projection.

<u>2. Squeezed Pipe</u>
Squeezed pipe RPM projections are based on testing the same lot of 2" Century pipe that has been squeezed-off using standard squeeze-off procedures. DuPont used a single bar squeeze tool with a gap stop of 0.340", which is the standard for Aldyl "A" pipe. After reaching the gap stop, each pipe specimen was left in the squeeze tool for one hour. Specimens tested at too high an internal pressure resulted in an axial slit failure away from the squeeze location. At lower pressures, all failures occurred at the squeeze location for the "bad" pipe lot with a slit initiating at the inside surface. At the gas utility conditions of an average annual ground temperature of 60°F and an average

internal pressure of 60 psig, the RPM projected mean failure time for the “bad” lot of squeezed Century pipe was 300 years and the 5% LCL was 20 years. The “good” pipe lot failed away from the squeeze location at all test conditions. Although the gas utility did not experience any squeeze-off failures, the Rate Process Method does show a distinct difference in the slit or long-term performance of these two pipe lots.

3. Indented Pipe

Indentation is the laboratory method developed by DuPont of simulating point loading such a rock impingement. Indentation jigs were place on both the “good” and “bad” Century pipe lots and tightened to introduce ¼” of indentation. This indentation jig remains on the pipe for the duration of the test.

Again, at higher internal pressures, failure occurred in the pipe away from the indentation jig. This is due to the different slope for the indentation failure mode. At the gas utility conditions of an average annual ground temperature of 60°F and an average internal pressure of 60 psig, the RPM projected mean failure time for the “bad” lot of indented Century pipe was 30 years and the 5% LCL was 8 years. The “good” pipe lot failed away from the indent location at all test conditions. This RPM projection for indented pipe correlates very well with this gas utility’s field experience. They experience several indent failures after a few years for the “bad” pipe and no indent failures for the “good” pipe.

Based on these RPM projections developed by the DuPont Company, in 1990 gas utility C requested the state Public Service Commission to allow them to leave the “good” Century pipe in service. The PSC granted their request because the RPM projections for Century pipe correlated so well with their field experience of no field failures to date. To date, after 20 more years of service, that “good” Century pipe is still in their distribution system and they still have not experienced **any** slit failures – just as predicted by the Rate Process Method.

I. Conclusion

The Rate Process Method is a very powerful tool that can be used to determine the projected life of old generation polyethylene pipe that is in service for natural gas distribution. RPM can project not only the life of control pipe based on internal pressure, but also the life of the pipe subjected to secondary loads such as rock impingement, squeeze-off, bending and deflection. RPM can also project the life of heat fusion fittings, such as butt fusion, socket fusion, saddle fusion and electrofusion. In addition, based on scatter of the data, RPM can project the mean or average failure time at use conditions and the lower confidence level at use conditions.

RPM can be used for older generation PE materials like Aldyl “A”, Century, PE 2306, PE 3306, PE 3406 and PE 3408 materials. Because the new PE materials have such improved resistance to slow crack growth, RPM is not practical for modern PE 2708, PE 4710 or PE 100 materials because the slit failures simply take too long to generate in laboratory conditions.

J. References for Appendix A

1. C. G. Bragaw, “Crack Stability Under Load and the Bending Resistance of MDPE Piping Systems”, Seventh Plastic Fuel Gas Pipe Symposium, New Orleans, October 1980.
2. C. G. Bragaw, “Service Rating of Polyethylene Systems by the Rate Process Method”, Eighth Plastic Fuel Gas Pipe Symposium, New Orleans, November 1983.
3. E. F. Palermo, “Rate Process Concepts Applied to Hydrostatically Rating Polyethylene Pipe”, Ninth Plastic Fuel Gas Pipe Symposium, New Orleans, November 1985.
4. E. F. Palermo, “Using Laboratory Tests on PE Piping Systems to Solve Gas Distribution Engineering Problems”, Tenth Plastic Fuel Gas Pipe Symposium, New Orleans, October 1987.
5. C. G. Bragaw, “Prediction of Service Life of Polyethylene Gas Piping Systems”, Seventh Plastic Fuel Gas Pipe Symposium, New Orleans, October 1980.
6. D. Hale, “Designing PE Piping Systems: Old Questions and New Answers”, Pipeline and Gas Journal, May 1982.
7. E. F. Palermo, “Rate Process Method as a Practical Approach to a Quality Control Method for Polyethylene Pipe”, Eighth Plastic Fuel Gas Pipe Symposium, New Orleans, November 1983.
8. Plastics Pipe Institute Technical Note 16, “Rate Process Method for Projecting Performance of Polyethylene Piping Components”.
9. P. D. Schrickel, “Plastic Pipe Performance”, AGA Operating Section Proceedings – 1984.

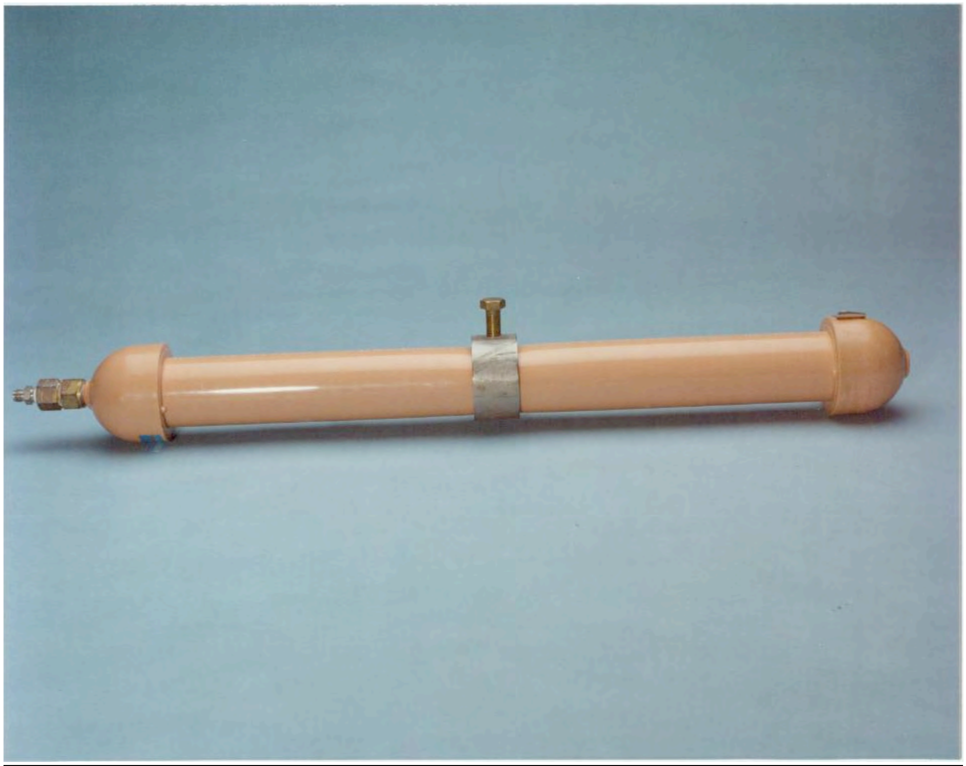


Figure 1 – Indentation Jig

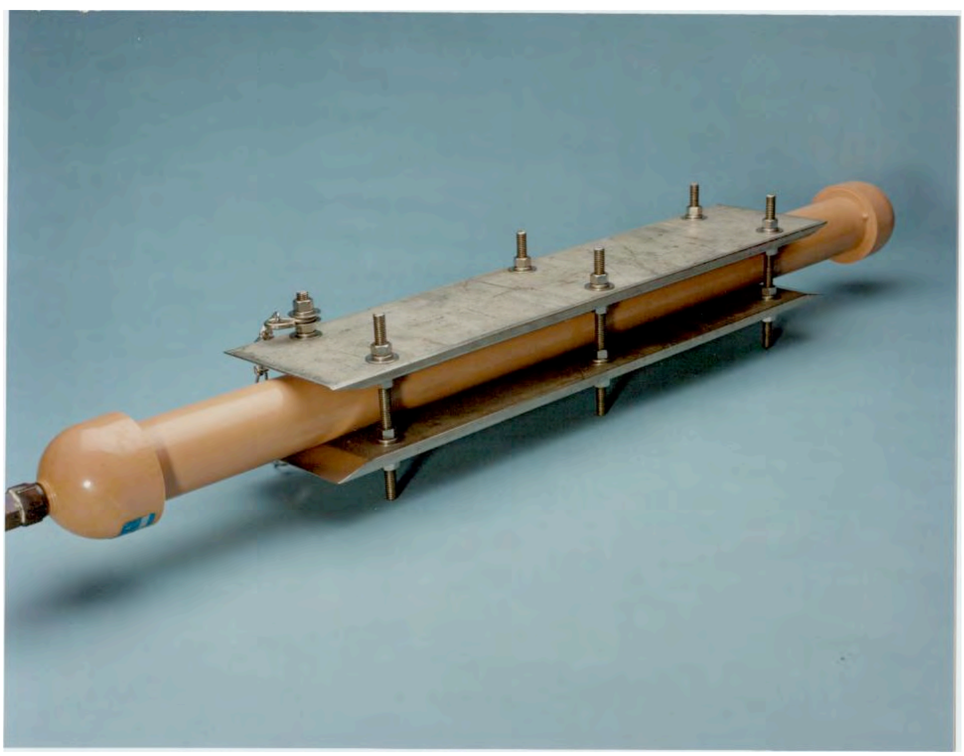


Figure 2 – Deflection Jig

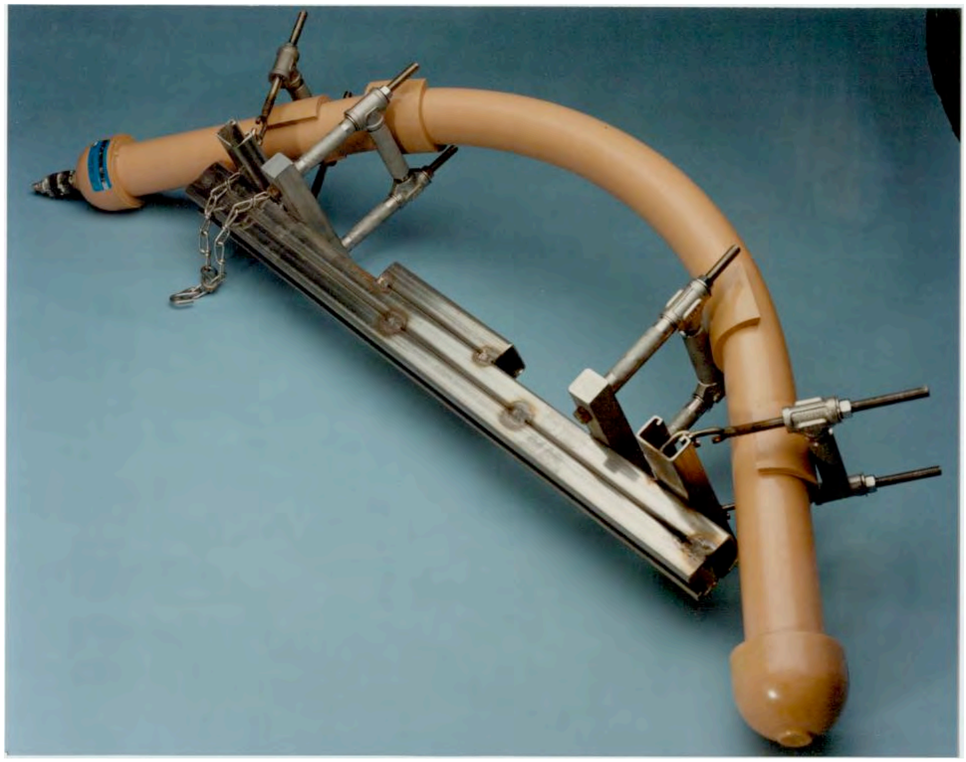


Figure 3 – Bending Jig

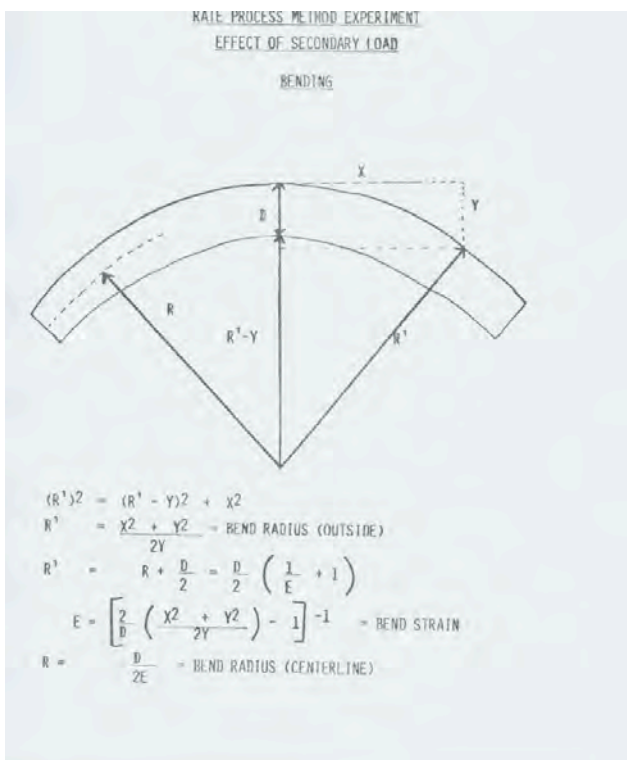


Figure 4 – Percent Bend

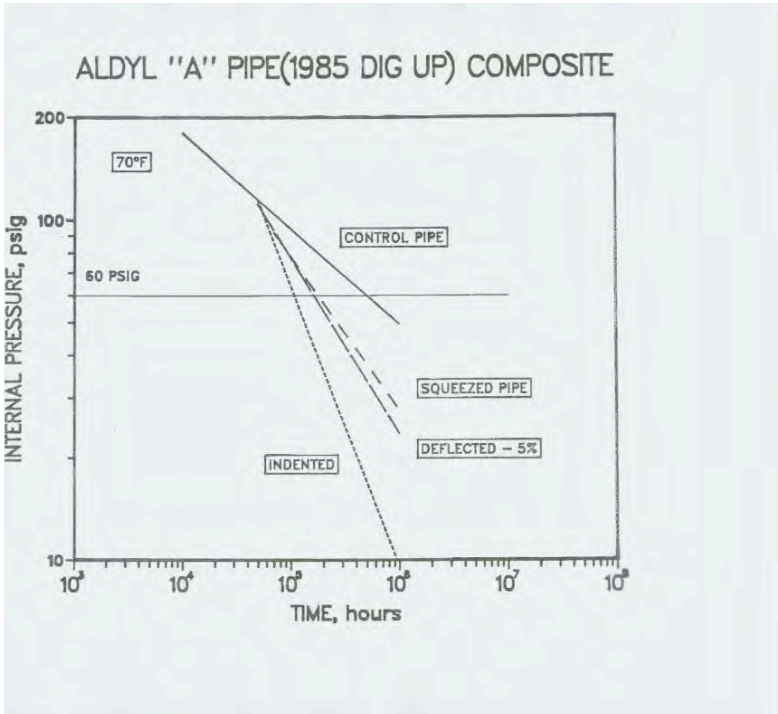


Figure 5 – Composite Showing Control Pipe and Secondary Loading Effects

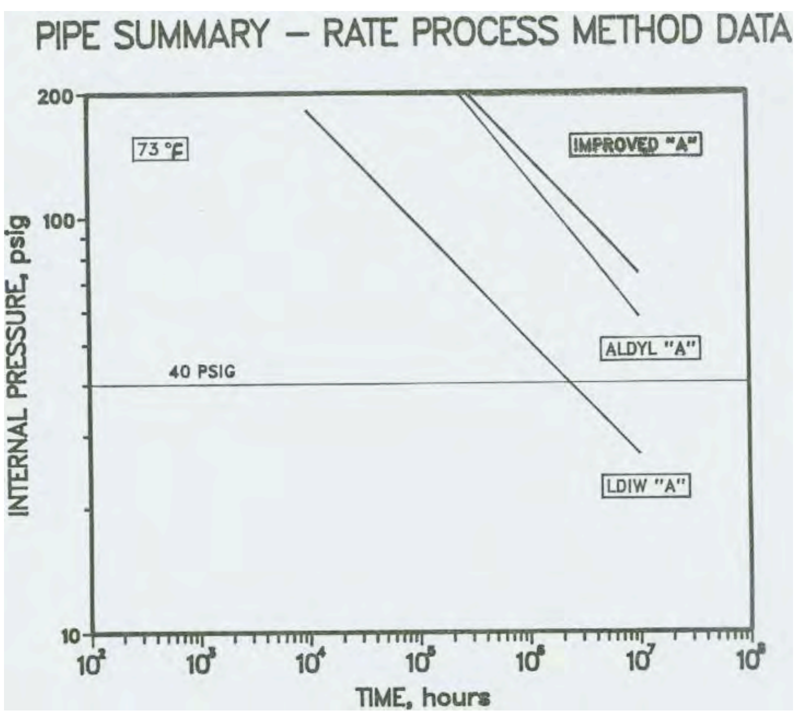


Figure 6 – Composite of Three Generations Control Aldyl "A" Pipe

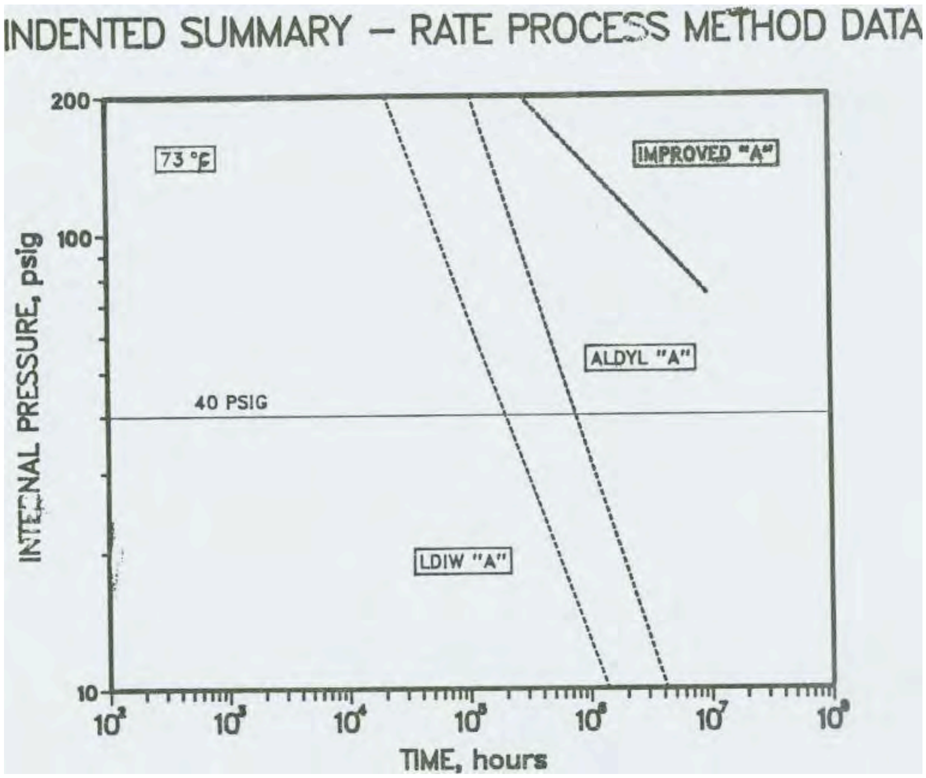


Figure 7 - Composite of Three Generations Indented Aldyl “A” Pipe

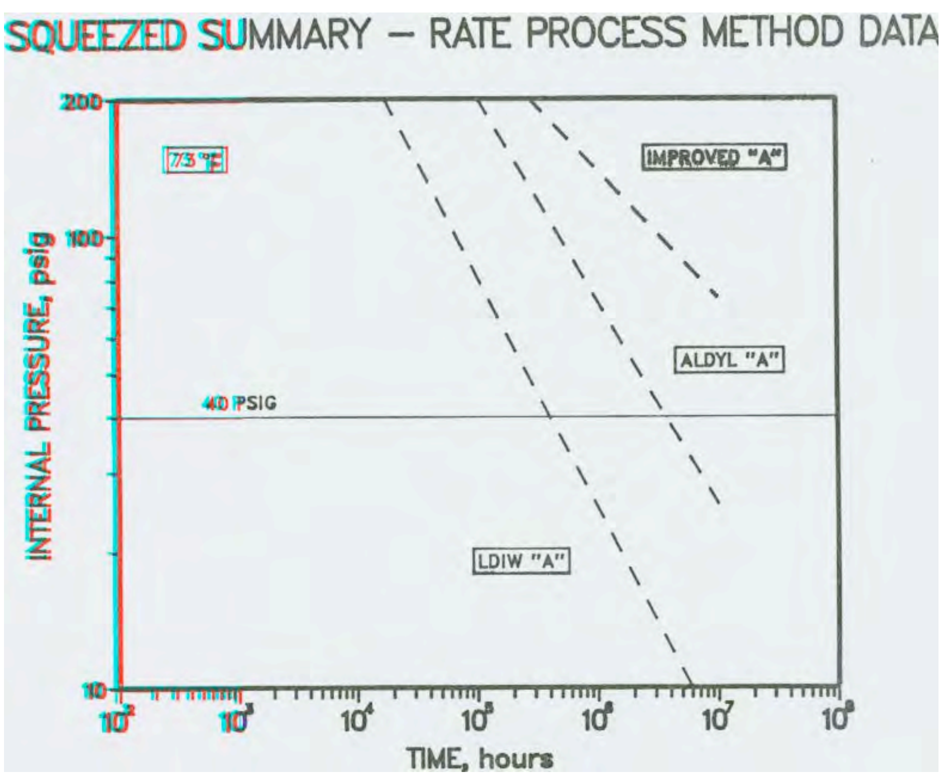


Figure 8 - Composite of Three Generations Squeezed Aldyl “A” Pipe

Attachment 1 – DuPont "Zerbe Letter"

Z-189 REV. 4/81

DU PONT

ESTABLISHED 1802

E. I. DU PONT DE NEMOURS & COMPANY
INCORPORATED
WILMINGTON, DELAWARE 19898

POLYMER PRODUCTS DEPARTMENT

December 17, 1982

It has now been over 18 years since Du Pont developed and introduced the first complete polyethylene piping system designed specifically to meet the needs of the gas distribution industry. Over this period of time, the use of Du Pont's Aldyl® "A" piping system and other polyethylene systems has increased to the point that 84% of the gas distribution pipe installed in 1981 was polyethylene. The outstanding overall performance of the polyethylene pipe installed since 1964 is the primary reason that polyethylene pipe has become the standard for the industry. We believe that the value of polyethylene piping systems has been well documented.

As a responsible long-term supplier committed to the gas industry, we have had a continuing research program aimed at defining the ultimate service life and failure modes of polyethylene pipe in gas distribution service. This program has been and is being supplemented by information received from gas utilities on their experience with Aldyl® "A" pipe.

In metal pipe, corrosion has been the ultimate failure mechanism that has determined when pipe should be replaced. So far, nearly all failures reported in polyethylene piping systems have been caused by either third-party damage or improper fusion practices during installation. These problems can and generally have been minimized by more extensive education and training programs. Although these causes may continue to be the primary reasons for leaks, we believe that every utility with polyethylene piping systems should maintain well-defined leak analysis procedures. Documentation and analysis of individual leak occurrences should help to define the ultimate failure mechanisms, the expected useful life, and appropriate repair or replacement programs.

As in the past, we will continue to assist our customers in planning details of their leak analysis programs including record-keeping, test methods, etc. As an example of the new information such programs can provide, two of our customers have reported instances* of leaks due to slits in Aldyl® "A" pipe made before 1973. The slits have only occurred in 1-1/4" and larger sized pipe. Nearly all of the slits were in pipe installed in point contact with rocks. This low frequency of leaks due to slits has not been reported for pipe made after 1972. Our records indicate that a process improvement was made in late 1971 and early 1972 as part of our continuing effort to utilize our most up-to-date technology. We believe, therefore, that Aldyl® "A" pipe made since that time is more resistant to the formation of slits from point contact with rocks. However, as with coated steel pipe, polyethylene pipe should be installed using established methods which avoid point loading with rocks.

After finding these leaks, the two utilities have increased the frequency of their leak detection surveys for pipe installed before 1973, particularly in those subdivisions where other leaks suggest that rocks may have been included as part of the backfill. We believe that all utilities with Aldyl® "A" pipe installed prior to 1973 should consider more frequent leak detection surveys. The attached sheet shows the purchases by year for your company prior to 1973.

In the future, as we learn of other significant field performance data on our product or develop our own laboratory data, we will share this information with you. High quality polyethylene systems have become an important part of the gas distribution business in providing good performance and safety at minimum costs for installation and repair. It is important as the amount of pipe grows and service times increase, that the management of system maintenance proceeds on a rational, planned basis. We hope the ideas and information included here are helpful toward that end. We look forward to your comments and questions.

Sincerely,

Don F. Zerbe, Jr.
Marketing Manager
Aldyl® Piping Systems

DFZ:dmst
Attachment

* Averaging less than 1% of all field repairs.

Attachment 2 – DuPont "Roddy Letter"

DU PONT ALDYL® PIPING SYSTEMS
QUALITY • INNOVATION • SERVICE

E. I. DU PONT DE NEMOURS & COMPANY (INC.) WILMINGTON, DELAWARE 19898
ALDYL® Piping Systems

August 25, 1986

Dear Customer:

Over twenty years have passed since the first full Aldyl® "A" Polyethylene Piping System was installed in gas distribution service. During those decades both the gas industry and system suppliers have gained experience. As a result, today's systems incorporate improved resins and protective additives, system components are readily available, tooling and installation techniques have been improved, and testing methods have been developed to define design strength and estimate long-term system performance.

Consistent with our position as a reliable and responsible supplier to the gas distribution industry, Du Pont has continued to conduct research programs aimed at new product development and better understanding of existing product performance. We have, over the past years, shared the results of this research effort with you, our customers.

One of the major technical advancements derived from these research programs has been the development by Du Pont of the Rate Process Method (RPM) to estimate long-term system performance. This accelerated test for estimating pressure capability at use conditions is based on the demonstrated Arrhenius principle, relating material strength to temperature. The method is supported by many hundreds of data points at several test temperatures.

RPM estimates enable us to quantify performance of Aldyl® "A" systems. These estimates have shown certain limitations in some 1-1/4 inch and larger Aldyl® pipe installed prior to 1973 which were not previously shown by standard state-of-the-art testing (ASTM D-2837) available at the time. RPM estimates have confirmed that service life of this pipe may be reduced by rock impingement, which is contrary to recommended practice, as communicated previously.

It has now also been shown that the life of pre-1973 1-1/4 inch and larger pipe is shortened at squeeze-off points. For example, RPM estimates show that for squeezed pre-1973 SDR-11 pipe operating at 60 psig and a ground temperature of 70°F (e.g. conditions in parts of the southwestern U.S.) a mean

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life of about 20 years, after squeeze, can be expected. When ground temperature is 60°F, however, the mean life of a squeeze point in such pipe is projected to be about 50 years. The effects of temperature, rock impingement and squeeze-off predicted by RPM are being substantiated by actual field experience.

Based on this new information, reinforcement is recommended to extend the life of pre-1973 pipe when squeeze-off procedures are used. Alternatively, through your own field experience you may have developed other methods you have found to be effective to extend life of squeezed polyethylene pipe.

There are a number of suppliers of reinforcement clamps, and an ASTM guide for selection and use of full encirclement type clamps is near completion. Key items of this proposed guide are summarized in the attachment.

RPM estimates show that for Du Pont's current Aldyl® "A" product:

- Resistance to failure as a result of rock impingement has been improved significantly; and
- Long-term performance is unaffected by squeeze-off (provided proper procedures are followed).

We trust this update on laboratory results and field experience will be helpful in managing Aldyl® systems. Our RPM data on squeeze-off, rock impingement, deflection and other conditions are available, should you wish to use them to help characterize your system, and we welcome discussion of these data with you. We look on such exchanges of information as part of our ongoing partnership in the safe, economical distribution of natural gas.

Sincerely,

E. J. Roddy
Manager
Aldyl® Piping Systems, U.S.
SPECIALTY PRODUCTS & SERVICES DIVISION

EJR1:04/dle
8/25/86
Attachment

SUMMARY OF PROPOSED ASTM DOCUMENT

STANDARD GUIDE FOR THE SELECTION AND USE OF FULL ENCIRCLEMENT TYPE BAND CLAMPS FOR REINFORCEMENT OR REPAIR OF POLYETHYLENE GAS PRESSURE PIPE

- Full encirclement band clamps can be used to reinforce PE pipe where it has been squeezed-off.
- The user should confirm that the band clamp manufacturer recommends his product for reinforcement of PE pipe.
- The user should obtain recommended step-by-step installation instructions from the band clamp manufacturer.
- General considerations to determine appropriateness of using band clamps, design requirements for band clamps, and test methods for evaluation are the responsibility of the band clamp manufacturer.
- The band clamp should be long enough so that it extends 2.5 inches beyond each side of the squeeze-off area.
- The PE pipe should be clean and rounded prior to band clamp installation.

This proposed ASTM document is on the current F-17 Main Committee ballot. Several wording changes may occur as the document proceeds through the ASTM ballot process. Since the proposed balloted document cannot be reproduced or quoted, the key items related to reinforcement of squeezed PE pipe have been summarized here. The final approved document may appear in the 1987 Book of ASTM Standards.

EJR1:04/dle
8/25/86

Appendix B
Dr. Gene Palermo CV

Palermo Plastics Pipe (P^3) Consulting

Dr. Gene Palermo
654 Watershaw Drive
Friendsville, TN 37737

PH: 865-995-1156
FAX: 865-995-0115
website: **www.plasticspipe.com**
e-mail: **gpalermo@plasticspipe.com**

I. Consultant Services Offered

A. Manufacturers

Palermo Plastics Pipe (P^3) Consulting will aid plastic pipe manufacturers (resin companies and pipe companies) to achieve HDB (Hydrostatic Design Basis) and MRS (Minimum Required Strength) pressure ratings through the Hydrostatic Stress Board (HSB), assist with HSB special cases, develop or revise industry standards (ASTM, CSA, AASHTO, ISO), write petitions to the DOT, and/or aid in marketing plastic pipe products to the end user.

B. End users

Palermo Plastics Pipe (P^3) Consulting will aid end users, primarily gas utilities, to evaluate or qualify plastic pipe products (primarily polyethylene and polyamide 11), revise industry standards, and/or conduct failure analysis of plastic pipe products. P^3 Consulting will also present technical seminars at gas company locations to provide background on polyethylene pipe, polyamide 11 pipe or new plastic piping materials for the gas industry.

C. Laboratories
Palermo Plastics Pipe (P^3) Consulting will work with laboratories or research organizations to keep abreast of domestic and international standard test methods and standard specifications, and/or write proposals for and then guide research projects for plastic pipe.

D. Litigation Cases
Palermo Plastics Pipe (P^3) Consulting is available for litigation cases involving plastic pipe products, particularly plastic pipe used for natural gas distribution.

II. Dr Gene Palermo

Dr. Gene Palermo received a Bachelor of Science in Chemistry from St. Thomas College in St. Paul, MN in 1969 and a Ph.D. in Analytical Chemistry from Michigan State University in 1973.
Dr. Palermo has been in the plastic piping industry for over 30 years. He worked for the Dupont Company from 1976 to 1995 in the Aldyl “A” polyethylene (PE) pipe business for natural gas distribution. Dr. Palermo developed the initial use of polyamide (PA) 11 for high-pressure gas distribution, up to 300 psig, to replace metal pipe while with Elf AtoChem during 1995 and 1996.

Dr. Palermo was the Technical Director for the Plastics Pipe Institute (PPI) from 1996 until 2003. As Technical Director, Dr. Palermo was chairman of the Hydrostatic Stress Board (HSB) on which he has served for 20 years to develop pressure rating methods for plastic pipe; and chairman of the Technical Advisory Group for ISO/TC 138 for international plastic piping systems. Dr. Palermo has developed standards for plastic pipe and fittings in several standards bodies; ASTM F17, CSA, AASHTO, and ISO/TC 138.

Most of Dr. Palermo’s expertise has been in the natural gas distribution industry. He has been a member of the AGA Plastic Materials Committee for 20 years, the Gas Pipe Technology Committee for seven years, an instructor for the DOT inspector training school for 15 years, and a member of the Plastic Pipe Database Committee since its inception four years ago. Dr. Palermo also developed PPI’s one day Technical Seminar for the gas distribution industry.

Dr. Palermo currently serves as a member of PPI, AGA, GPTC, ASTM F 17 and D 20, CSA, TRB and ISO/TC 138.

III. Awards Received

Dr. Gene Palermo just received the **AGA (American Gas Association) Platinum Award of Merit** from the American Gas Association. This is the highest award given by AGA to its members. Dr. Gene Palermo had previously received the AGA Award of Merit in 1995 in recognition of several presentations made at plastic gas pipe industry meetings, and also serving as moderator at AGA Operations Conferences and Plastic Pipe Symposiums. Dr. Palermo also received the AGA Silver Award of Merit in 2002 for having faithfully and constructively served the American gas industry, and for making continuous and extensive contributions to further the interests and promote the welfare of the gas industry and of the public.

Within ASTM F 17, Dr. Palermo has received two Awards of Appreciation in recognition of his many years of outstanding service and active participation in the plastic piping standards work of ASTM F 17, and a Special Service Award for his many technical contributions and development of plastic piping standards. Dr. Palermo received the Paul Finn Memorial Award in 1995 for his distinguished and continuous service to ASTM F 17 (plastic pipe standards), and particularly for steadfast contributions to the development of sound engineering standards, particularly for plastic gas pipe standards. Dr. Palermo received the Rinehart Kuhlmann Award in 2002 in acknowledgment of faithful and significant contributions in furthering the cause of sound and effective plastics piping standardization. Most recently, in 2005 Dr. Palermo received the ASTM **Award of Merit**, which is the highest award given within ASTM.

Dr. Palermo was also recognized by the US Department of Transportation (Transportation Safety Institute) for outstanding performance as an associate staff in the Pipeline Safety Division in teaching DOT inspectors about plastic gas pipe standards in ASTM and ISO, plastic pipe pressure ratings methods from ASTM and ISO, plastic pipe failure analysis and new plastic pipe materials for the natural gas industry.

IV. Gas Pipe Industry Experience

For over 30 years Dr. Gene Palermo has been primarily involved in plastic piping systems for the natural gas distribution industry. Most of those years were with the Dupont Company where he worked with Aldyl “A” polyethylene gas pipe. He presented several industry papers on the use of the Rate Process Method (RPM) to forecast the life expectancy of polyethylene gas pipe and fittings. At Plastics Pipe XII in Milan (April 2004) Dr. Palermo presented a paper correlating RPM projections with actual field performance for polyethylene gas pipe materials. While with DuPont, Dr. Palermo also conducted several failure analyses of Aldyl “A” polyethylene pipe components and wrote several failure analysis reports for gas companies.

Dr. Palermo was hired by Elf AtoChem in 1995 to develop an all plastic piping system made from polyamide (PA) 11 to be used for high-pressure gas distribution systems as a replacement for metal pipe. He wrote several ASTM and CSA standards for the polyamide 11 piping system. He worked with PPI member companies to develop polyamide 11 pipe, butt fusion fittings, mechanical fittings, meter risers, transition fittings, and valves and also developed a butt fusion procedure for joining polyamide 11 pipe and fittings using the same butt fusion equipment that gas companies use for polyethylene pipe and fittings.

He has been actively involved in the AGA Plastic Materials Committee (PMC) since 1981. He presented several papers at various AGA PMC Winter Workshops. He has provided PMC members with liaison reports for PPI and ISO activities and served as the chairman of the Code, Standards and Regulatory task group for AGA PMC. Dr. Palermo has also been an active member of the AGA Gas Pipe Technology Committee (GPTC) since 1995. He has chaired several projects in the Plastics task group and the Design task group. He is currently a voting member on the Main Body Committee of GPTC.

Dr. Palermo served on the Plastic Pipe Database Committee, which is a joint government/industry committee to develop a database of plastic pipe and fitting failures that occurred in the gas industry. This database will confirm that industry standards for plastic pipe systems used in the gas industry result in outstanding performance for the end user.

More recently, Dr. Palermo has developed a one-day technical seminar for plastic pipe materials used in the gas industry. This seminar is intended to provide a background on plastic pipe materials, primarily polyethylene, to update gas engineers on recent developments in ASTM and ISO standards for the gas industry, and to provide information on new plastic pipe materials for the gas industry. These include polyamide 11 for high pressure gas applications to replace metal pipe, crosslinked polyethylene for niche applications that require increased slow crack growth resistance, PE 100 materials that are considered the next new generation of polyethylene materials and multiplayer pipe for higher pressure gas applications.

V. Plastic Pipe Standards Activities

A. ASTM

1. Dr. Gene Palermo has been a member of ASTM F 17 since 1982, and D 20 since 1999. He has been primarily involved in the following F 17 plastic pipe standards subcommittees:

F17.10 Fittings
F17.20 Joining
F17.26 Olefins
F17.38 ISO
F17.40 Test Methods
F17.60 Gas

F17.61 Water
F17.90 Executive
F17.94 Terminology

Dr. Palermo has served as chairman of F17.94 on Terminology and F17.38 on ISO. He is also a member of the F17.90 Executive Committee for F17. Dr. Palermo is currently the Chairman of ASTM F17 Division I.

2. New plastic piping standards that Dr. Palermo developed or existing plastic piping standards that Dr. Palermo revised include:

- Added 80°C sustained pressure requirements to water pipe standards to assure slow crack growth resistance.
- Revised D 2513 quick burst requirement to be a ductile failure mode for polyethylene gas pipe instead of a minimum pressure because it is more meaningful.
- Developed a new annex in D 2513 for polyamide pipe and fittings
- Wrote a new standard for polyamide butt fusion fittings (F 1733)
- Added 50-year substantiation for polyethylene materials to D 2513 for gas pipe
- Included pressure design basis protocol in ASTM D 2837
- Added polyethylene validation requirement to D 2837
- Included a crosslinked polyethylene pipe material designation code in F 876
- Wrote a new ASTM standard test method for rapid crack propagation based on the ISO standard (F 1583)
- Wrote a new ASTM standard test method for an 80°C notch pipe test based on the ISO method (F 1474)
- Introduced 80°C requirements for polyethylene heat fusion socket fittings (D 2683) and polyethylene butt fittings (D 3261) consistent with ISO TC 138 requirements
- Wrote a new ASTM test method to measure slow crack growth resistance of polyethylene materials used in corrugated pipe (F 2136)

3. Dr. Palermo led an ASTM workshop to review differences and similarities between the ASTM plastic pipe pressure rating method – D 2837 and the ISO plastic pipe pressure rating method – ISO 9080.

4. Dr. Palermo gave a “spotlight presentation” on ASTM F17.38 ISO standards activities during an ASTM Committee Week.

B. ISO

Dr. Palermo was chairman of the Technical Advisory Group (TAG) for ISO (International Standards Organization)/TC 138 for plastic pipe materials for over 10 years and has attended ISO meetings since 1983. As chairman, Dr. Palermo represented the US plastic pipe industry at all ISO/TC 138 meetings. Dr. Palermo also formulated the US position on all standards ballots from ISO/TC 138. Within TC 138, Dr. Palermo was primarily active in SC 2 for water plastic pipe, SC 4 for gas plastic pipe and SC 5 for plastic pipe test methods. Dr. Palermo has provided ISO liaison reports at various ASTM F 17 subcommittee meetings, and also provided ASTM F 17 liaison reports at ISO/TC 138 meetings.

C. HSB and PPI

Dr. Palermo became a member of the PPI Hydrostatic Stress Board (HSB) in 1985 and was chairman of the HSB for seven years. HSB is responsible for establishing the policy for pressure rating of plastic pipe materials in North America. While with PPI, Dr. Palermo continually updated both TR-2 and TR-4. TR-2 is a public listing of the various ingredients that are qualified for the PPI PVC generic formulation. TR-4 is a public listing of the pressure rating of plastic pipe materials obtained using ASTM D 2837. Dr. Palermo was also instrumental in listing the pressure rating of plastic piping materials obtained using the international pressure rating system (ISO 9080) in TR-4. These MRS (Minimum Required Strength) ratings were added to TR-4 in 1999. Under his leadership, the PDB (pressure design basis) for composite or multiplayer pipes and the SDB (Strength Design Basis) for molding materials were also added to TR-4. Dr. Palermo has attended PPI meetings since 1990 and served as the PPI Technical Director from 1996 until 2003.

D. AASHTO

Dr. Palermo has also assisted with revision of AASHTO standards for polyethylene corrugated plastic pipe used in highway applications. His key contribution was development of an ASTM test method to measure the slow crack growth resistance of the polyethylene material used in corrugated plastic pipe. Through a PPI task group, round robin testing was conducted to establish the precision of the test method known as NCLS (notched constant ligament stress). AASHTO now references this NCLS test as a requirement in their M 294 corrugated pipe standard.

E. CSA

Dr. Palermo is a member of CSA (Canadian Standards Association) B137 Technical Committee for plastic piping systems and also a member of CSA Z662 Clause 12 for gas distribution piping systems. Recent projects that Dr. Palermo has chaired are the addition of the MRS (Minimum Required Strength) ISO pressure rating method for PE 100 materials to B137 and the addition of RCP (rapid crack propagation) requirements to the gas pipe standard B137.4.

F. Plastics Pipes Conferences

Dr. Palermo has served on the Organizing Committee for Plastics Pipes XII held in Milan, Italy in 2004, for Plastics Pipes XIII held in Washington DC in 2006 and Plastics Pipes XIV, to be held in Budapest, Hungary in 2008.

G. GPTC

Dr. Palermo has been a member of the Gas Piping Technology Committee (GPTC) since 1995. GPTC provides guide material for the gas industry to comply with US Federal requirements for the gas distribution industry. Dr. Palermo has chaired several projects within GPTC.

H. TRB
Dr. Palermo has been attending TRB meetings since 1999, and has made several presentations at various committee meetings. Dr. Palermo is currently a member of the Committee on Subsurface Soil-Structure Interaction, AFS40.

VI. Plastic Pipe Industry Publications

1. E. F. Palermo and M. Cassaday, “Comparison of Water/Methane Stress Rupture Testing", AGA PMC Workshop (1982).

2. E. F. Palermo, "Aging of Plastic Pipe", AGA PMC Workshop (1983)

3. E. F. Palermo and I. K. DeBlieu, "Aging of Polyethylene Pipes in Gas Distribution Service", AGA Distribution Conference (1983).

4. E. F. Palermo and I. K. DeBlieu, "Compression Ring Environmental Stress Crack Resistance (Pipe) Precision and Accuracy Round Robin", ASTM Quality Assurance Symposium (1983).

5. E. F. Palermo, "Rate Process Method as a Practical Approach to a Quality Control Method for Polyethylene Pipe", Eighth Plastic Pipe Symposium (1983).

6. E. F. Palermo, “Plastic Piping Material", South Eastern Gas Association Meeting (1984).

7. E. F. Palermo and I. K. DeBlieu, “Rate Process Concepts Applied to Hydrostatically Rating PE Pipe", Ninth Plastic Pipe Symposium (1985).

8. E. F. Palermo, “Battelle Slow Crack Growth Test - DuPont Technical Position", AGA PMC Workshop (1986).

9. E. F. Palermo, “Impact Tests on Saddle Fittings to Determine Conformance to ASTM F905”, AGA Distribution Conference (1986).

10. E. F. Palermo, "New ASTM D 2513 Outdoor Storage Requirements", AGA PMC Workshop (1987).

11. E. F. Palermo, “Polyethylene Pipe for Gas Distribution - That Was Then, This is Now”, Irish Gas Association Centenary Conference (1987).

12. E. F. Palermo, “Plastic Pipe/Fitting Failure: Cause and Prevention", Pacific Coast Gas Association Workshop (1987).

13. E. F. Palermo, K. G. Toll, G. T. Appleton, "Using Laboratory Tests on PE Piping Systems to Solve Gas Distribution Engineering Problems", Tenth Plastic Pipe Symposium (1987).

14. E. F. Palermo, “Critical Evaluation of Rate Process Method 'Anomalies’”, AGA PMC Workshop (1988).

15. E. F. Palermo, K. Gunther, and M. Kanninen, "Progress Toward Designing PE Gas Pipe Against RCP (Rapid Crack Propagation)", AGA PMC Workshop (1989).

16. E. F. Palermo, "Large Diameter Plastic Pipe Damage Investigation", Midwest Gas Association Meeting (1989).

17. E. F. Palermo, K. Gunther, and D. VanDeventer, "Squeeze-Off of Large Diameter Polyethylene Pipe", AGA Distribution Conference (1990).

18. E. F. Palermo, “ASTM/ISO Rating Methods – bridging the gap across the waters”, Plastics Pipes IX (1995)

19. E. F. Palermo, “High Pressure Gas Distribution Piping System”, AGA Distribution Conference (1996).

20. E. F. Palermo, “Plastic Pipe Design Equation Update”, AGA Distribution Conference (1997).

21. E. F. Palermo and D. B. Edwards, “An Alternate Method for Determining the Hydrostatic Design Basis for Plastic Pipe Material”, Plastics Pipes X (1998)

22. E. F. Palermo, “Comparison of ASTM and ISO Gas Pipe Standards”, AGA Distribution Conference (2001).

23. E. F. Palermo, “PPI Adopts International Pressure Rating Method for Plastic Piping Materials”, Plastics Pipes XI (2001)

24. E. F. Palermo, “What’s New with ASTM, DOT and ISO?”, AGA Distribution Conference (2003).

25. E. F. Palermo and Jimmy Zhou, “Can ISO MRS and ASTM HDB Rated Materials be Harmonized”, Plastics Pipes XII (2004)

26. E. F. Palermo, “Correlating Aldyl ‘A’ and Century PE Pipe RPM Projections With Actual Field Performance”, Plastics Pipes XII (2004)

27. E. F. Palermo, “High Performance Bimodal PE 100 Materials For Gas Piping Applications”, AGA Distribution Conference (2005)

28. E. F. Palermo and Steve Swanstrom, “Reinforced Thermoplastic Pipe (RTP) for High-Pressure (800 psig) Gas Piping Applications”, AGA Distribution Conference (2006)

29. E. F. Palermo and E. Lever, “Innovative Methodology for Fitting Lifetime Prediction and Process Control by Correlating Rate Process Method Analysis of Molded Fittings with Notch Ring Test Data”, Plastics Pipes XIII (2006)

30. E. F. Palermo et al, “New Test Method to Determine the Effect of Recycled Materials on the Life of Corrugated HDPE Pipe as Projected by the Rate Process Method”, Plastics Pipes XIII (2006)

31. E. F. Palermo, “Using the CRS Concept for Plastic Pipe Design Applications”, Plastics Pipes XIII (2006)

32. E. F. Palermo and J. M. Kurdziel, “Stress Crack Resistance of Structural Members in Corrugated High Density Polyethylene Pipe”, Transportation Research Board (2007)

33. E. F. Palermo et al, “Effect of Elevated Ground Temperature (from Electric Cables) on the Pressure Rating of PE Pipe in Gas Piping Applications”, AGA Distribution Conference (2007)

34. E. F. Palermo and S. Chung, “Rate Process Method Applied to Service Life Forecast of PE Molded Fittings”, AGA Distribution Conference (2008)

35. E. F. Palermo, “What’s New With Plastic Pipes – An Overview”, Plastics in Underground Pipes 2008.

36. E. F. Palermo et al, “Increasing Importance of Rapid Crack Propagation (RCP) for Gas Piping Applications - Industry Status”, Plastics Pipes XIV (2008).

37. E. F. Palermo, “What’s New With Plastic Pipes – An Overview”, Plastics in Underground Pipes 2009.

38. E. F. Palermo et al, “Increasing Importance of Rapid Crack Propagation (RCP) for Gas Piping Applications - Industry Status”, AGA Distribution Conference (2010).

39. E. F. Palermo et al, “Peelable Polyethylene Pipe for Gas Piping Applications”, AGA Distribution Conference (2010).

40. E. F. Palermo, “Use of PE100 with a Minimum Required Strength (MRS) Rating in a Natural Gas Distribution System”, Plastics Pipes XV (2010).

41. E. F. Palermo, “Comparison Between PE 4710 (PE 4710 PLUS) and PE 100 (PE 100+, PE 100 RC)”, Plastics Pipes XV (2010).

42. E. F. Palermo et al, “CHANGES TO CSA Z662 “OIL AND GAS PIPELINE SYSTEMS” TO INCORPORATE HIGHER PERFORMANCE PLASTIC PIPE”, Plastics Pipes XV (2010).

43. E. F. Palermo, “How to Design Against Long Running Cracks in Plastic Pipe for Water Applications”, ASCE (2011).

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 9

January 13, 2009 Staff Memorandum Follow-Up Information Regarding 2005 Incident in Tucson, AZ

0000092367

COMMISSIONERS
KRISTIN K. MAYES-Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

RECEIVED

ARIZONA CORPORATION COMMISSION

DAVID RABER
Director, Safety Division

ORIGINAL

2009 JAN 13 P 3: 02

AZ CORP COMMISSION
DOCKET CONTROL

Staff Memorandum

Arizona Corporation Commission
DOCKETED

JAN 13 2009

DOCKETED BY

To: THE COMMISSION DOCKET NO. G-01551A-07-0504

From: Safety Division

Date: January 13, 2009

RE: FOLLOW-UP INFORMATION REGARDING 2005 INCIDENT IN TUCSON, AZ.

In the Commission Open Meeting held on December 19, 2008 regarding G-01551A-07-0504, Commissioner Mayes requested an update from the ACC Safety Division, Pipeline Safety Section regarding an incident cited in the Recommended Opinion and Order, page 13. This memo is intended to respond to that request.

Background

As a result of an incident that occurred on July 25, 1991 which resulted in one fatality, Southwest Gas Corporation (SWG) was found to be in violation of CFR-49, 192.303, 192.305 and 192.319, all involving proper installation of pipelines.

Subsequent to this incident, SWG and the ACC entered into a Settlement Agreement (Docket # U-1551-91-372 / Decision #57718). The Settlement Agreement required SWG to identify and conduct investigations to determine the condition of all Polyethylene Aldyl HD pipeline in the SWG system. Decision 57718 also required SWG to conduct additional leak surveys, make repairs and replace all pipelines that were originally installed with improper backfill bedding and shading materials.

SWG submitted a plan to the Pipeline Safety Section for approval in accordance with Decision 57718 and began a systematic inspection, repair, and replacement program during 1992. By December 31, 1998, SWG had replaced 74 miles of Aldyl HD pipeline that had been identified as having injurious backfill materials used at the time of installation. SWG also conducted internal camera inspections on a total of 221 miles of 2"and 4" pipeline to check for improper fusions and possible impingement anomalies. A total of 7,016 fusions were either reinforced or replaced as a result of these activities.

Based on Pipeline Safety Section inspections and information provided by SWG it was determined in March 1999 that SWG had completed all tasks associated with Decision #57718. In addition to the pipeline replaced as required by the Order, SWG also replaced 648 miles of Aldyl-A PE, and 105 miles of ABS pipelines based on leak survey results.

Subsequent Incident in May 2005 which was referenced in the Rate Case (G-01551A-07-0504)

In May 2005, SWG responded to a reported gas leak and fire at 1841 S. Campbell, Tucson, Arizona. The incident resulted in injury to one individual as a result of the fire. The individual was transported to the hospital with severe burns.

Larry Ayers, Senior Pipeline Safety Investigator from the ACC Tucson Office, conducted an investigation to determine the cause of the fire. This investigation discovered that the pipeline failure and fire was due to a crack in the Polyethylene Aldyl HD pipeline caused by a rock impinging upon the pipeline. It was also noted in the investigation that the pipeline appeared to have been properly installed using proper trench and backfill materials. The rock impingement may have been the result of excavation activities not related to SWG operations. Following the incident, SWG replaced all remaining Aldyl pipeline in the vicinity of the failure. There were no violations issued to SWG as a result of this incident and the case was closed.

David Raber
Director

Robert Miller
Pipeline Safety Supervisor

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 10

April 11, 2011
Pipeline Safety Forum –
Aging Pipeline Infrastructure

BRIAN SANDOVAL
Governor

STATE OF NEVADA

PUBLIC UTILITIES COMMISSION

April 11, 2011

Honorable Secretary Ray LaHood
United States Department of Transportation
1200 New Jersey Avenue, SE
Washington, DC 20590

Re: Pipeline Safety Forum - Aging Pipeline Infrastructure

Dear Secretary LaHood:

The Public Utilities Commission of Nevada ("PUCN") via its Pipeline Safety Staff has been working with the Local Distribution Companies ("LDCs") in the State regarding the replacement of certain "aging" and "high risk" types of natural gas pipe for some time. To date the PUCN has never mandated a specific pipeline replacement program or enhanced maintenance activities, nor has the PUCN implemented any type of rate surcharge mechanism to facilitate pipeline replacement work.[1] This lack of a need for a mandated pipe replacement program (and rate surcharge) is largely due to the success the PUCN and its Staff have had in working with the jurisdictional gas LDCs to identify pipelines that have high leakage rates, compared to the norm for the state, and then to address the concerns associated with those pipelines in a judicious and cost effective manner.

These efforts over the past 12-15 years have led to PVC and Aldyl A/HD PE plastic pipe being subject to annual leakage surveys outside of designated business districts in excess of the 5 year leakage survey requirement in the code, implementation of integrity management analysis via equations/algorithms to identify pipe that warrants enhanced monitoring or replacement, and extensive replacement of such problematic pipelines.

For example, as of the end of 2010:

1. NV Energy North (Reno area) has replaced roughly 250,000 linear feet ("lf") of bare and coal tar coated pipe, which includes all known bare steel pipe in their system, and expects to

[1] The PUCN currently has a Docket pending before it (Docket No. 11-03029) in which Southwest Gas Corporation ("SWG") is requesting special accounting treatment of costs associated with certain enhanced reliability and PVC pipe replacement projects that SWG is accelerating construction of this year.

complete replacement of its remaining coal tar coated steel pipe in the next 5 to 7 years. With these replacements NV Energy North will be left with a very small amount of pre-1963 steel pipe and none of a vintage prior to 1957. As part of a 2011 general rate case proceeding, the PUCN authorized NV Energy North to begin recovering the first set of costs associated with the replacement of this coal tar coated pipe.

2. The future plan is for NV Energy North to focus on replacing all remaining pre-1963 steel pipe before switching its focus to pre-1967 steel pipe, as all steel pipe installed in 1967 and later had Xtru coat polyethylene plastic coating and cathodic protection ("CP"), via anodes, at the time of the original installation.

3. SWG (Las Vegas and Carson City areas) has replaced approximately 6,400,000 lf of the approximately 9,600,000 lf of PVC plastic mains and services installed prior to 1975. In 1975 SWG switched to PE pipe for its plastic mains and service. It is the hope of the PUCN Staff that all PVC mains and services will be replaced in or around the 2020 time period.

4. SWG has replaced in excess of 250,000 lf of pre-code (pre-7/1970) steel main and services, including all bare steel mains and services.

5. SWG has replaced a significant amount of Aldyl A medium-density PE and Aldyl HD high-density PE installed by CP National in the City of Henderson since SWG acquired the system from CP National in 1991.

6. The PUCN Staff has confirmed that cast/wrought iron or ductile iron pipe was either never installed in Nevada or was replaced long ago. Additionally, no CAB, ABS or PB plastic was ever installed in Nevada, and all bare steel pipe that had been installed has now been replaced.

The PUCN Staff is also now working with the LDCs on a detailed review of the situation with steel pipelines operating at pressures above 100 psig, including distribution piping operating at elevated pressure, low stress transmission pipelines (operating at pressures that produce a hoop stress between 20% and 30% of SMYS), and high stress transmission pipelines (operating at pressures that produce a hoop stress at or above 30% of SMYS). This effort will help define how much and what type of high pressure ("HP") piping there is in the state, the vintage and era of the pipe installations, what level of integrity management planning is being applied to each type of HP piping, and what percentage of high stress transmission piping can currently accommodate the insertion of "smart pigs" and what is being done to increase this percentage.

Additionally, in 2007, the Nevada Legislature passed one of the Country's most aggressive One-Call/Third Party Damage Laws and gave authority for monitoring and enforcing that One-Call Law to the PUCN and its Pipeline Safety Staff. Since the passage of that One-Call Law, Nevada has seen its third-party damage rates drop by more than 80 percent. With third-party damage being the single greatest risk to pipeline infrastructure, Nevada's One-Call law has be instrumental in keeping the public safe and the gas systems in the State operating reliably.

The PUCN appreciates the opportunity to provide input to the upcoming forum regarding the safety and integrity of the nation's pipeline infrastructure.

Yours truly,

Crystal Jackson
Executive Director
Public Utilities Commission of Nevada

Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 11

PG&E to replace more than 1,200 miles of faulty gas piping across California

PG&E to replace more than 1,200 miles of faulty gas piping across California

Oct. 14, 2011

Facing pressure after a leaky plastic gas pipe sparked a fire at a Cupertino condominium complex, PG&E has decided to replace all 1,231 miles of the same type of aging and notoriously faulty pipeline spread across the state.

The massive project will start next month in Cupertino and Roseville -- where the pipe has been involved in recent accidents -- and in St. Helena. Communities across Northern California and in every Bay Area county will be dug up while the job, expected to cost hundreds of millions of dollars, is completed over the coming years.

Unlike the 30-inch steel transmission gas line that ruptured last year, killing eight people in San Bruno, the 2-inch wide plastic pipe that failed in Cupertino six weeks ago is part of PG&E's network of 42,000 miles of distribution lines that deliver gas directly to businesses and homes.

Batches of that plastic pipe, manufactured by DuPont (DFT) before 1973 under the name Aldyl-A, have shown a history of cracking, prompting numerous federal safety advisories dating to 1998.

"This is the oldest vintage. We know it is predisposed to cracking," Jane Yura, PG&E's vice president of standards and policies for gas operations, said in an interview Thursday. "We are looking at what we need to do to remove the risks and run a safe system."

Replacing all 1,231 miles of PG&E's pre-1973 Aldyl-A pipe will take more than three years, Yura said. She said PG&E will go to the California

Public Utilities Commission, probably next year, to ask for a rate increase to cover the cost, which she said the company had not finished estimating yet.

The company also is building computerized maps to digitize 15,000 paper maps showing where the pipe is located statewide. It is building a database to help analyze leaks and find which sections should be replaced first, Yura added. And it will replace some of the 6,676 miles of Aldyl-A pipe built after 1973 in areas with higher-than-normal leak histories, she said, even though that vintage of pipe has not been the subject of federal advisories.

No federal or state law requires PG&E to dig up all of its Aldyl-A pipe. But problems across the country with it have resulted in numerous lawsuits and multimillion-dollar settlements, dating back decades.

"They know they have 1,200 miles of old, worn out, defective pipe," said Jim Findley, of San Rafael, a PG&E gas measurement and control mechanic for 38 years who has raised safety issues about Aldyl-A pipe at PG&E shareholder meetings.

"Sooner or later, this is going to pop up on some attorney's or law firm's screens, and they are going to be going after PG&E for not doing due diligence."

In 2008, a section of an Odessa, Wash., natural gas pipeline made of Aldyl-A pipe exploded, causing a fire that injured two people and destroyed buildings. The faulty pipes were also blamed for a 2003 explosion that killed a Missouri fairgrounds employee. And in 2000, Arizona's Tucson Gas & Electric reached a $25 million settlement, after problems occurred with its Aldyl-A plastic gas pipeline, installed in the 1960s and 1970s.

Locally, PG&E found numerous leaks in pipes at the Northpoint condominium complex in Cupertino after an Aug. 31 fire gutted a woman's home only 15 minutes after she had left.

Then, on Sept. 27, another Aldyl-A distribution line failed under a Roseville intersection, sending flames shooting into the air for seven hours.

Findley called PG&E's new strategy "a positive step" and said it would make PG&E one of the only major utilities in the nation to remove all of its pre-1973 Aldyl-A pipe.

"This will take at least 10 years to get that much pipe out of the ground. And hundreds of millions of dollars," Findley said. "I don't see any way it will be less than $1 billion. There are sidewalks and roads, storm drains, things like that, and you have to work around all of it. Because PG&E hadn't been taking care of business, now they are behind the eight ball."

In 1998, after a similar type of plastic pipe cracked in Waterloo, Iowa, causing an explosion that destroyed a bar and killed six people, the National Transportation Safety Board recommended utilities and state regulators better monitor plastic piping from that era and replace it when they find it to be a risk.

In 2002, and again in 2007, the federal Pipeline and Hazardous Materials Safety Administration issued advisory bulletins warning of "premature brittle-like cracking" in Aldyl-A pipes made before 1973 and urging utilities to review records and more frequently survey the lines for leaks. But under pressure from industry, neither the federal government nor the California Public Utilities Commission has ever required it all to be dug up and replaced.

Attempting to turn the page after last year's San Bruno disaster, PG&E hired a new CEO, Anthony Earley, a former Naval officer who ran a Detroit utility, DTE Energy, and brought in a new executive vice president in charge of gas operations, Nick Stavropoulos, who overhauled gas line safety at utilities in New York and New England. In his prior job, Stavropoulos replaced Aldyl-A piping across New Hampshire.

"This is good news. I'm happy that they are planning to replace it," said Assemblyman Jerry Hill, D-San Mateo, of PG&E's new plans. "I'm troubled by the fact that it took the recent tragedies for them to realize that this needs to be replaced. But I'm happy that they are doing it."

Earlier Thursday, Hill and Assemblyman Paul Fong, D-Mountain View, announced plans to introduce legislation next year requiring the Public Utilities Commission to force PG&E and other utilities to adopt recommendations from the National Transportation Safety Board for improving natural gas pipeline safety.

Hill said he isn't sure how much ratepayers should pay for PG&E's work to replace its oldest Aldyl-A lines.

"I question whether the ratepayers should be held responsible," Hill said. "We paid for that pipe once. I don't know what the life expectancy of that pipe was. But if it was more than 30 years, at least some of the cost should be the manufacturer's or PG&E's responsibility."

Contact Paul Rogers at 408-920-5045.

California not alone

Problems with the plastic pipe, manufactured by DuPont before 1973 under the name Aldyl-A, have been reported across the U.S.

1,231 miles

Aldyl-A pipe fabricated before 1973 still in PG&E's gas distribution network. The company says it will replace all of it.

6,676 miles

Aldyl-A pipe fabricated after 1973 in use by PG&E; this type has not been deemed unsafe, but the company will replace some of it anyway.

How much will it cost?

Unknown, but PG&E gas

measurement and control mechanic Jim Findley said,

"I don't see any way it will be less than $1 billion."

Visit the San Jose Mercury News (San Jose, Calif.) at www.mercurynews.com

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Proposed Protocol for Managing Select Aldyl A Pipe in Avista Utilities' Natural Gas System

Attachment 12

Letter to The Honorable Ray LaHood Secretary, U.S. Department of Transportation

Title: Letter to The Honorable Ray LaHood Secretary, U.S. Department of Transportation
Date: 10/17/2011
Location: San Mateo, CA
Letter
Congresswoman Jackie Speier (D-San Francisco/San Mateo) today released a letter to Secretary Ray LaHood, U.S. Department of Transportation, in which she asks that he direct PHMSA to require natural gas operators to remove pre-1973 Aldyl-A pipe from service.

The letter is below.

###

October 17, 2011

The Honorable Ray LaHood
Secretary, U.S. Department of Transportation
1200 New Jersey Avenue, SE
Washington, DC 20590

Dear Secretary LaHood:

I respectfully request that you direct PHMSA to take immediate action to address the long-known safety risks associated with pre-1973 Aldyl-A plastic pipe manufactured by DuPont. Specifically, I believe natural gas operators should remove this pipe from use in this country.

As you well know this pipe, used in natural gas distribution lines through the nation, has been prone to cracking caused by freezing temperatures and earth movement. Most recently there have been two natural gas explosions in Northern California that involved pre-1973 Aldyl-A pipe. The operator, PG&E, has announced that it will seek approval from the CPUC to replace all 1,231 miles of pre-1973 Aldyl-A pipe from its system. I commend PG&E on this step and am hopeful that it will propel the appropriate response from PHMSA and natural gas operators.

DuPont first issued warnings about the failure aspects of this pipe in 1982 and the NTSB recommended close monitoring and replacement of the pipe when necessary in 1998, following an Aldyl-A pipe explosion that killed six people in Waterloo, Iowa. Finally, in 2007 PHMSA recommend closer monitoring of the pipe, but fell short of putting operators on a removal schedule. The time to get pre-1973 Aldyl-A pipe out of the ground is now.

You, Mr. Secretary, appreciate better than anyone else how unlikely it will be to get Congressional action on this issue anytime soon. Although the NTSB recommendation has been on the books for more than 10 years, Congress has sat on its hands. You can do what 535 members of Congress can't or won't do. You can propose regulations to begin a systematic removal of this flawed and dangerous plastic pipe immediately. I hope you will.

All the best,

Jackie Speier
Member of Congress

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

Overview of

Avista's Project Compass

Avista Utilities

August 2013

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Attachment 6	List of vendors who received the Request for Information document for supporting System evaluation options.
Attachment 7	CONFIDENTIAL – Scoring results from assessment of vendor proposals, per Attachment 5 & 6.
Attachment 8	Overview document of Avista's Request for Proposals for vendor application solutions and services.
Attachment 9	List of vendors who received Avista Request for Proposals, per Attachment 8.
Attachment 10	Avista Project Compass Guidebook.
Attachment 11	CONFIDENTIAL – Scoring results of the assessments of vendor's solution and services proposals, per Attachment 8.
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Attachment 13	CONFIDENTIAL – Voting tallies for final vendor Selections.
Attachment 14	CONFIDENTIAL – Price comparison of final solutions packages.
Attachment 15	CONFIDENTIAL – Final capital budget approved for Project Compass.
Attachment 16	CONFIDENTIAL – Project update for Avista's Board of Directors, February 2012.
Attachment 17	CONFIDENTIAL – Project update for Avista's Board of Directors, September 2012.
Attachment 18	CONFIDENTIAL – Project update for Avista's Board of Directors, February 2013.

I. Summary

Avista Utilities (Avista or Company) is engaged in a multi-year effort to replace its legacy Customer Information System (or System). Research and planning for this effort began in 2010, and the actual work of replacement, which was named Project Compass (or Compass) was begun in May of 2012. The Company's Customer Information System has been in service since 1994, and has been fortified over time by linking it with nearly 100 other software applications and systems to keep pace with evolving information technologies and expanding customer preferences. While this strategy has provided our customers value, the Company has also been mindful that its ability to continue supporting this aging technology is finite. Between 2003 and 2010, Avista and its technology support partner Hewlett-Packard, assessed options for modernizing the legacy system in order to reduce business risks and operating costs while delaying its ultimate replacement. The Company decided in 2010 to commence with the research and planning needed to support the current replacement initiative. During 2011, Avista selected a technology partner to assist in documenting technology needs, and in assessing commercial business applications from leading vendors. Project Compass was formally launched in 2012, and proceeded with Avista's purchase of Oracle's Customer Care & Billing application, IBM's Maximo asset management application, and implementation support from EP2M. A final capital budget was approved for the Project in 2012. The Company and its support contractors are currently engaged in the implementation of these new systems, which involves the complex process of enabling them to support over 3,500 business requirements associated with 200 business processes, and to connect seamlessly with 100 other software systems and applications. In addition, the training programs needed to support these new systems and work processes, are also being developed and tested. Portions of the Maximo application will be enabled in the fall of 2013, and all other asset management and Customer Care & Billing systems will enter service in July of 2014. A final Phase of Project Compass will span a period of 6 to 12 months after the systems are fully in service, to ensure that all technical, training, and process issues that arise are identified, assessed and timely solved.

II. Avista's Legacy Customer Information System

A utility's Customer Information System is one of the most essential business systems enabling the organization's daily operations. For Avista, it supports functions that range from customer calls, to automated service on the phone system or web, access to electric and gas meter information, customer billing, outage management, customer work scheduling and status reporting, ordering construction materials, and managing customer account information. Each of these activities, and many more, is supported by our highly-integrated Customer Information System. Developed in the early 1990's, it's considered a "legacy" System because it relies on key technologies that are no longer manufactured, commercially available, or supported. Like the systems implemented by many utilities of that era, our software applications were designed and developed by Avista staff, and are often referred to as "homegrown." The decisions of companies to 'self build' resulted in part from the then-high cost of commercially available software products, and the desire to tailor systems to their own unique business processes. In 1992, Avista contracted with Electronic Data Services (EDS) to provide enterprise-wide information technology support, including the ongoing development of the Customer Information System, which was placed in service in August 1994.

Architecture of the System

Avista's legacy System is composed of three highly-integrated applications, also known as the Avista "Workplace." As a unified platform, these applications draw information from a common set of master data tables, and form the technology foundation for a network of complex business processes and transactions. A brief description of the applications is provided below.

1. Customer Service – application supports the traditional utility business functions of meter reading, customer billing, payment processing, credit, collections, field requests and customer service orders. In addition, it hosts the single source of customer-related data that is used widely throughout Avista for various other business processes.
2. Work Management – this application supports gas 'trouble' reporting and the electric Outage Management System, and is used to create orders for location services, permitting, and construction jobs, including those requested by our customers and those arising

through the normal course of construction scheduling and operations. In addition, the Work Management system is linked with the Company's Enterprise Procurement System, part of Avista's Oracle e-Business Suite, for the automated ordering and proper accounting of construction materials.

3. Electric and Gas Meter Application – module used to inventory and manage the Company's fleet of in-service electric and gas meters. In addition to hosting the meter data associated with each customer and premise, the system is also used to track each meter and manage the periodic requirements for meter maintenance and testing.

Avista's Customer Information System was developed around then state-of-the-art concepts including 'single source data,' 'subject area databases,' and 'relational databases.' These innovative and powerful tools, based on the 'relational model', organized very large sets of data into a series of normalized tables (or *relations*). Each table represented a certain type of data, such as the street addresses where the Company provided service. Data in these tables could be freely inserted, deleted and edited, and stored much more efficiently than 'linked' databases. In this model, each individual record in every data table was associated with a unique identifier or 'key'. This unique key might represent a single service address contained in the table of address data. But the unique key for this address was also shared by all of the data related to that address that was contained in all of the other data tables. In this way, a service address was linked with all other related data for that address, including such information as the date of meter installation, the meter manufacturer, meter serial number and usage data for that meter, etc.

The System also employed the now ubiquitous 'client-server' architecture. But when implemented in 1994, it was the first utility system in North America to deploy this design. Databases were built and managed for the mainframe platform using IBM's DB2 product, and the application program code was written in the then-mainstream programming language COBOL v2. The COBOL application routines or programs were developed using the CASE tool "ADW", created by Sterling, performed on desktop computers running the IBM OS/2 operating system. The application was designed for the mainframe operating system known as CICS. Another language, Smalltalk, was used to create visual interface for computer screens, and employed the innovative object-oriented programming methodology. Queries of the data tables were enabled by routines written in the language known as SQL. This advanced System allowed the Company's customer service representatives to efficiently access the mainframe applications, and to query, display, edit and manage data in object form on their desktop computer screens.

Keeping Pace with Change

The Customer Service and Electric & Gas Meter Applications were enabled in 1994, and development of the Work Management System application quickly followed. Avista's Workplace was initially integrated with three other business systems, as depicted below in Figure 1.

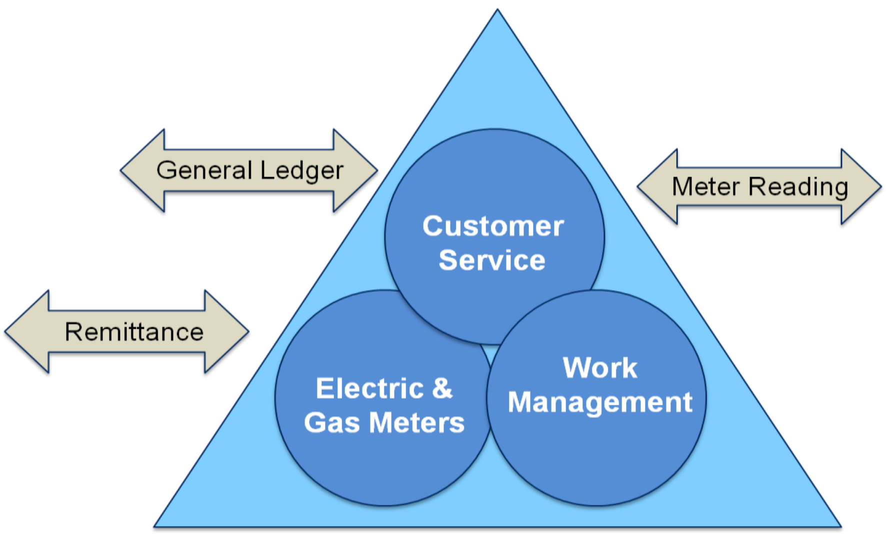


Figure 1. A simplified graphic representing the initial configuration of Avista's legacy Customer Information System, showing the three primary applications and integrated systems.

Change to the System came quickly, however, as wave after wave of new information technologies (such as automated phone systems, powerful mid-range computing platforms, and customer web portals) enabled an evolving stream of new customer service functionalities, embedded as standard features in each new generation of applications developed by leading global vendors. As consumers grew accustomed to these service options in their interaction with a wide range of other companies, they began to expect these types of services from their utilities. Avista worked to accommodate these developments, and in addition, added many features to its System to reduce internal costs by automating paper functions, redesigning work-processes, and providing self-service options for customers. This expanded functionality (such as payment by phone) was accomplished by 'integrating' the legacy System with the emerging applications and systems that enabled these new capabilities.

An 'integration' refers to the sharing of data between computer applications when more than one is required to complete a process. In early integrations, data from one application was sent directly to another application in a direct link known as a 'point to point' integration. The integration relied on a custom computer program to translate the data format and computer language of one application into a form that could be input into the other application for processing, and vice versa. This function allowed the two applications to communicate and work in concert to perform a joint function. Many businesses shared this need to extend the capabilities of the limited architecture of their information systems, and this demand gave rise to an entirely new software product family known as "Middleware." These applications provide communication and management of data for distributed software applications beyond those available from the computer operating system itself. Using a Middleware product known as 'Biz Talk', the Company was able to cost-effectively expand the efficiency, capability and functionality of its legacy System, by integrating new commercial off-the-shelf software, internally developed custom applications, and the application systems of third-party service providers. For both customers and employees, this approach seamlessly integrated technologies far beyond the boundaries of the System's original design limitations. When the System architecture was designed, home computers were uncommon, the internet was in its infancy, there were no e-mail services, no automated phone system, few cell phones, no text or SMS messaging, and no mobile computing, as supported by today's smart phones and tablets. Some of the major applications and systems now integrated with Avista's Workplace include the following:

- Enterprise Voice Portal – this automated telephone system supports a range of self service options for customers, as well as voicemail and other functions used by those contacting the Company and for internal Company operations.
- Mobile Dispatch System – this application supports the call out and scheduling of Avista's gas and electric servicemen, and other field staff required to support Company operations.

- Avista Facilities Management – this application houses the Company's Geographic Information System. In addition to map data, it includes all the Company's electric and gas facility maps and other geographic data.
- Automatic Meter Reading – this system gathers meter-reading data from the Company's fleet of AMR-equipped meters in Avista's service territories in Oregon, Idaho and portions of Washington.
- Construction Design Tool – this application supports the Company's computer-based design tool for gas and electric construction projects, the automated input of component assemblies, materials ordering, and cost accounting.
- Outage Management Tool – this application uses Avista's electric Facility Management and mapping data, in conjunction with electric system device and circuit intelligence, to determine the likely source of a reported outage, to display the likely size of the outage, and to automatically dial affected customers as well as automatically posting outage information on our customer web portal.
- Mobile Web Application – this application hosts our customer's access of Avista's web portal using smart phones and tablets.
- Electronic Check Payment – this family of applications belongs to banks and third-party service vendors used by the Company to support payment options for customers.
- Contract Billing – this family of applications supports services such as customer account management, bill printing, mailing and remittance processing.
- Customer e-mail Support – applications that host e-mail services for our customers, and provide support applications and services.
- Meter Data Management – this recently integrated system provides the data-storage and management capability to enable 'smart metering' capabilities such as customers' real-time use of energy.
- Smart Grid Pilot – this portal provides access for Avista customers participating in the Company's Smart Grid Demonstration Project.
- Avista Web Applications – this system of applications supports the Company's internet website, Avistautilities.com, and enables customers to access and manage their account information held in the Customer Information System.

- Avista's Oracle Financial and Enterprise Procurement Systems – these enterprise applications support the breadth of the Company's financial and reporting systems, as well as a host of enterprise supply-chain functions.

Prudent investments in our legacy system over the past 20 years have allowed us to deliver consistently-high levels of customer service across an expanding range of service channels and self-service options. In place of its initial three modules and three system integrations, the current System supports nearly 200 business processes, and includes approximately 100 integrations with other specific applications and systems, as depicted in simplified form in Figure 2, below. A more complete depiction of the interconnection of major systems is provided as Attachment 1.

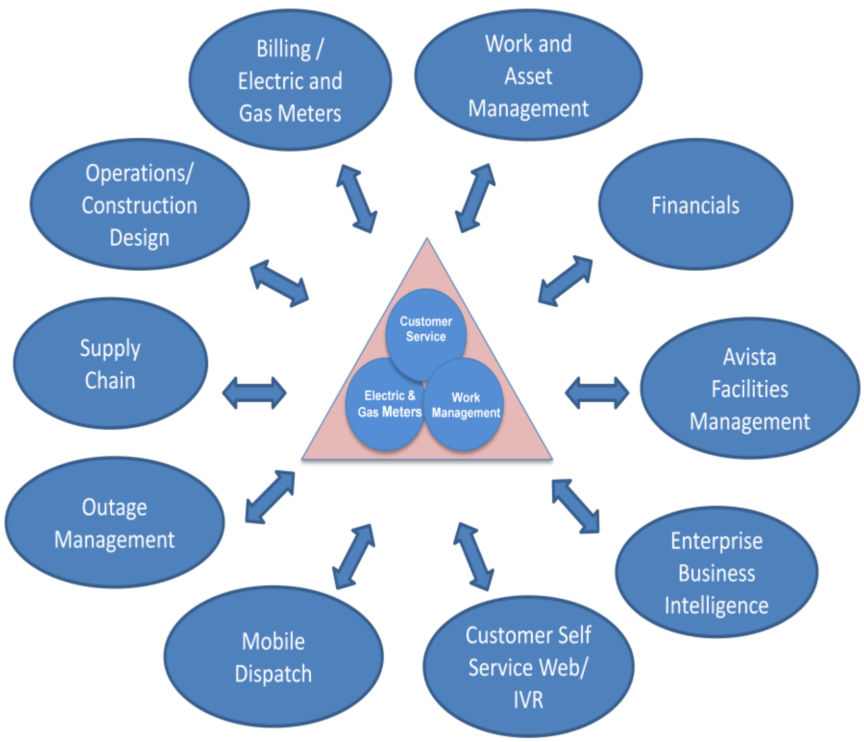


Figure 2. A simplified graphic representing the integration of Avista's legacy Customer Information System with other major applications and systems.

Additional Benefit of Extending the Life of the Legacy System

Avista has invested in its Customer Information System, principally because we could add functionality and value to better serve customers for relatively small incremental investments. But, importantly, this approach also allowed the Company to 'skip over' successive generations of technology platforms, many of which are being replaced by our peer utilities today as they install new contemporary systems. In addition, the Company was able to evaluate the experiences of other utilities engaged in replacing their systems, as one way to support the design of a best practices project. Extending the life of its legacy System has allowed the Company to avoid the significant investment of replacement, and to acquire replacement systems later in the evolutionary trajectory of the technology, giving it broader and more standardized capabilities, and a likely longer future service life.

III. Drivers of the Need for Replacement

As described above, our legacy System meets the basic needs of our stakeholders today because we've made managed investments to extend its value, cost effectiveness and service life. But while there has been incremental and long-term benefits associated with this strategy, there have also been less-obvious but important costs and business risks accumulating with time as the technology platform ages. These latter costs and risks can compete with the benefits of extending the service life, and the Company has remained aware of the inevitability that our core legacy System and the very-complex "patchwork" of integration programs supporting other applications, would have to be replaced.

The Role of Technology Evolution

Over the past twenty years, the rapid evolution of information science technologies has impacted the life-cycle availability of aging software and hardware products and services, and it has enabled significant improvements in consumer service capabilities in each new generation of commercial applications. This rapid cycling of product and service innovation has eroded the foundational integrity of Avista's legacy technology. And at the same time, it has pressured us to continue adding on functionality well beyond the design capabilities of our legacy System.

A Familiar Example

As a way to illustrate the impact of these technology forces, consider a parallel evolution in personal music players. In 1980, Sony introduced the revolutionary and highly-successful Walkman cassette player. Cassette tapes were then dominant, but by the mid-1980s, the Walkman was redesigned for the new format of compact discs (CD). By 1990, cassette players began to disappear from store shelves as personal CD players were continually improved. But, like the cassette tape before, the CD personal music player was doomed when Apple introduced the iPod in 2001. And for some time now, the supremacy of the iPod has been undermined by the iPhone and other smart devices that can store and play music files, but in addition, can access music via web streaming or files stored in the computing cloud.

Today, a person might still use a Walkman to listen to music on existing cassette tapes. But to maintain and expand a cassette music library, requires several electronic components forming a 'chain of technology' that's no longer mainstream. Though cumbersome (by today's standards), it's still possible to perform the steps required to record a new tape, so long as each piece of equipment in the technology chain is working. And the incremental cost is small, compared with the alternative of replacing the tape library with digital files purchased from iTunes. At some point, however, the old equipment will fail. And, because it's no longer mainstream, it will be progressively more difficult and expensive to repair. Even the most ardent cassette person will probably reach the point, where the cost, complexity and limitations are enough to overcome the inertia of reinvesting in a new music platform.

Avista's Chain of Legacy Technologies

The complexity of the technology chain supporting the Company's legacy System is similar in many ways. The key areas of vulnerability and challenge have to do with older computer hardware and operating systems, computer applications and programming languages, and the availability of qualified technical and development support, as briefly described below:

<u>Hardware</u> – As mentioned, our System is based on a mainframe computing platform. This is because when the system was designed and launched, only mainframe machines had the

computing horsepower required for its operation. Even though smaller computers have the necessary capabilities today, the legacy System databases and program applications are entirely mainframe dependent. In addition, the development application used for making programming changes to the Company's System, runs on IBM's OS/2 operating system that has not been sold or supported for many years. And the computers that were matched to the OS/2 operating system haven't been manufactured for a similar time. For several years after the hardware and operating system were discontinued, Avista bought used computer components (some from e-Bay auctions) that were matched with OS/2. More recently, however, the Company uses specialized software that runs on contemporary desktop computers to "emulate" the OS/2 operating system. This workaround allows the Company to execute its OS/2-dependent software applications in a "virtual" OS/2 environment.

Applications and Computer Languages – The legacy software application is the 'computer program' that runs and maintains our legacy system databases, and enables all the features required to support our business processes. These applications are written in the computer language, COBOL v2, which for many years has not been sold, supported, or used in programming applications. This version of COBOL, which we refer to as 'native' COBOL, is also no longer compatible with contemporary mainframe operating systems. To work around this, the Company has for many years used another specialized application, Micro Focus COBOL, to compile the native COBOL language into machine language that is a virtual replication of a more contemporary version of COBOL, which is then able to run on the mainframe operating system. While the virtual COBOL replication has a very high degree of fidelity with the native COBOL, it relies on a visual replication that sometimes results in transcription errors. While the error rate is low, there are millions of lines of computer code that are re-created during the compiling process. The system must be tested to detect these errors, which then requires additional programming time to locate and repair them. More recently, there is a concern that the machine language created by Micro Focus COBOL may not be able to run on newer mainframe operating systems, which now run COBOL v390.

Avista's legacy software applications are almost constantly being repaired, modified (to comply with new requirements), or upgraded with new functionality or capabilities. To accomplish these operations requires use of a CASE tool application known as Application Development Workbench, or ADW. CASE tool applications, whose use peaked in the early 1990s, are tightly coupled with mainframe programming languages; they enable and help-automate the process of generating (writing) code in the native COBOL language. The company that produced ADW is no longer in business, and Avista's application is neither produced nor supported. In addition, ADW can only run on the desktop machines using the emulation software to create a compatible OS/2 operating system. Once the coding changes are made in native COBOL using ADW, they are then compiled using the Micro Focus COBOL application.

Another computer language that's key to sustaining Avista's legacy system is known as Smalltalk. The language is used to create routines or programs that enable many key functionalities of Avista's system, including 'rendering' the display screens customer service representatives use to view and manage customer and system data. Rendering is the conversion of lines of computer code into a visual screen display, which not only allows the user to see account information, for example, but to also make changes to the data or information contained on the rendered screen. This functionality is utterly everywhere today, such as the displays on your smart phone, but it was a very innovative application when designed into Avista's system the early 1990s. And, Smalltalk was the leading programming language of its type in that day. Although this language is a very flexible and powerful tool, it is no longer mainstream, and is no longer sold or supported. Many versions of Smalltalk are still in use among small communities of users in the computer industry, but the language is no longer taught in computer curricula and there is no formal training for new programmers.

Finally, the Company's customer service and system data residing on the mainframe platform must be updated every night in what is known as a 'batch' program. The batch updates the data tables to reflect changes in account status made during the day, and to perform other functions using the data, such as producing customer bills. Like the COBOL routines that enable the interactive use of the Customer Service application (described above), separate COBOL routines are required to perform these batch functions. There are approximately 3,000 individual COBOL programs and millions of individual lines of code in the legacy System. The management, repair and modification of these native COBOL programs can only be performed using the ADW and Micro Focus COBOL applications to both modify and compile them.

People – Maintaining our legacy System requires us to train and maintain technical staff competent in these older programming languages and computer operating systems. This is becoming more difficult as the availability of business analysts and application developers who are familiar with these languages and technology becomes more limited each year. This attrition of skilled developers makes it very difficult to replace members of Avista's support team, many of whom grew up with this technology when it was new, and who either have retired, or are anticipated to do so in the next few years. Since there is no longer technical training or schooling available for these old languages and systems, the Company must train developers in house, which requires a considerable investment to achieve proficiency. It's also difficult to channel younger employees into career tracks that have very-limited and diminishing future application. As a consequence, the need to find, train, and maintain capable technical staff adds another layer of complexity, cost and risk to the maintenance of these legacy Systems.

Other Legacy Considerations

Each of the elements above focuses on an aspect of the Company's System that poses a level of risk greater than that associated with contemporary hardware, operating systems, technical support, and business applications. Avista's situation is not unique, however, and illustrates the general technology principle shared by many legacy systems: that even though they may require complex workarounds to perform their intended functions, which many can do adequately, they are subject to elevated levels of risk that only compound with time. In addition to increasing business and customer service risk, there are other considerations associated with the maintenance of legacy systems like Avista's.

Cost of Modifications – In addition to the risks associated with outdated technology, the System is difficult to modify to add new functionality. This arises because the linkages connecting the applications of Avista's Workplace, along with the Middleware that connects Workplace with the other applications and systems, are 'hardwired' together. Unlike contemporary enterprise applications, when a programming change is made to one of Avista's applications it requires complimentary programming changes to both the connecting Middleware and the other applications themselves. Because the system has been stretched over time so far beyond its original design considerations, these layers of changes have geometrically increased the complexity of the entire system. Each new modification must be adapted to this complexity, and at the same time, it adds to the complexity. Additionally, because the legacy System is used only by Avista, the ongoing application development costs must be borne entirely by our customers.

Ultimate Cost of Replacement – As Avista added new capability to its legacy System, as described above, this required 'programming' to modify the software applications to enable the business processes supporting this new capability. When the legacy System is replaced, the new applications must be 'programmed' to support the same integrated systems and business processes. Generally, then, as the number of integrations in the legacy System increases, so does the cost, complexity and the degree of sophistication required to install the replacement system.

Platform for the Future – In addition to the costs and risks of extending the service life of Avista's legacy system, and the complexity and cost of adding functionality, its ultimate capability has been largely exhausted. The System was designed as a meter-based billing system that provided the Company an efficient and cost-effective platform for managing a customer's basic transactions. In this respect, the system is more 'business centric' because it was designed around the transactional needs of the business. This is not surprising, though, since at the time the System was developed, the transactional convention consisted of customers receiving a paper bill, which they paid with a personal check sent by mail, or in person at one of Avista's offices. Utility customers, generally, had no expectation of being involved in energy choices or service options, which likewise, were rare. Today's information technologies and the market demands for service differentiation have swept aside the business-centric service model and placed the 'customer centric' model front and center. Consumers today have an ever-increasing expectation of being able to conduct business with all manner of companies in ways they, the customer, prefer (e-mail, text, chat, phone), at the time they determine to be convenient (24 x 7 x 365), and to have one point of contact to seamlessly, quickly and efficiently meet all their needs. As capably as Avista's System has performed in the past, it simply does not have the fundamental capabilities required to provide customers the service options they have come to expect in the customer-centric marketplace. In addition, the legacy system cannot support the newer utility product offerings becoming more familiar to customers, such as real-time information management, pre-pay options and time-of-use metering and billing. Some enhancements viewed by customers today as "basic service" (e.g. text messaging or selecting their preferred mode of contact – phone, text, SMS or e-mail), simply cannot be accommodated.

Summary of the Limitations of Avista's Legacy System

The Company's legacy System is dependent on expensive mainframe computing platforms, even though today's mid-range computers have the capability needed to support the applications. It also depends on many obsolete technologies that require complex workarounds to function properly. And the workarounds themselves depend on obsolete systems and applications working properly in concert to enable them. As a consequence, maintaining the system involves risk that grows as the technology ages, and requires expert staff and trained contractors who remain competent in these archaic technologies. Making changes to the System is complex, burdensome, and expensive. But unlike the inconvenience of having to repair a broken cassette player , Avista's system is the hub of business operations for over 600,000 customers, and it must operate flawlessly on a continuous basis. Finally, though the System still operates adequately, there are finite and insurmountable limits to its ultimate ability to provide the technology platform that's needed to serve our customers today and into the future.

Options to Extend the Service Life of the System

Periodically, Avista and its support partner, EDS/Hewlett-Packard, have evaluated the System's capabilities as well as options for its possible modernization. The potential scalability of the Customer Information System was assessed in 1999 to determine the feasibility of expanding the number of customers that could be served with then-current applications, processes and technical infrastructure. The results of this work titled "Avista Workplace Application Scalability Assessment," indicated that with certain investments, the system would be able to support up to 1.5 million customers. As the number of customers served by Avista continued to grow at generally-historic rates, the system investments needed to support greater scalability were neither needed nor made. In 2002, as some of the technologies supporting Avista's System, such as ADW, were becoming unsupported, an assessment was made, titled "Avista Application Migration

Review", of the feasibility of moving the Company's system from the mainframe platform to a contemporary mid-range platform and operating system. The benefits of such a process, commonly known as 'replatforming', were forecast over time and were compared with the estimated costs for completing the work. Results of this work indicated that replatforming the System at that time was not cost effective, and as a result, this work did not proceed. The next assessment was made in 2003 and focused on ways to reduce the risk associated with the ADW application then running on aging desktop computers using the IBM OS/2 operating system. The project report, titled "ADW Conversion", recommended Avista purchase the specialized software to emulate the OS/2 system on contemporary computers and operating systems. This recommendation was implemented. The legacy System was reviewed again in 2006 as part of a larger information technology review conducted for the entire Company. The report, titled "Preliminary Applications Rationalization Assessment", addressed the overall rationalization potential across the Company, and identified any 'modernization' opportunities for specific applications. The term "rationalization" refers to an information technology discipline that's aimed at reducing the ongoing costs of maintaining overlapping or redundant software systems across the whole of the business. The report noted the Company's Customer Information System as a 'high risk' application that was a candidate for either replacement or "refactoring." The latter refers to a process of changing the internal structure of the existing application code to reduce its complexity and improve its readability. While this process helps reduce the risk associated with legacy software, it does not fundamentally change its basic properties or architecture. Refactoring the Customer Service System was assessed as not having sufficient benefit, and the Company was not ready to replace the System. Most recently, in 2010, the Company again reconsidered reinvesting in its legacy System as means to delay its ultimate replacement. As a prelude to requesting vendor proposals to support such an effort, the Company sent a Request for Information to several major information technology vendors to describe the legacy System, and to gauge their interest in participating in possible next steps. A copy of the document, titled: "Request for Information for Avista Workplace Revitalization Project" is attached to this report as Attachment 2. As Avista continued to weigh the possible feasibility of this approach, it ultimately determined that commencing with the research and planning for the current replacement project was the prudent course of action.

Timing of the Replacement

Avista's decision to replace its legacy System involved a number of considerations, many of which have been described above. Considered in concert, these helped shape the decision to commence with the research and planning necessary to support this effort:

- Confidence that Avista could operate the legacy system without fail through at least 2014, without any significant upgrades to older technology. This timeframe would accommodate the period of research, planning, design and implementation of a replacement project;
- Avista expected to have a limited window of availability for the employee and contract technical resources necessary ensure the proper functioning, maintenance, repair, and upgrades of the legacy system expected through 2014;
- The pending need to determine whether or not to renew the long-term (ten years) services contract with Hewlett – Packard for the ongoing mainframe capability, and the maintenance and operations support for the legacy system. The end of the then-current contract presented a window of opportunity for replacing the legacy system;
- The experience that the Company had practically tapped the capabilities of its legacy system, whether or not it was operating on contemporary computer hardware and software;
- The concern that business and service risks associated with the legacy system were continuing to accumulate with time;
- The continuing assessment that as new functionality was added to the legacy system, it was driving geometrically-increasing complexity, and likely greater ultimate replacement costs, and
- The knowledge that the legacy system would not have the capability to deliver some of the service and billing options our customers desired, or service and work-process options.

IV. Planning for Replacement of the Legacy System

Replacements of Customer Information Systems are Common

Nationwide, many utilities have undertaken the same journey in replacing their own legacy

Customer Information Systems, and many are replacing systems installed around the year 2000, a ‘generation’ newer than Avista’s System. Several utilities in the Northwest are among those engaged in some phase of a major replacement project. Avista’s understanding of the status of these efforts is summarized below:

Company	State(s)	Status
Cascade Natural Gas & Intermountain Gas	OR/WA/ID	Currently using Oracle’s Customer Care & Billing application in Oregon and Washington, which replaced their prior system installed in 1999. Planning to install this system in their Idaho service area in late 2014-2015.
Northwest Natural Gas	OR/WA	Currently using commercial system installed around year 2000. Now in the process of evaluating potential for upgrades and/or system replacement in near future.
Puget Sound Energy	WA	Recently placed in service new SAP and Outage Management applications in April 2013. Now engaged in system stabilization.
Portland General Electric	OR	Beginning evaluation phase for the replacement of their customer information and meter data management applications, expected to be completed in next 5 years.
Idaho Power	ID	Planning to place in service a new SAP customer information system in September 2013.
PacifiCorp	ID/OR/WA	Currently evaluating systems for possible installation over the coming five years.
Seattle City Light	WA	Engaged in the early installation work of their recently selected Oracle Customer Care & Billing system.

These Projects also Present a Significant Challenge

Replacing a customer information system is a major undertaking for any corporation. And, it’s particularly complex for an integrated business, such as a utility, that manufactures it own products, constructs and maintains its own distribution and delivery infrastructure, and that often sells more than one energy product in the highly regulated markets of sometimes multiple state jurisdictions. The degree of interconnectedness of the customer information system with the many other business systems and applications supporting the enterprise, is a key driver of the challenge. In addition to the complexity of these systems, there’s significant workload associated with the steps of planning, evaluating, selecting, implementing and testing the new systems, as well as training employees and informing customers in time for a smooth transition. In addition, successful projects have a high degree of executive engagement and commitment, superb information technology competence, a deep knowledge of the company’s work processes – both current and potential future states, and proven experience with the implementation of enterprise information technology projects. The confirmation of these challenges lies in the failure rates reported for these projects, in the range of 40% to 60% over the past five years. In these cases, “failure” was judged as a project that was either abandoned, or that failed to substantially meet its project goals – in terms of cost, solution expectations, implementation timeline or operational readiness.

Identifying Common Challenges

As part of its initial project research, Avista contacted several utility peers who were in various stages of the process of implementing new customer information systems. In an effort to evaluate their preparation, approaches and performances, Avista conducted in-depth interviews to gather lessons learned from these utilities, which included El Paso Electric, San Jose Water, Green Mountain Power and Los Angeles Department of Water and Power.

In addition, the Company took advantage of shared industry knowledge related to the changing demands being placed on utility customer information systems, the maturation of technology solutions, and project audits[1] that assessed root causes of the failure to successfully implement new systems. What emerged from that collective work was a pattern of challenges that had caused many projects to be less than successful. Taking advantage of the opportunity to learn from the experience of others helped Avista prepare, with eyes wide open, for the challenges of replacing its Customer Information System. Some of the central issues the Company and others identified as problematic are included in the list below.

1. Executive involvement that was either distant or faded over the term of the project.
2. Sponsorship of the project that was weak or diffused because there were necessarily so many departments involved in the project.

[1] Focused Management and Operations Audit of Kentucky Utilities Company and Louisville Gas and Electric Company. Final Report presented to The Kentucky Public Service Commission. Liberty Consulting Group, September 12, 2011.

Performance Audit of the Customer Care and Billing System: Testing Prior to Go-Live. Office of the Auditor, Austin, Texas. September 21, 2011.

3. Project management that lacked the applicable experience and strong skills needed to establish a realistic, comprehensive and sustainable plan for the administration of such a large and complex information technology project.
4. Expectations established too early in the project for the ultimate project cost, scope and timeframe, which rendered them unachievable.
5. In spite of the involvement of many departments, project leadership that was often ‘tilted’ toward either the information technology aspect or the business processes.
6. Research to identify best practices and peer-lessons learned that was either inadequate or ineffectively built into the project.
7. Inventory of business requirements that was not complete or that lacked sufficient detail.
8. Business requirements that were not effectively translated into a complete understanding of the application capabilities required to support them.
9. The expertise and effort needed to perform comprehensive evaluations of vendors and their proposals, related to due diligence, project scope and confirmation, was insufficient.
10. Selected vendor solutions often were not complete without additional customized development, which drove added complexity and costs.
11. Implementation support from third-party contractors that had little familiarity with the systems being purchased from the software vendors.
12. Inadequate code testing by the vendor prior to installation in the utility environment.
13. Test environments that did not fully replicate production.
14. The tendency to customize the product solution to better match the existing business processes of the organization, rather than working to implement the solution as designed.
15. An organizations’ resistance to re-design work processes to comport with the architecture of the new solution.
16. Inadequate test team involvement.
17. Inadequate training, education and organizational change management programs to help employees accept and perform competently in new work processes and systems.
18. Going Live with the new systems before the business was fully prepared and production ready.

Designing the Project Around Best Practices

While alarming in some respects, the challenge experienced by many utilities is also not entirely surprising. The process of selecting and implementing a new customer information solution is complex enough by itself, but it is also commonly joined, like Avista's, with the implementation of new asset management or other software systems, and many other work processes. It's also outside a utility's core competency, and it can occur only once in a generation. The degree of challenge and failure has, not surprisingly, given rise to a range of business services whose purpose is to reinforce the capabilities of companies like Avista in the technical and project management skills identified as areas of potential weakness. Avista selected several of these specialized vendors as part of its application selection and implementation processes. Some of the key project-design decisions made by the Company are listed below.

- Established a steering committee of senior executives, meeting monthly with the project directors, to provide executive oversight on all aspects of the design and implementation of the replacement project.
- Made the executive decision to implement what is referred to as "off the shelf" vendor applications, with a commitment to minimize the number of Avista-specific customizations. This approach, while it demands that significant changes be made to the Company's existing business processes during the replacement, helps ensure our customers benefit from the periodic application updates to be provided by the vendor without bearing the cost of the additional software programming that would otherwise be required to accommodate the volume of customized computer code. This approach, which is more mainstream today, is diametric to the approach common when the Company's legacy System was designed and built in house and was carefully tailored over the years to match our existing business practices.
- Created an Avista project leadership structure with two co-directors serving as executive leaders of the effort: the director of customer service, representing the Company's business processes, and the director of application systems programming, responsible for the information technology aspects. The intent of this structure, although potentially ungainly, was to overcome a common failing of projects to 'overweight' one aspect of the project to

the detriment of the other. In addition, both project managers are dedicated full time to Project Compass.

- Hired an outside expert in change management as a Company employee to work full time developing and implementing a communications and change management plan for the project. Avista learned this function was critical to successful companies' efforts to substantially change work processes that accompanied the adoption of off the shelf applications.
- Hired an outside firm to assist the Company in developing a solutions Request for Proposals, in soliciting, comparing, and evaluating proposals from an array of options and potential vendors, and in selecting and purchasing the vendor applications. In Avista's research, this was an area of key challenge for utilities because even the process of understanding the totality of its 'business requirements' was a barrier, let alone the challenge of assessing whether a vendor's application had the full capability to support these requirements.
- Ensuring the vendor selected for supporting the implementation of the customer service and asset management applications, and in seamlessly linking them together, had direct experience and extensive familiarity with the applications selected.
- Retaining an outside project manager with significant expertise and experience implementing enterprise-wide utility software applications – being assigned the broad responsibility for the overall implementation process, including the coordination of project leaders representing the vendor applications selected and those who would be selected for quality assurance monitoring and system testing.
- Identifying and securing the full-time participation of key employees who would be needed full time for the project.
- Securing dedicated office space located away from the distractions of Avista's day-to-day operations, and having ample office and meeting space for all project leaders, employees and contractors associated with the project.
- Retaining the services of an outside firm specialized in creating training programs for new systems, development of the curricula, training the trainers, and evaluating the effectiveness of the training effort.

- Planning for an employee communication program that would be part of the foundation of the Company's change management effort for Project Compass.
- Anticipating the service changes that would arise for customers associated with the new System, and planning for the communications effort that would accompany the Go-Live.
- Waited to establish a final project budget until the planning, preparation and scope had been well enough defined to successfully manage the project.

The Initial Project Plan

The Project was envisioned to be completed over a four-year time horizon, with a substantial effort dedicated to pre-project research and planning. Figure 3, below, depicts the high-level activity phases of this initial plan.

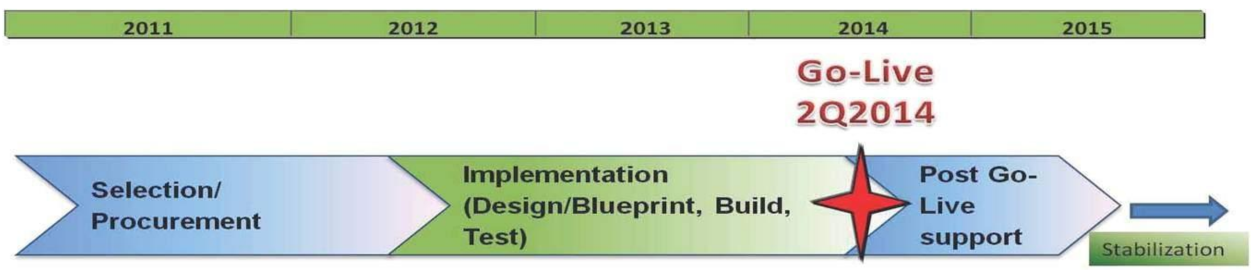


Figure 3. Depiction of the high-level phases of activity envisioned for the Project to replace Avista's legacy Customer Information System.

The first Phase of the Project, known as "Selection/Procurement," encompassed the activities of mapping Avista's business process needs and developing the detailed business requirements for requesting and evaluating alternative sets of software and system solutions that would best meet those needs. This Phase would conclude with the Company selecting the optimized solution set, negotiating final pricing, and signing the purchase agreements with vendors.

Known broadly as "Implementation," Phase 2 encompasses the complex activities of installing and configuring the new vendor software, testing the new systems, and developing and delivering the specialized training modules for the new Systems. 'Configuring' a software application involves the programming required to code its generic capabilities to execute the steps needed to match each of the Company's work processes. In addition, there are many Avista process steps that cannot be executed within the generic capability of the new applications, without customization. This involves the addition of customized programming that is outside the bounds of the 'off the shelf' capability of the application. Significant customization renders the process of installing the periodic vendor updates of the applications, both complex and expensive. Avista is committed to capturing the value delivered by 'off the shelf' implementation, and accordingly, our goal is to minimize the need for customization. What this requires, however, is that Avista organize employee teams to accomplish the significant tasks of developing new internal business processes that can be supported by new application. There is also a significant volume of work required to perform the 'programming' to integrate the new vendor applications with the approximately 100 other applications and systems required to support the Company's customer service and allied business operations. This Phase of the Project also encompasses the development of employee training programs and systems for the new applications, and the extensive testing of the system needed to confirm the technical performance of the new applications as configured to Avista's design. Finally, this Phase concludes with the step of placing the new Systems into service, the "Go-Live."

The third Phase, known as "Post Go-Live Support," encompasses the activities associated with supporting the in-service deployment of the new systems. Key activities include development of contingency plans to respond to issues that may arise during the Go-Live, and providing technical support for the new systems in the period referred to as "system stabilization."

V. Evaluation of Replacement Options

Assessing and Selecting the Replacement Applications

An early step in the work of Selection/Procurement was development of a project charter, which is included as Attachment 3, and outlines the high-level work objectives, some of the key deliverables, and authorizes an expense budget to support these activities. A presentation made to the executive steering committee in April 2011, includes a partial listing of the Project drivers, highlights of Avista's Project research, some key elements of the Project design, planned next steps, and some very-preliminary Project capital costs. This presentation is included as Attachment 4. Later in 2011, the Company named this effort, "Project Compass."

The next key step focused on selecting and retaining a firm to support Avista in developing the following work products:

1) Complete inventory of Avista's technical business process requirements;
2) Inventory of the types of business process decisions to be made;
3) Gap analysis;
4) Request for Proposals document for technology solution providers;
5) Normalized evaluation and vetting of vendor proposals;
6) Selected preferred solution set, including due diligence and scoping;
7) Formal purchase offer for acquisition of vendor services, and
8) Negotiated final purchase price for applications and integration services.

Avista developed a Request for Information to document the services of interest and to gauge the interest of candidate firms, which is included with this report as Attachment 5. [redacted] The Company solicited, reviewed and scored proposals from the participating firms, and a summary of the scores used in making the selection is included as Confidential Attachment 7.

Avista selected Five Point Partners (Five Point) to support its Selection/Procurement activities. [redacted] for identifying every type of major business process requirement that Avista would need from solution and application vendors to support its future business operations. This 'requirements' definition allowed the Company to develop a detailed and specific Request for Proposals from candidate solution providers. Understanding the detailed requirements translated to a more complete understanding of the complexity and cost of the solution sets, as well as understanding up front the activities and applications that would be required for successful implementation, including their costs, and foreknowledge of what parties would be responsible for the associated workload and costs.

Establishing Review Criteria

Global criteria were developed and vetted for use in evaluating vendor proposals. These criteria included: 1) Functionality; 2) Technology; 3) Implementation Partner, and 4) Cost. With the help of Five Point, Avista used the inventories of its business process and decision types to create the Request for Proposals from candidate solution vendors. The solicitation packet was reviewed and refined in several rounds and sent to vendors on September 28, 2011. An overview document of the Company's Request for Proposals for CIS (customer service) and EAM (asset management) solutions, is provided as Attachment 8. [redacted]. An initial step in the vendor's process of evaluating and responding to Avista's proposal solicitation was a conference call opportunity to ask Company representatives detailed questions about its current and anticipated business practices, processes and systems.

Supporting the Application Scoping, Review and Selection Process

During the process of developing its Request for Proposals, Avista launched a parallel effort, known as 'current state mapping', needed to support the design of the Project. This is a comprehensive inventory and evaluation of each of Avista's existing customer information system work processes and system requirements. The purpose of this work was to clearly understand, from a global perspective, every single work process in the business and the applications and systems involved in supporting those activities. In Avista's view, the current state represented a picture of how custom-designed and integrated information technology solutions had been introduced over time to support the Company's legacy service paradigm and work processes. The current-state map included over 200 work processes and over 3,500 individual process steps or system requirements. These process steps represented the necessary technology functions required to support the existing business processes. While these 3,500 requirements were much too detailed to be included in the Request for Proposals, the Five Point STAR process did identify the solution capabilities the vendors would have to meet in order to support Avista's future requirements and business operations. A summary document prepared by Avista, titled "Project Compass Guidebook", is included with this report as Attachment 10, and provides a detailed overview of the complex activities required to support both the procurement of application and service vendors, as well as the detailed process organized to support and execute the current state mapping.

Application Proposals Received from Vendors

Avista received responses from vendors on October 28, 2011, and with the help of Five Point, immediately began the review and evaluation process. The table below lists the vendors who responded and the solutions and roles they proposed for delivering a solution set to Avista.

[redacted]

Most of the responding vendors proposed a complete solution, which included three applications: customer service; asset management; and mobile work management. [redacted], proposed to deliver the complete solution through the primary service known as Systems Integration. This involves the installation of system software applications that are developed and sold by leading global software companies such as SAP, Oracle and IBM, and the integration of these software applications with the other information and process systems of the Company. One [redacted], proposed options where it either provided systems integration services for the software applications of others, [redacted], or a package that included its own software application [redacted]. [redacted] proposed to deliver a complete solution set from three options that included various combinations of software application systems. Two vendors, [redacted], proposed to deliver and install only their own software applications, and one vendor proposed only installation and integration services (no solution applications).

Evaluating the Proposals

In its initial review, Avista's Project Compass team and Five Point evaluated and scored each proposal according to more-detailed criteria, grouped under the four global Project criteria, as represented below:

1. **Functionality**

   a. Minimum Requirements – Degree the solution vendor met the minimum functional capabilities established by Avista. A scoring sheet for this portion of the evaluations is attached to this report as Confidential Attachment 11, pages 1 - 3.

   b. Project Drivers – Degree to which the proposed solution met the system requirements identified in Avista's STAR analysis. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 4 - 21.

   c. Customer Service Fit – Measure of the functionality of the Customer Care, relationship, and billing systems with respect to Avista's needs. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 22 - 28.

   d. Enterprise Asset Management Fit - Measure of the functionality of the asset management systems with respect to Avista's needs. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 29 - 32.

e. Mobile Work Management Fit - Measure of the functionality of the mobile work management systems with respect to Avista's needs. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 33 - 38.

2. Technology

a. Technical Fit – Evaluation of the technical hardware and software needs and costs, and technology implications of the proposals, with respect to Avista's core information technology strategies, in the short and long-term. Scoring sheets for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 39 - 50.

3. Implementation Partner

a. System Integrator Capabilities – Assessment of the vendor's implementation strategy, installation approach, capabilities, timeliness, staffing, and compatibilities with Avista's project plans. The scoring template and assessment notes for this portion of the evaluations are attached to this report as Confidential Attachment 11, pages 51 - 59.

4. Cost

While a vendor's proposed cost was an important element of the initial screening, Avista understood the limitations on the usefulness of these initial costs. Not only were these costs very preliminary, but they did not necessarily represent the package of solutions the Company would select, did not represent the results of final price negotiation, and did not reflect with any degree of accuracy the final cost estimates that would be developed later in the process. The initial costs for each proposal are included in Confidential Attachment 11, pages 60 - 61. Avista's very preliminary estimate of its costs to implement each proposal are included on page 60 of Confidential Attachment 11. The budget line just under the heading titled "Implementation Costs" was the initial very-preliminary estimate of the collective costs to implement each package.

Based on the initial review and scoring of the proposals by the Avista Project Team, the Company withdrew consideration of [redacted].

Avista then conducted day-long interviews in early December 2011 with the final vendors who fully-met the RFP requirements. A Summary Score sheet for the application solution sets from each vendor is attached to this report as Confidential Attachment 11, page 62, The summary scores do not include the evaluations of the capabilities of the System Integration vendors themselves. The remaining vendors, [redacted], were invited to make Product Demonstrations for the Avista Compass team at Avista's offices, conducted over a period of three weeks in January of 2012.

During and after the product demonstrations, Avista and Five Point conducted further evaluations of the vendor proposals rated against a more-detailed list of the Project Compass Drivers, provided below. As Avista's evaluation proceeded, a ranking of the elements of the proposals was created from the aggregation of selections of individual Compass team members. Results were rolled into a Final Solution Workbook where scores for the proposed software applications (customer service, asset management, and mobile), the technology assessments, and the evaluations of system integration vendors were summarized on the basis of meeting the Project Drivers.

<u>Project Compass Drivers</u>

- Technology
    - Agile – ability to respond quickly to the ever-changing needs of the business
    - Reduce technology complexity
    - Strong technology roadmap
    - Minimizes customizations
- Customer
    - Communication preferences
    - Choices – service options
    - Improve customer touch points
    - Develop new ways to deliver more value to the customer
    - Improved information (business analytics) access and availability
- Future
    - Smart Grid
    - Energy Efficiency Programs

  - Real time billing
  - On-bill financing
  - Strong product roadmap
  - Customer experience
- Employee
  - Employee impact – positive benefits
  - Minimize adverse impact to employees
- Business
  - Business process efficiency and effectiveness
  - Trusted System Integration relationship
  - Strong System Integration implementation approach, methodology and experience
  - Preserves data integrity
  - Meets project budget, scope and timeline
  - Eliminate silos of information
  - Improved information (business analytics) access and availability
  - Satisfies current regulatory and business requirements

The Final Solution Workbook is included in this report as Confidential Attachment 12, and records the numeric scores derived from the initial evaluation of the vendor proposals.

[redacted]

[redacted]

Avista's Final Selection of Applications and Services Vendors

In Avista's final analysis, it determined that the best overall combination of solutions for serving its customers would be a hybrid of the solution sets proposed, including the Oracle Customer Care & Billing solution, installed and integrated by EP2M, and the IBM Maximo Asset Management solution installed and integrated by IBM, in partnership with EP2M. In addition, Avista determined it was in the interest of its customers to delay the selection and implementation of the Mobile application at that time, since a new version of [redacted] will be available for review in 2014. Final voting scores for the candidate customer and asset solutions, the lead solution integrators, and the combined projects, are included in this report as Confidential Attachment 13

<u>Oracle's Customer Care & Billing</u> application was ultimately selected [redacted] because it met all the solution requirements needed to serve our customer and business needs, is more tailored to utility industry applications, was much more intuitive for customers and our employees to navigate and use. It is also compatible with Avista's existing Oracle financial and procurement systems. [redacted]

<u>IBMs Maximo Enterprise Asset Management</u> solution was selected [redacted] because it was judged to have the strongest overall capability for Avista, is an industry leader, integrates well with Avista's geospatial facilities technology, provides for the incorporation of fleet, facilities and enterprise technology assets, and provided the opportunity for early installation of Avista's electric generation assets. In addition, IBM was willing to partner with EP2M in the installation and integration of its Maximo product.

EP2M was selected as the System Installation/Integration vendor because it has a great depth of familiarity and experience with the Oracle Customer application, has an excellent track record of successful project completion, received excellent customer reviews, has very low employee turnover and has excellent utility experience.

This combination of vendors and solutions, together, was judged to provide Avista and its customers with the optimized products and services that would deliver excellent service and value, in both the short and long term, and at the lowest overall price. During the final selection process, Avista prepared a comparison of the very preliminary pricing, as derived through the course of the evaluation process, for Avista's selected solution, as well as the second choice solution set [redacted]. These prices were very preliminary because the final pricing for the selected solutions had not yet been negotiated. In addition, because these costs did not reflect all of the activities involved in replacing the legacy System, they were not intended to represent a budget estimate for completing the Project. The costs used to compare the final solution sets are included as Confidential Attachment 14.

VI. Implementation of the Replacement Systems

Avista's initial project research and its planning work with Five Point Partners, to assess its business process requirements and to evaluate a range of proposals, provided the base of knowledge and certainty needed by the Company to proceed with the replacement of its legacy System. Avista entered final negotiations with the selected vendors, described above, and executed purchase agreements in May 2011. [redacted].

Project Compass Capital Budget

A final project budget was developed over the course of 2011 and 2012, for the implementation of the Company's customer service and asset management applications. This budget was approved by the Company's executive steering committee on December 6, 2012, and is included as Confidential Attachment 15.

Timing of the Final Project Budget

Although Avista discussed potential costs of the project early in its inception, and approved preliminary budgets through the course of Project development, it did not establish a final capital budget until the Project was well-enough defined to do so with confidence. Avista has learned from its own experience, through its peer utility interviews, and from the support and advice of outside experts, that organizations commonly undermine the success of their software projects by making cost commitments too early in the development stages. This mistake undermines predictability, increases risk and project inefficiencies, and generally impairs the ability to manage a project to a successful conclusion. Early in the scoping of a software project, particular details of the application being designed/installed, a detailed knowledge of the Company's specific business requirements, details of the solution sets, the management plan, identified staffing needs, and many other variables are simply unclear. Accordingly, estimates of the potential cost of the project are highly variable. As these sources of variability continue to be investigated and reduced, the project uncertainty decreases; likewise, so does the variability in estimates of the project cost. This phenomenon, widely discussed in the literature, and often associated with author Steve McConnell[2], is known as the "Cone of Uncertainty," presented in Figure 4[3], below.

[2] Software Estimation: Demystifying the Black Art. Steve McConnell, Microsoft Press, 2006

[3] id. Figure 4.2, 96.1/751.

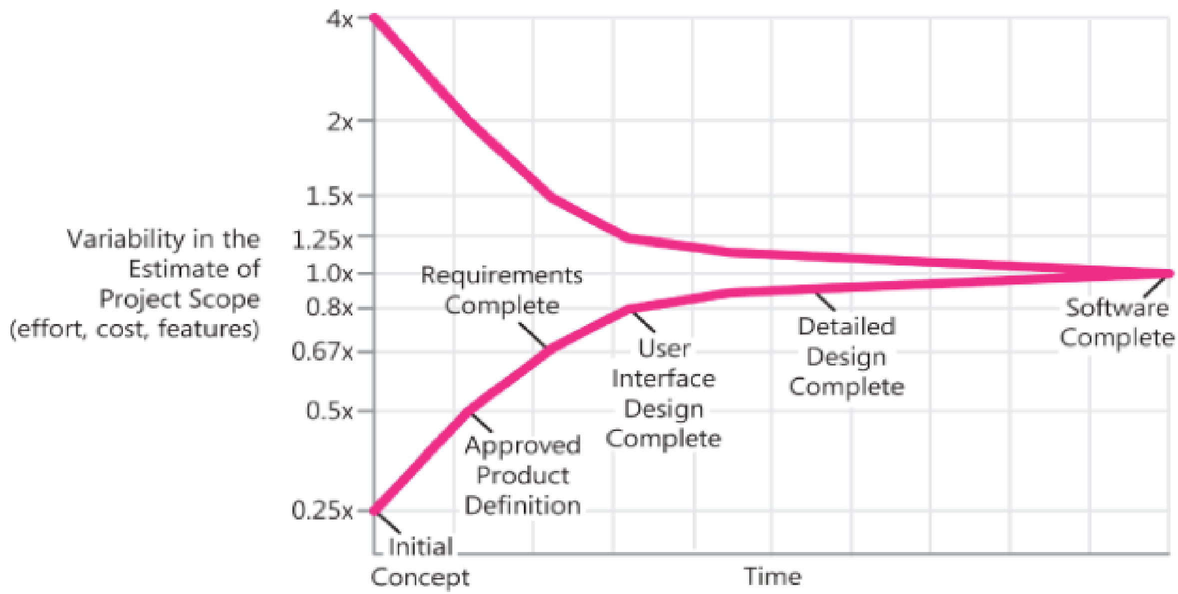


Figure 4. The 'Cone of Uncertainty' describing the relationship between the variability in the estimates of a software projects' cost and the stage of the project at which the estimates are developed.

As the figure illustrates, significant narrowing of the uncertainty generally occurs during the first 20-30% of the total calendar time for the project. The uncertainty will only decrease, however, through active and deliberate project research and design required to further define the scope, requirements, implementation details and estimates of component costs. And, this uncertainty must continue to be constrained throughout the course of the project by the use of effective project controls.

The Role of Cost Information Early in the Project

The decision point for the Company in 2010, was whether to significantly reinvest in its legacy technology, as the means to defer its ultimate replacement, or instead, to invest in the planning and exploration of options needed to support its current replacement. In moving toward the latter, the Company's focus was to assess its needs, evaluate options, and select a set of solutions that would meet the long-term needs of the Company and its customers at the lowest possible cost. At that point, the Company engaged in the progressive stages of project design needed to prudently define its likely scope and potential cost. Through this work, uncertainty around the project was narrowed and potential costs were further refined, to the point that Avista was confident purchasing the selected applications and proceeding with the work of implementation. Even though this was several months before the final budget was approved, Avista had by this time built the foundation needed to initiate a successful project: the ability to deliver a solution that would meet its long-term customer service and business requirements in an optimized approach, and in a manner that would achieve the least cost for its customers.

The Project Budget as a Management Tool

While Avista believes its estimates of scope, timeline and budget for the project are reasonable, and it is committed to control the Project to best meet each of these estimates, it is also cognizant that its success will not be defined by whether or not each estimate, including the budget, is precisely met. In contrast with a ‘not-to-exceed’ metric, the software budget is a management tool that allows senior leaders to make informed enterprise-level decisions, and that provides an effective tool for the project manager to control project activities in an effort to meet the estimates of each deliverable (timeline, scope, functionality and cost). In describing the relationship between software project estimates and final results, McConnell states:

> “The primary purpose of software estimation is not to predict a project’s outcome; it is to determine whether a project’s targets are realistic enough to allow the project to be controlled to meet them.”[4] “Typical project control activities include removing noncritical requirements, redefining requirements, replacing less-experienced staff with more-experienced staff, and so on.”[5] “In practice, if we deliver a project with about the level of functionality intended, using about the level of resources planned, in about the time frame targeted, then we typically say that the project "met its estimates," despite all the analytical impurities implicit in that statement. Thus, the criteria for a "good" estimate cannot be based on its predictive capability, which is impossible to assess, but on the estimate’s ability to support project success…”[6]

Avista believes it has designed and developed such an implementation plan and budget for Project Compass. By this, we mean that the overall Project record will demonstrate its proper research and design, robust planning and estimating, effective management and controls, and that its delivered scope, timeline and cost, are reasonable, cost effective and prudent.

[4] id. At 42/751.
[5] id. At 39/751.
[6] id. At 41/751.

Project Budget Allocation

The overall allocation of the final capital budget for the Project is shown in Confidential Attachment 15. The budget amounts represent key purchases and contract and employee labor required to support the activities of installation. In addition, these costs are also separated for each major application system: Customer Care & Billing; Maximo for Generation Resources, and Maximo for Gas and Electric Transmission and Distribution assets.

Application Costs as a Portion of the Overall Project Budget

Today, the cost to purchase the rights to enterprise commercial applications is a relatively small proportion of the overall replacement project budget. This is because the vendor’s cost of developing and updating these huge applications can be spread across a broad global client base. Accordingly, the incremental cost to each company is relatively small. To achieve this broad applicability, the software applications are designed with a standard off-the-shelf range of functionalities, which allows them to be adopted by the widest possible client base. But, since every company still has unique business processes within these broad templates of standard functionality, the applications are designed with significant additional flexibility that is not configured when the application is purchased. This configuration must be performed by each company after the application is purchased and installed, in the ways that best meet their individual business requirements. For Avista, as described above, tailoring the applications to meet our 3,500 individual business requirements involves a significant labor cost. In addition, the customer service and asset management applications must be integrated to perform seamlessly with each other, and with every other business software application (over 100 for Avista) that’s required to support the operations of the Company. Finally, for each existing Avista work processes that cannot be accommodated by the standard functionality of the new applications, this work process must be re-designed so that it can. This process re-design is also labor intensive because it’s performed by work teams staffed with employees representing every segment of the business that’s impacted by the change. Overall, these costs of installation, configuration, integration and work process re-design represent the lion’s share of the project budget.

In addition to the activities above, there is a broad range of other support required to make the Project successful. These include development of training materials for employees on the new systems and the re-designed work processes, the process of training, project change management, employee and customer communications, project quality assurance, computer hosting and computer hardware for the applications, and providing technical support for the new systems at their launch and during the period of stabilization.

Board of Directors Updates on Project Compass

The Finance Committee of the Board of Directors was provided an overview and update on the progress of the Project by Mr. James Kensok, in February 2012. A copy of that presentation is included as Confidential Attachment 16. Mr. Kensok provided another update to the Board Finance Committee in September 2012, and that presentation is provided as Confidential Attachment 17. The Board Finance Committee received an updated progress report on Project Compass, made by Mr. Kensok, in February 2013. A copy of that presentation is included as Confidential Attachment 18.

Principal Implementation Activities of Phase 2

As briefly described above, the major activities of the Implementation Phase include installing the software solutions and configuring them with Avista's System, testing all of the System components prior to deploying the solution, developing and implementing employee training and customer and employee communications. And, finally, the Go-Live placement of the new System into service. Some of the key activities include:

- Tailor / Configure the software solutions to match the design of Avista's business requirements.
- Develop Technical Specifications – These ensure the software configurations can be documented for future development and upgrades.
- Develop / Configure Work Processes – documents how the Company has determined that the flow of work processes will be accomplished using the new software.
- Develop Integrations – to connect with Avista's other business systems and applications.

- Develop Data Migration Plans – to move Avista's customer and other data to the new platforms.
- Security Setup – Establishes the security plan for protecting the Company's customer and other data.
- Test Scenarios – developing test scenarios from an inventory of the processes to be tested, using the step-by-step procedures for each particular transaction or business process that will be used to integrate and test new systems.
- Conduct Unit Testing – unit testing ensures that underlying customized portions of the software systems are functioning as designed.
- Migrate Data Tables and Files – to ensure there is order and accuracy when information is moved from the programming stage into the testing stage and, finally into live application.
- Evaluate System Test Application – the performance testing of the system created for testing the actual applications and their integrations.
- Conduct Systems Integration Testing – focuses on the testing processes between the software solutions implemented, and the Company's other systems, including third party systems.
- Conduct User Acceptance Testing – provides those who will actually be using the systems to evaluate all application functions related to their business processes. Acceptance testing confirms the system meets business requirements, and also, verifies the business processes for the software solution are complete, well understood, and well documented.
- Defect Management – During each test cycle, actual test results are compared with expected results. If issues are identified and logged, functional and/or technical updates will be made as required to resolve a particular issue. As issues are resolved, additional testing is completed to validate that the issue is fixed properly. The majority of this testing falls within the test cycles outlined above, but additional testing is completed as required by the project team until all business requirements, system functionality, integrations and business processes are fully tested.
- Training Materials are created for employees and others who will be using the system.
- Train the Trainer courses are conducted for employees who will be key trainers for others.

- Deliver Training – Training is one of the final opportunities to prepare employees to operate the system with the new business processes. The timing of the training is critical so that the users are trained in time for the transition, but will still retain knowledge of the new system.
- The project team develops the detailed "cutover plan", to ensure a comprehensive list of supporting requirements is timely developed. 'Cutover' refers to the process of moving Avista's service from the legacy operating systems to the new applications and systems.
- Ensuring that the technical operating environment for the new is in place and stable prior to the Go-Live.
- An assessment of organizational readiness is conducted to ensure the Company is equipped for a successful Go-Live.
- In conjunction with preparing for the Go-Live, a contingency plan will be developed and in place to respond to issues that may arise during the process.

In addition to the major activities listed above, the work in this Phase is also organized and managed in several project 'workflows' that provide a unified objective and continuity across this Phase. These six workflows include:

- <u>Overall project milestone plan</u> – this body of work supports the management of the overall project.
- <u>Enterprise Asset Management /First Wave</u> – this effort is focused on the application of the new asset management software to Avista's electric generation and substation equipment.
- <u>Enterprise Asset Management / Second Wave</u> – this portion of the project encompasses the activities required to apply the new asset management software to the Company's electric transmission and distribution, and its natural gas infrastructure. This work process replaces the functionality currently provided by Avista's legacy work management and electric and gas meter application systems.
- <u>Customer Service Application</u> – This portion of the program, which represents the lion's share of project Compass, is focused on replacing the functionality of Avista's legacy customer service system.

- Testing – This workflow is focused on the technical testing of the new applications, as integrated into the Company's business environment. Activities include the technical testing of the software and hardware systems, and what is known as user-acceptance testing. The latter involves Company employees testing the new systems by simulating all possible combinations of their business application.
- Enterprise Technology – Ensuring the new applications mesh technically and strategically with the Company's enterprise services model for information technologies.
- Organizational Change Management and Communication – This work involves the preparation of employees for their successful participation in work process redesign efforts, and for the systemic changes they will experience when the new systems are implemented. In addition, there is an important element of this work that is focused on the customer: preparing them in advance for the minor service changes that will accompany the launch of the new systems.

Key Activity in Phase 3

After the Go-Live, there is a transition when supporting consultants remain on site to help resolve technical issues that arise, in the Phase known as Post Go-Live Support. The duration of this transition period, which is expected to last between 6 and 12 months, will be defined by Avista's internal support personnel as they become comfortable supporting the new system.

Attachment 1

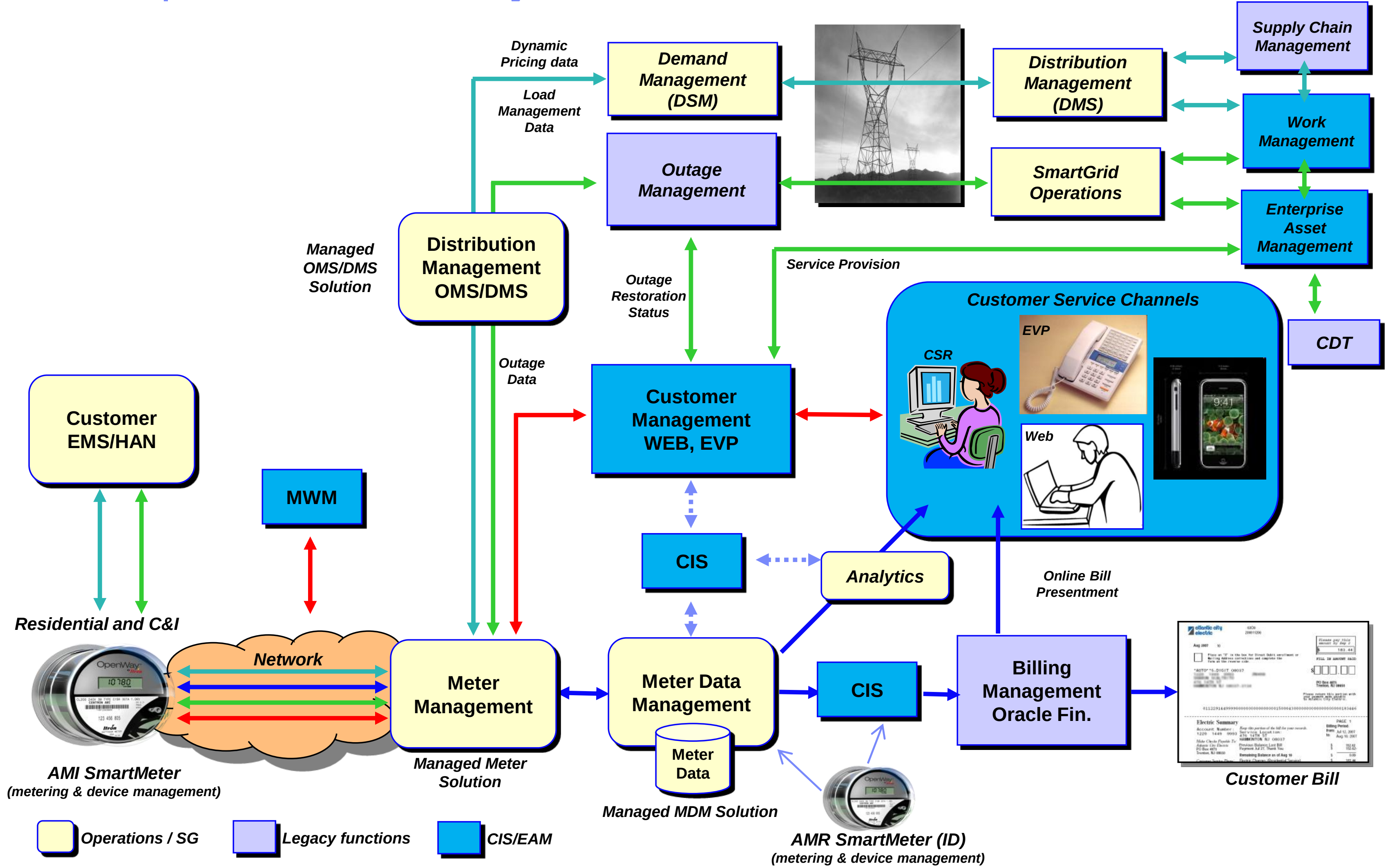
BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

Conceptual Business System Model – CIS/EAM



Attachment 2

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

November 6, 2009

RE: Request for Information for Avista Workplace Revitalization project

Dear Consultant:

Avista desires to update its legacy application that comprises its Customer Service System (CSS) Work Management System (WMS) and Electric and Gas Metering Application (EGMA) for asset management. This Request for Information letter ("RFI") outlines Avista's current situation and is requesting sufficient specific information to value various options regarding the upgrading and re-platforming of these various systems. From the information gathered under this RFI, a Request for Proposal (RFP) will be developed for a specific set of alternatives. Additional discussions may be held with respondents to refine the alternatives before the RFP is completed and released.

It is Avista's intention under this RFI to solicit information regarding alternatives to extend the life of Avista's existing CSS, WMS and EGMA applications as further explained in this RFI. Upon conclusion of this RFI, it is Avista's intention to send out an RFP with the information gathered under this RFI for further detailed information regarding Consultant's qualifications, skill set, company information, etc. with the intention of selecting a vendor to perform the re-platforming of Avista's CSS, WMS and EGMA applications.

Avista's CCS, WMS and EGMA applications were developed in the same development and execution environment. They are mission critical and highly integrated systems both with each other and other enterprise applications.

The applications execute in both online and batch environments. The online application is delivered to approximately 300 users across roughly 30 locations. The batch system executes in a traditional IBM z/OS JES environment, using CA 7 to schedule and execute JCL and COBOL programs. Development for the batch system uses an outdated code generation tool, Knowledgeware's ADW. The online system is front-ended by a Visual Age Smalltalk client that ties to a DB2 backend through a small number of CICS transactions calling a number of COBOL subprograms providing a data access layer. Details are provided below.

There are a significant number of smaller pieces of functionality and integrations at multiple levels. This functionality will need to be supported natively or migrated to updated environments.

Avista requests information on the various alternatives to extend the life of this system. We require an environment that would support an eight year life span with reasonable investment in on-going sustaining work. We are initiating this project to reduce on-going expense in the execution environment (hosting costs) and revitalize the software platform. Alternatives could include re-siting or re-platforming the system in any layer to support easier development or execution environments. For example, a migration from DB2 to Oracle, the primary database for all Avista's other execution environments might be proposed.

Additional information regarding Avista's current system for your reference in responding to this RFI includes the following Functional Requirements:

7x24 Operations with a nine hour weekly maintenance window

1:1 Functional Equivalence including inter-system integrations with no end-user retraining required

Current system

Mainframe Hardware platform	IBM Z Series
Mainframe OS	Z/OS
4 hour average peak MIPS	Approximately 200
DASD	Approximately 145GB
Tape storage	90,000GB
Network Environment	TCP/IP
OLTP Monitor version	CICS 6.5.0 3 regions
Workstations	PC w/ fat client application
Database	DB2
Security Application	RACF
Print lines	Approximately 250,000
Printing management	Barr Systems
Query / Reporting tools	PRF DYL280
Online users	300+
Number of JCL Batch Jobs	Approximately 1200
Number of Batch steps	Approximately 11,000
Lines of code Batch COBOL	Approximately 8 million
Number of Batch COBOL programs	Approximately 800
Batch COBOL development tool	Knowledgeware ADW
Number of REXX scripts	78
Number of TSO CLISTs	67
Job scheduling environment	CA7
Job execution environment	JES2
Third-party sort utilities	SyncSort
Other utilities	WAAP, WAAS, Easytrieve, Endevor, Move for DB2, SPUFI

Data access layer facts

Number of CICS transactions	Approximately 10
Lines of code in data access subprograms	Approximately 4 million
Number of data access COBOL subprograms	Approximately 1000

Database Facts

Number of tables	Approximately 700
Total database storage	Approximately 200GB
Number of stored procedures or triggers	0

Please note that this RFI contains information that is confidential and proprietary to Avista. Consultant shall under no circumstances use the information contained herein for any purposes other than the evaluation of the requirements of this RFI and the preparation of a response to this RFI. Consultant agrees to not disclose the information contained in this RFI to any third parties and shall limit the distribution of this RFI to any third parties and shall limit the distribution of this RFI to those employees of Consultant who have a need to have access thereto for the purposes of evaluating the requirements of the RFI and preparing a response thereto. Consultant shall employ the same degree of care in preventing the unauthorized release of the information in this RFI to a third party (or parties) as it uses with regards to its own confidential information, provided that in no event shall Consultant employ less than a reasonable degree of care and Consultant shall inform its employees of the foregoing obligations. Likewise, Avista agrees to employ the same degree of care in preventing the unauthorized use of the information supplied by Consultant in response to this RFI to a third party (or parties) as it uses with regards to its own confidential information and Avista agrees to inform its employees of the foregoing obligations as well.

Additionally, any costs and expenses that may be incurred in connection with the preparation and submission of a response to this RFI shall be the responsibility of Consultant.

If your company is interested in participating in this RFI, please contact Pat Dever on or before November 18, 2009 with the purpose of (1) confirming that we have the right contact information for your firm and (2) to ensure that those planning to respond can be communicated with to receive any supplemental information or clarifications which might be issued prior to the proposal due date. Meetings will be scheduled during the days of November 19th – 30th for a conference call to discuss Consultant's questions in response to this RFI.

We appreciate your time and attention to this matter and look forward to hearing from you soon.

Sincerely,

Stacey M. Levin
Senior Contract Manager
Corporate Contract Services
Avista Corporation

Vendor List
RFI No. R -36462
For Workplace Revitalization project
Due November 19, 2009 to begin discussions

Oracle
Thiago Sachs
thiago.sachs@oracle.com

HP
Bob Marshall
Bob.marshall@hp.com

Microsoft
Andrea Dunn
Andrea.Dunn@microsoft.com
and
Michelle.Peterson@microsoft.com;

~~Alliance Data~~
~~Jim Will~~
~~James.Will@alliancedata.com~~

Jacob Miller
Sr. Client Representative
IBM Sales & Distribution
office 206-587-6775
mobile 206-859-0817
jacmille@us.ibm.com

Accenture
161 N. Clark
Chicago, IL 60601
fax: 312-652-5900
Trey Thornton
thornton@accenture.com

WI Pro
Aravind Kamath
aravind.kamath@wipro.com

Freddy Yendrembam
Energy & Utilities Practice
HCL Technologies Ltd.
Freddy_Y@hcl.in

Infosys
Sales & Marketing
Sanjeev_Bode@infosys.com

~~Accent Business Services~~
~~Jeff Tomkins~~
~~marketing@accent-inc.com~~
~~or~~
~~Dave Chaney~~
~~david.chaney@accent-inc.com~~

Fujitsu America
SKratz@us.fujitsu.com

September 8, 2010:

NO AWARD notices were sent to the following vendors on 09/08/10 per Pat Dever's request:

1. thiago.sachs@oracle.com
2. Michelle.Peterson@microsoft.com and Andrea.Dunn@microsoft.com
3. jacmille@us.ibm.com
4. Freddy_Y@hcl.in
5. aravind.kamath@wipro.com
6. trey.thornton@accenture.com
7. Sanjeev_Bode@infosys.com
8. greg@continuitysource.com;
9. SKratz@us.fujitsu.com
10. david.chaney@accent-inc.com

Attachment 3

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

Attachment 3

INITIATION PROJECT CHARTER

1. General Project Information

Project Name:	**CSS Replacement Market Analysis – CSS Replacement Initiation Phase**
Project Sponsors:	**Jim Kensok, Don Kopczynski, Roger Woodworth**
Steering Committee:	**Christy Burmeister-Smith, Jim Kensok, Don Kopczynski, Kelly Norwood, Jason Thackston, Roger Woodworth,**
Project Manager:	**Jana Leaf (oversight by Pat Dever and Vicki Weber)**

2. Accounting

Type	***Mark One***
Capital Project	
O&M Project	*X*

3. Project Definition

What is the product or service?	Work with internal stakeholders and external consultants to review the current options for Commercial off the Shelf software replacement for our legacy Customer Service System with an eye towards replacement of our Work Management System and Electric and Gas Meter Application.
Who benefits? How?	Avista will benefit from Initial Phase by learning what options are available to meet our current and future business needs. Avista and its customers will also benefit by replacing legacy mainframe system that is obsolete (20 year-old technology) and has limited functionality to meet our future customer needs. Software development resources are becoming more difficult to secure (COBOL, CICS, Small Talk), thereby increasing the risk associated with operating & maintaining this system as a core Customer Service and Billing System of our business.
We will consider an abbreviated process if we are able to select an existing platform strategy. This process could change steps 3 – 5.	<u>**Deliverables:**</u> 1. Hire consultant(s) to assist in: a. Developing business and technology requirements b. Evaluating alternative commercial packages c. Conducting evaluation criteria workshops d. Examining optionality for segmenting customers e. Evaluating data mining tools 2. Business case for replacing CSS 3. Completed and issued RFP: purchase of an application and integration/implementation services 4. Completed software demonstration workshops 5. Vendor selected for: application, integration and implementation 6. Comprehensive Project Charter for the replacement of CSS 7. Preliminary project budget and plan for approval by Steering Committee

4. Resources Information

Estimated Resource Time Required for Scenario Analysis		
Which group(s) and/or individuals will be involved in this project?		
Role (*e.g. Developer, Analyst, Network Engineer)*	**Company, Department or Team**	**Hours needed**
Analyst / PM	Customer Service	360 (40 hrs X 9 Scenarios)
Analyst / PM	Operations	120 (40 hrs X 3 Scenarios)
Analyst / PM	Rates	40 (40 hrs X 1 Scenarios)
Analyst / PM	Meter Shop	40 (40 hrs X 1 Scenarios)
Analyst / PM	Collections	40 (40 hrs X 1 Scenarios)
Analyst / PM	Billing and Payments	40 (40 hrs X 1 Scenarios)
Analyst / PM	Finance/Accounting	40(40 hrs X 1 Scenarios)
Analyst / PM	Enterprise Technology	160 (16 hrs X 10 Scenarios)

5. Project Details

Proposed Start date:	2/1/2011	**Proposed end date:**	12/31/2011

Enter anticipated project implementation cost: (*with comments where appropriate***)**		
Cost of labor (existing staff**)**	$33,600	*840 hrs X 40 – Avista staff from various areas of the company*
Cost of labor (new staff or contract**)**	$20,000	*Architecture/Platform/Integration review*
Cost of Hardware	$0	*No hardware purchase within Phase 1*
Cost of Software	$0	*No software purchase within Phase 1*
Other Costs	$300,000	*External consultants and site visits;*
Total Cost:	$353,600	

Enter total post-implementation costs			
Estimated Cost (Maint.)	$0	**Over # of years:**	**Na**
Estimated Cost (Other)	$0	**Over # of years:**	**Na**

Major Known Risks *(including significant Assumptions)*

Avista resource availability
Other competing projects such as Smart Grid and Performance Excellence

Constraints (*List any conditions that may limit the project team's options with respect to resources, personnel, or schedule (e.g., predetermined budget or project end date, limit on number of staff that may be assigned to the project)).*

O&M funding in 2011

5. Sign-off

	Name	Signature	Date
VP / Controller	Christy Burmeister-Smith		
VP / CIO	Jim Kensok		
VP Operations	Don Kopczynski		
VP Regulatory	Kelly Norwood		
VP Finance	Jason Thackston		
VP Energy Solutions	Roger Woodworth		

6. Notes or Additional Information

Typical Scenarios Types
1) Search & Navigation
2) Customer History
3) New Premise Development
4) New Residential Service
5) Rate Definition & Management
6) Meter Management & MDM
7) Billing & Payments
8) Workflow: High Bill Complaint
9) Severance & Collections
10) Technology Requirements

Planning Timeline – Note: Updated timeline will be provided by the Consultant we partner with for the initial phase.

2011											
Typical Timeline Key Tasks	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Develop business and technology requirements											
Evaluate alternative commercial packages											
Conduct evaluation criteria workshops											
Business case for replacing CSS											
Complete and issued RFP: purchase of an application and integration/implementation services											
Complete software demonstration workshops											
Vendor selected for: application, integration and implementation											
Comprehensive Project Charter for the replacement of CSS											
Preliminary project budget and plan for approval by Steering Committee											

Attachment 4

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CIS Project Update

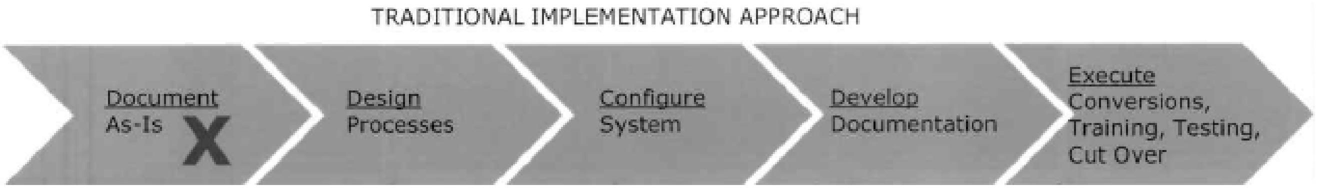
Executive Steering Committee

April 1, 2011

Why Replace CSS?

- Current support staff is tenured; limited resources in the market to support our custom legacy system
- System is 17 years old and is currently written in obsolete program languages (Smalltalk & COBOL)
- Legacy billing system can't accommodate new products, programs and services the utility will offer with Smart Grid
- Legacy billing system is highly customized. Hierarchy of payments is very costly to realign required commission rules and regulations. Contract billing does not exist.
- Lack of Customer segmentation, optional enrollment programs, limited ability to collect customer data and no customer relationship management.
- Legacy system is premise based which makes it difficult to follow the customer.
- Integration is limited and costly to our legacy system.

CIS System Replacement Journey



Change Management is Key
Approximately 3000 common functional and technical requirements
Approximately 200 business processes to document
Gap Analysis performed to define future state
Configuration and Integration
Training and documentation
Conversion and cut over

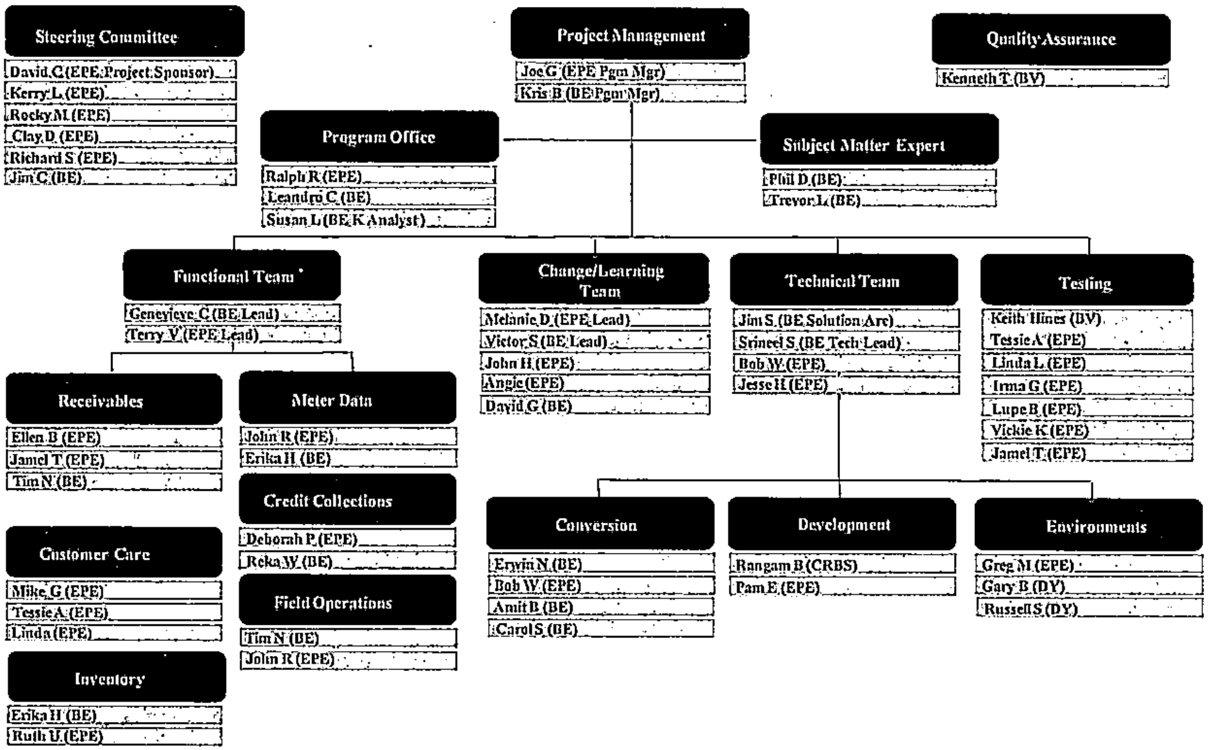
CIS Project Timeline

YEAR 1				YEAR 2				YEAR 3				YEAR 4				YEAR 5			
Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Plan			Select			Install						Stabilize							

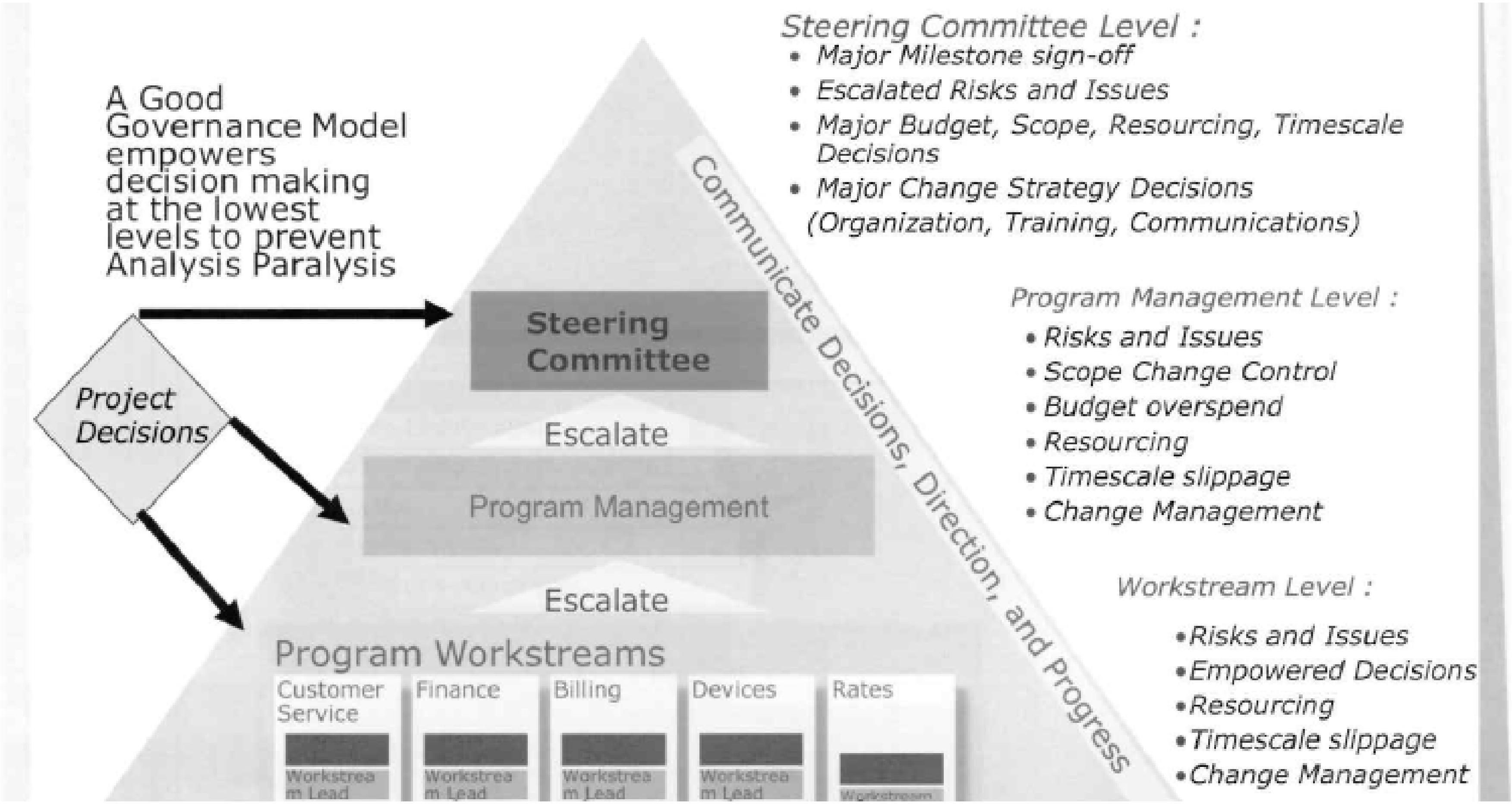
- CIS application plans are taking between 3 and 6 months to complete.
- CIS selections are taking between 7 and 9 months to complete.
- CIS installations are taking 16 to 24 months to complete.
- Once in production it is taking 6 to 12 months to stabilize the new CIS.

Project Staffing Critical to Success

- El Paso CIS Project Team
  One Service, Two States, Delayed Collection



Project Management



Successful Steps to Implementation

- Industry tier one software solution (Oracle or SAP) on standard technology platform
- Package enabled re-engineering of business processes
- Limited customizations (vanilla)
- Clear business vision with organizational buy-in from top down around people, scope, budget and timeline.
- Staffed with best and brightest resources
- Strong project management support
- Early communication around change management, training and strategy starting on day 1
- Phased approach: 1-Design & software selection; 2-System integration and configurations; 3-Quality Assurance, test, assess and launch
- Become risk adverse by limiting all competing priorities. (CSS lock down on 9/1/2011)

Progress to Date

- Charter Approved
- Five Industry leading consultants responded to RFI, scoring completed
- Interviewing two additional consultants
- Visit to El Paso Electric to discuss CIS implementation of Oracle by PWC
- Attended Chartwell Webinar Best Practices in CIS Implementation
- Janna Leaf and DJ Kinservik currently documenting 200 business processes
- PAR for 10 CSR's in process (awaiting approval)

Next Steps

- Hire Project Manager
- Approval to invite El Paso Director of Customer Care and CFO Executive Sponsor to share their experience with the Officer team.
- Interview Five Point and Black and Veetch Consulting
- Select and engage consultant for design and software selection
- Build proposed project org chart with approval to commit our best and brightest employees
- Proposed and approved 3 year capital budget plan for $40-$60M inclusive of CIS/WMS/AM, space allocation, technology, Avista FTE backfill and consultant support, attorney (internal and external for contract support)…
- Request commitment to move forward

El Paso CIS trip Summary

- Very strong executive support (previously lost $17.5 million and failed CIS project)
- 2 Dedicated El Paso PM's
- Customer communication around bill format was biggest challenge
- Training was company wide (many application and screen changes)
- Change Management from Day 1
- No parallel systems due to reconciliation complexity
- April to August – no customer collections. Wrote off $3.9M. Focused on getting the bills out first.
- SLA's and metrics not captured in one repository to date
- Aging report not tied to GL
- Minimal involvement from finance caused major account issues.
- Short resources overall
- Contract was not clear around data conversion

El Paso CIS trip Summary…cont.

- Technology risk for installation of CC&B was minimal except for ESB
- Net metering billing failed. Still not billing 94 customers
- 116,000 project hours (they estimated Avista will be 225,000 project hours)
- Business analyst can configure the system without programming assistance.
- TIBCO Enterprise Service Bus was key to their success around integration
- Stopped all other projects and focused on CIS
- When System Integration started implementation, 90% of IS staff was consumed on project
- No staff reduction as a result of the project. To Do's
- 15 months in phase one, 17 months in implementation.
- Brought in outsourced call center due to extensive training (14 days of training for each rep)

Attachment 5

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

March 11, 2011

Regarding: Avista's Request for Information RFI No. R-37173
Customer Service System Replacement Project

Avista Corporation ("Avista") is pleased to invite your company to respond to this Request for Information ("RFI") for selection of a vendor to aid in the development and implementation of the replacement of Avista's Customer Service System (the "Project"), specifically Phase One of the Project, as further outlined below.

Avista Corporation is an energy company involved in the production, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is the operating division that provides electric service to 357,000 customers and natural gas to 316,000 customers. Avista's service territory covers 30,000 square miles in eastern Washington, northern Idaho and parts of southern and eastern Oregon, with a population of 1.5 million. Avista's primary, non-regulated subsidiary is Advantage IQ. Avista's stock is traded under the ticker symbol "AVA." For more information about Avista, visit www.avistacorp.com.

This RFI is being sent to your company for the sole purpose of understanding your company's qualifications, knowledge and experience in providing the specified services. Based on the responses Avista receives to this RFI, Avista will compile a list of "pre-qualified" vendors from whom Avista may request a formal proposal (the "Short-Listed Vendors") or supplemental questions to this RFI for additional information. Short-Listed Vendors will be allowed to provide a proposal for any or all of the services described herein and in the subsequent Request for Proposal as part of Phase Two of the project.

Avista plans to replace its Customer Information System, also referred to as the Customer Service System ("CSS"). The current CSS legacy system has been in place for over 20 years and is highly customized. Avista is seeking to replace its legacy CSS to update technology, improve system performance and expand capabilities to prepare for future customer information needs.

Avista intends to replace its CSS system by engaging in the following three phase process:

1. Phase One - The Phase One vendor will help Avista develop the business requirements, process decisions, perform gap analysis, assist in the production of the Request for Proposal document and participate in selecting the system integration ("SI") vendor as part of the RFP process for Phase Two.

   The Phase One vendor will be required to provide the following:

   a) Industry analysis: compare Avista's CSS needs and the requirements to the industry.
   b) GAP analysis: identify the gap(s) between Avista's current system and the requirements for the new system.
   c) Alternative analysis: identify alternatives for achieving the requirements of the new system.

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d) Business analysis: define the cost, benefits, return on investment, risk and time frame for the project.

The Phase One vendor will also be required to consult on the installation plan that would identify the necessary steps for successful implementation of the new system. The installation plan may include, but not be limited to, the following:

a) Project overview: An introduction of the entire project, identifying the scope, objectives, purpose, needs assessment and alternative solutions.
b) Technology plan: Identify the hardware, software and environment, database management system, application software, network connectivity, and desktop environment, and any other technology related requirements.
c) Installation plan: Address the project and quality management, hardware and software setup and training, business development, product configuration and conversion, data perpetration and cleanup, system format development product modifications, interfaces, reporting, training, testing, go-live, post implementation, and sign-off.
d) Management plan: Detail the project timeline, organization, staffing, risk, contingency and procurement requirements. The marketing plan should identify all of the business change management and external stakeholder campaign philosophies.
e) Project approach and Business Plan: Identify the expectations for the planning, selection, implementation, and post-implementation phases of the project. Costs should be identified in the business plan, which would allocate and track the project costs and vendor disbursement schedules.

2. Phase Two – System Integration: Engage a vendor to perform the system integration identified in Phase One. Avista understands that a second vendor ***may*** need to be chosen to perform this function. In the case that the Phase One provider is unable to provide system integration support, it is intended that the Phase One services provider will assist with developing a separate Request for Proposal, if necessary.

3. Phase Three- Quality Assurance. This may be a third separate vendor or may be performed by the vendor selected to perform Phase One. The advantage of selecting the same vendor will be that the vendor will already be very familiar with the project and will be able to determine if the SI vendor met the requirements of the CSS system implementation and if all the business requirements were met as part of the project. However, choosing a separate third vendor would allow for a second set of eyes and expertise to review both Phase One and Phase Two work.

This Request for Information is intended to aid in the selection of the Phase One vendor for the services detailed above. Participating vendors should provide information specific to their expertise and participation in projects of the same magnitude for the Phase One Services as it relates to a total CSS system replacement and implementation. As part of this RFI, vendors are requested to provide, at a minimum, the following information in order for Avista to best determine each vendor's ability to provide the Phase One requirements of a CSS replacement project.

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Based on the information provided above, please provide as much information as possible regarding the following requested inquiries:

a. Please provide in-depth information about your product and service offerings regarding CSS systems,
b. Please describe the anticipated timeline to complete Phase One of the Project;
c. Please describe in detail your approach and project activities that would ensure a successful CSS replacement project: This could include, but is not limited to, a commercial off-the-shelf system, a practical implementation process; business process modifications typically needed, project management requirements, change management requirements, composition of the project team, proactive business process improvements, change controls, project planning and communication strategy(ies),
d. Please describe your company's understanding of the business process necessary to perform a full, successful CSS replacement; please provide your approach to this type of work;
e. Please describe in detail your company's "best practices" philosophy regarding CSS replacement projects; describe some of the "lessons learned" that would help Avista avoid some typical pitfalls of this kind of project and describe, in your company's experience, the key success factors for a successful Phase One portion of the Project.
f. Please provide two or more case study examples of your experience in providing the consulting services for CSS systems, preferably for utility companies.
g. Please describe your company's overall resource mix. Please also provide detail of the available experience level of your resources that would be available to Avista to successfully execute Phase One
h. Please advise whether your company would allow Avista the option to interview the specific individuals in your company that would comprise the Avista CSS Project team to accomplish the Phase One requirements if your company is chosen as the Phase One provider.
i. Please describe the kind of resource commitment your company would be willing to make if Avista requests specific resources.
j. Please provide current references, especially any utility companies that your company has provided CSS replacement services for in the past three (3) years;
k. Please describe the portion of your current business that Avista comprise if your company were selected to partner with Avista on the CSS Project; describe whether Avista's business would comprise more than 20% of your company's existing business.
l. Please detail whether your company will utilize subcontractors to perform any of the defined scope of work.
m. Please describe any additional value-added service offerings that could benefit Avista, such as management consulting services, access to technology partners, internal knowledge capital or SMEs, or other business relationships that you would bring to bear on Avista's CSS Project to ensure its success.
n. Please provide information regarding whether your, or your recommended vendor's CSS system, can align with its own or another Work Management System, on a forward looking basis for a possible future replacement of Avista's own Work Management System.

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The following factors will be essential in Avista's selection of a Phase One vendor: interpersonal relationships, vendor experience and level of independence, cost to perform the services and references for assurance. The chosen vendor is critical to Avista for developing the business requirements, process decision, RFP production and participation in the selection of the SI vendor. Ultimately, this will make the CSS replacement project as a whole, successful, efficient, economically sound and meet both Avista's and its customers' expectations.

All information shared with Avista under this RFI, the RFI process and the ultimate vendor selection will be confidential.

Once a vendor is selected, a contract for services for the Phase One services will be negotiated between the Parties prior to work commencing.

Please note that Avista is interested in proceeding immediately on the Phase One portion of the CSS Project so time is of the essence.

You may send an electronic copy of your response to Stacey Levin, Senior Contract Manager, at slevin@avistacorp.com. All RFI responses are due on or before 5:00 p.m. Pacific Time on March 25, 2011. All responses should refer to Avista's RFI No: R-37173.

Please direct any questions you may have regarding this RFI to Pat Dever at pat.dever@avistacorp.com. All inquiries should refer to Avista's RFI No: R-37173.

Sincerely,

Stacey M. Levin
Senior Contract Manager
Avista Corporation

Cc: Avista Contract File No. R-37173

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Attachment 6

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Vendor Information for
CSS Replacement RFI: Phase One
RFI No. R-37173
Note: Highlighted vendors responded

1. Vertex, Inc.
   james.will@vertexna.com

2. Black and Veatch Corporation
   Renee Koch
   KochR@bv.com

3. Five Point Partners, LLC
   Rich Charles, Sales Manager
   (214) 530-5989
   Richard.Charles@fivepoint.net
   Address:
   2526 Mt. Vernon Road
   Suite B348
   Atlanta, Georgia 30338
   info@fivepoint.net
   (888) 830-4959 Toll Free

4. PricewaterhouseCoopers, LLP (formerly BearingPoint)
   james.m.curtin@us.pwc.com

5. Bridge Strategy Group, LLC
   Robert Zabors
   rzabors@bridgestrategy.com
   Address:
   Bridge Strategy Group
   One North Franklin Street
   Suite 2100
   Chicago, IL 60606
   Phone 312-357-6740
   Fax 312-357-6750

6. Computer Sciences Corporation (CSC, formerly Bass & Co.)
   Theresa Skorupa
   973-243-7360
   tskorupa@csc.com
   Address:
   3170 Fairview Park Drive
   Falls Church, VA 22042 USA
   1-703-876-1000

7. Heights Consulting (partnered with Jericho Consulting)

Attachment 7

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CONFIDENTIAL

Scoring results from assessment of vendor proposals, per Attachment 5 & 6

Pages 1 through 2

Attachment 8

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Aldyl A Natural Gas Pipe Replacement and Project Compass

Avista Corporation

RFP R-37440

Avista is seeking Proposals for qualified information system solutions consisting of the complete functionality of a Customer Information System (CIS) and an Enterprise Asset Management ("EAM") (also known as a Work Management System ("WMS"). These functional areas and specific requirements are explained more fully later in this RFP. Avista is seeking a fixed priced Proposal for conversion, testing, training, implementation, post-implementation, software, and hardware (collectively, the "Enterprise Solution").

Avista has elected to issue this single RFP rather than separate RFPs for each functional system. However, Solution Provider(s) may respond to one, several, or all of the requested functional systems based upon Solution Provider(s) area of expertise and/or desire to form partnerships with other providers. In the final analysis, Avista reserves the right to select proposed solution components that are the best fit for its needs.

The new Enterprise Solution (also referred to as the CIS and EAM Solution) must be professionally installed, must be integrated or highly interfaced and will provide enhanced functionality and the ability to interface with other third party applications.

OPTIONS

This RFP will consider the following solution alternatives:

1. A complete Enterprise Solution consisting of CIS and EAM functionality. These Proposals may be for fully integrated solutions, or they may be for best of breed solutions that are highly interfaced (a "Partnered Solution").
2. A solution consisting only of CIS. However, the Solution Provider must demonstrate successful integration with EAM solutions at utilities similar to Avista.
3. A solution consisting only of EAM. However, the Solution Provider must demonstrate successful integration with CIS solutions at utilities similar to Avista.

SUMMARY OF RFP SCOPE OF WORK

Several key system and service related components have been identified to achieve Avista's stated business objectives. The total effort outlined in the RFP calls for a complete Enterprise Solution. The Enterprise Solution consists of the following components:

- **Customer Information System (CIS)**

  The new CIS solution will include all software and services required to implement and support the stated interfaces and traditional CIS functions such as customer service, account management, credit and collections, service orders, meter inventory, usage, billing, service address management, portfolio management, rates, and financial based activities. The Enterprise Solution will include utility specific Customer Relationship Management (CRM) functionality.

- **Enterprise Asset Management (EAM)**

  The new EAM will include all software and services required to implement and support the stated interfaces and traditional work management and asset management functions such as work initiation, work planning, work approval, work scheduling, work execution, work closing, and work reporting. Avista seeks a system that will accommodate typical utility generation, transmission and distribution operations. Avista is not seeking inventory and procurement functions, only the integration to those functions in Avista's Oracle eBusiness financial suite. The new EAM will also include asset maintenance and management functionality including analytics and metrics.

- **Mobile Workforce Management (MWM) System**

  Avista's current CSS interfaces to ABB-Ventyx Service Suite version 8.1 mobile data system. With the new CIS solution, Avista is considering a new, fully integrated MWM system for all orders generated out of CIS. A later phase may include integration with the new EAM for the long-cycle work that is currently generated out of WMS. As an alternative, if the proposed solution does not include a **fully integrated MWM solution**, the Solution Provider must factor into the solution the time and expenses to fully interface ABB-Ventyx Service Suite with the proposed CIS solution.

- **Data Access Solution**

  Avista is seeking access via a standard set of tools to the CIS and EAM application data for reporting and analysis. The data access solution will include all hardware specifications, software and services required to implement and support application query and reporting within both the CIS and EAM. However, Avista is not seeking an Enterprise Information Management (EIM) or to replace our current Cognos Enterprise Business Intelligence (BI) solution.

- **Full Integration**

  The new CIS and EAM will contain full integration between the various modules in each of the solutions. The new systems will also facilitate efficient and effective integration to other Avista systems. There must be a clear approach to master data management supporting both internal integrations as well as external system integrations through industry standard methods.

- **Partnered Solution Approach**

  If this is a Partnered Solution, Avista requires that one of the Solution Providers assume responsibility for the complete solution implementation as the Prime Vendor, to include all necessary interfaces and be responsible for the provision of the functionality requested by Avista in this RFP. Avista requires a Prime Vendor approach for these Partnered Solutions to manage, coordinate implementation and be responsible for all subcontractors and third-party software related to their proposed Partnered Solution.

- **Implement Improved Business Processes**

  Avista expects the Solution Provider(s) to provide leadership during product configuration to implement common / best practices in order to meet the application's functionality. Avista will rely upon product configuration rather than product modifications and will consider modifying its business processes to fit the technology workflow.

MINIMUM REQUIREMENTS

Avista expects the Proposed Solution(s) meet the following minimum requirements and that each of these requirements be included in and clearly addressed as part of the Proposal. In reviewing these minimum requirements, Solution Provider(s) should consider each item's relevance to the specific solution or service being proposed.

Proposed software minimum requirements:

1. The Proposed Solution is successfully in operation at a minimum of 10 utilities in North America, three of which serve a minimum of 500,000 gas and electric customers.
2. The Proposed Solution is currently in production on a similar platform as that being proposed for Avista.
3. The Proposed Solution has been proven to scale to over one million customer accounts.
4. The Proposed Solution will promote implementation of a functionally rich base product with minimal modifications. Avista will not accept custom development Proposals or those that rely on extensive levels of customization. In addition, Solution Provider must be capable of providing ongoing maintenance support and scheduled product releases as demonstrated through a well-defined, robust product road map.
5. The Proposed Solution must accommodate a multi-company or multi-state environment with varying tariffs, rules and regulations (at least three states and three utility commissions).
6. The Proposed Solution must include licensed packaged products capable of being run either within an in-house data center or in a hosted data center on Avista's behalf. Avista will not consider a Software as a Service (SaaS) solution at this time.

Solution Integrator minimum requirements:

7. The SI must be a well-established professional organization that offers the implementation / integration of hardware, software and services for Proposed Solution. The SI must have been in business for a minimum of three years. The SI shall place only experienced professionals on the Proposed Solution. The project manager, technical lead, and functional lead must have a minimum of three referenceable implementations and at least five years experience of the Proposed Solution. Other level professionals must have a minimum of two years of experience with the Proposed Solution.
8. The SI must be a financially healthy institution capable of conducting business during the entire Proposed Solution implementation period and the associated post go-live support period as measured by financial statements, D&B report, etc. SI shall attach three years of audited financial records, D&B reports, etc., and any interim statements.
9. The SI must not be involved in any litigation that may potentially impact the SI's ability to support Proposed Solution and any required support. The SI must disclose any and all existing and pending litigation in the RFP response.

Questions regarding this procurement and RFP are due by end of business Pacific time, Thursday, September 22, 2011.

The will be a pre-proposal phone conference on Tuesday, September 27.

Proposals are due by 3:00 p.m. Pacific time, Friday, October 21 2011.

If you would like to receive this RFP, you will be required to complete, sign and return Avista's Non-Disclosure Agreement and Five Point Partner's Terms of Use Agreement, and register the individuals who will access **STAR**. **STAR** is the acronym for Five Point Partner's "**Selection Tool for Assessment and Requirements.**" This online tool replaces functions and features checklists of software product functionality. This tool will be used by the Solution Provider(s) to access Avista's requirements for the new Enterprise Solution. Those documents must be fully executed and sent to Gary Weseloh at gary.weseloh@fivepoint.net before the RFP documents will be released.

Attachment 9

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Avista RFP Distribution List (September 12, 2011)

CIS Vendors:

CC&B (Oracle) Adam Stafford adam.stafford@oracle.com
and Michael Fryke michael.fryke@oracle.com
and Joe Caprice joe.caprice@oracle.com
and David Bickerstaff david.bickerstaff@oracle..com 903-340-9502
CRB - SAP (Roger Egle) roger.egle@sap.com 541-221-8142
Vertex - Dan Sullivan dan.sullivan@vertexgroup.com 214-576-1000

EAM Vendors:

Maximo (IBM) – Bill Boone waboone@us.ibm.com
and Chris Norton chris.norton@us.ibm.com
and Patrick Baxter pbaxter@us.ibm.com
and Jeff Burch (sycomp) jburch@sycomp.com 650-312-8174
WAM (Oracle) - Adam Stafford adam.stafford@oracle.com
and Michael Fryke michael.fryke@oracle.com
eBusiness Suite (Oracle) - Adam Stafford adam.stafford@oracle.com
and Michael Fryke michael.fryke@oracle.com
SAP - Roger Egle roger.egle@sap.com 541-221-8142
Logica - Shannon Nafaa shannon.nafaa@logica.com 713-954-7003
and Kurt Ergene kurt.ergene@logica.com 760-591-4810
~~Invensys – Plano Headquarters office - 469 365 6400~~ (they are not interested in this RFP)
Cascade –Neil npm@cascade-assets.com 888.222.8399
Infor – Alpharetta GA Headquarters office – 800-260-2640 (no answer – I'll keep trying)
Passport (Ventyx) - Leo Hagood leo.hagood@abb.ventyx.com 404-630-4846
Tabware - Hope Brooks-Moore hope.brooks@assetpoint.com 864-679-3415

CRM Vendors:

ISM (Sage SalesLogix) - Scott Smallbeck scott@goism.com 503-496-5374

Solution Integrators:

Ep2M - John Schulte john.schulte@ep2m.com 402-968-6634
HCL - Mark Graham mark.graham@hcl.com 925-381-7742
and John Lugviel jlugviel@comcast.net 509-443-0158
and Andrew Jornod Andrew.jornod@hcl.com 214-578-7969
Waggware - Paul Buster paulb@waggware.com 281-436-7280 x 240
Accenture - Ron Aberman Ronald.aberman@accenture.com 355-401-0304
and Trey Thornton trey.thornton@accenture.com 818-795-6608
IBM – Tony Johnson Anthony.johnson@us.ibm.com 205-482-7311
and Jacob Miller Jacmille@us.ibm.com 206-587-6775
PwC – Steve Obosnenko steven.obosnenko@us.pwc.com 610-357-7550
and James Mergenthaler james.d.mergenthaler@us.pwc.com 312-298-5826
Deloitte – Tom Turco tturco@deloitte.com 678-521-7972
and Ian Wright iwright@deloitte.com 215-430-6217
and Jason Stevens jasonstevens@deloitte.com
and Gabriel Tovar gtovar@deloitte.com

Sparta – Shelaindra Bhardwaj sbhardwaj@spartaconsulting.com 888-985-0301 x 246
and Chandra Joshi cjoshi@spartaconsulting.com 888-651-2952 x 147
Cap Gemini – Ian Roy ian.roy@capgemini.com 972-793-4400
Infosys – David Shin david_shin@infosys.com 954-452-7311
Wipro – Walt Little walt.little@wipro.com 941-735-6293
ProMark Solutions – Gabrielle Porath gporath@promarksolutions.net 702-622-7863

Attachment 10

BEFORE THE
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LARRY D. LA BOLLE
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Aldyl A Natural Gas Pipe Replacement and Project Compass

AVISTA

PROJECT COMPASS

GUIDEBOOK

Project Compass Guidebook

2012

Client Manager: Michael Mudge

Revisions:

Version	Date	By	Approved
Version 1	1/27/2012	Peggy Blowers, Jody Morehouse, and Michael Mudge	

Preliminary Draft Confidential

Please note that the information contained herein is preliminary and for discussion purposes only. It does not necessarily represent the views of Company management (and may, in some cases, represent only the views of independent consultants or advisors). Accordingly, any preliminary estimates, costs or benefits, as well as the characterizations of such, are subject to change and will be revised as, and to the extent, the project proceeds.

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Procurement Phase

Procurement Phase

This section of the guidebook is specific to the Procurement Phase of Project Compass.

Procurement: Objective

Avista's homegrown, customized customer information system (CIS) has served our company and our customers well for over 20 years. Integrating commercial, off-the-shelf software and other internally developed systems into the CIS over time has fortified the technology foundation that helped Avista receive national awards and consistently high customer-service ratings. But at the end of the day, Avista's CIS has design limitations to accommodate future products, programs and services; is supported by an aging workforce, and any enhancements increase the complexity of the system. Taking Avista into an energy future with technology as its foundation requires a flexible CIS platform that can provide the choices that matter most to our customers.

When Avista's CIS platform was developed 20 years ago, there were no smart phones or iPads. Home computers were uncommon and customers did not expect to be involved in energy choices. While our current CIS provides good functionality and is user friendly, it is important that Avista's technology continues to evolve, and is able to deliver the type of service options that we believe customers will seek.

Avista's investments in developing a smarter grid will enable a different, more interactive relationship with our customers. To achieve these objectives, Avista's CIS may include the ability to accommodate not only Smart Grid technology, but also may incorporate:

- Automated meter information
- Energy efficiency programs
- Real-time billing
- On-bill financing
- Automated notifications based on customer preferences
- Customer relationship management capabilities
- Multi-channel, self-service options.

In addition, the new CIS needs the flexibility to accommodate regulatory changes.

Refurbishing or replacing Avista's CIS is a significant decision that will impact all aspects of the company's operations. Linking into the CIS are many current company systems. These include

Procurement: Objectives Continued

outsourced bill presentment, outage management, work and asset management, automated phone system, construction design, enterprise business intelligence, supply chain and financial systems. Also linking into CIS are electric and gas meter applications, and the avistautilties.com website for managing customer self-service transactions.

Replacing the customized CIS with an off-the-shelf application means a commitment to adjust Avista's business processes and procedures to align with the software. Managing the change process will be a key element of the project plan. Avista is committed to moving forward with replacing its legacy customer service system with an off-the-shelf application. This will provide the company with industry standard software and a solution that will keep pace with Avista's evolving energy business. It will also eliminate the challenges of maintaining a customized system.

Procurement: Scope

CSS – (Customer Service System)

CSS is Avista's home grown customer information system was implemented in August 1994 and supports all of the traditional utility business functions such as meter reading, billing, payment processing, credit, collections, field requests and service work orders.

The Customer Service System (CSS) is an internally-developed system that was implemented in 1994 following a three-year development effort – it replaced a prior internally-developed CIS system that ran on the mainframe platform. The new system was developed utilizing then newer technology (relation databases, CASE tool, SmallTalk, etc.). An enterprise-wide information modeling project preceded this project, so the system was developed utilizing concepts such as single-source data, subject-area databases, etc. – it was very data-driven.

The system handles all aspects of customer / customer account processing including billing, collections, payments and deposits, metering and usage.

- CSS is currently supported by Avista's in-house HP Workplace Support Team.
- CSS is the single source for customer-related data which is widely used throughout Avista. Much of the data is exported to an Oracle database (WRKPRD) where it is available for ad hoc reporting. A Customer DataMart also resides in WRKPRD, providing enhanced reporting capabilities through Cognos.
- The batch billing processing window is typically from 8:10pm to 1:00am Monday – Friday.

Procurement: Scope Continued

WMS – (Work Management System)

WMS is Avista's home grown work management system that is tightly integrated with CSS. WMS is used to create constructions jobs. The materials are ordered though WMS which is interfaced with Oracle ERP. The integration is one way; the service technicians can order through WMS but are unable to track the order. Avista staff can also assign jobs to a crew but this too happens through use of another program which is being revised as part of Avista's Performance Excellence program. Avista also orders locates and right away permits using WMS. Avista has been unsuccessful to do the same in Construction Design Application (CDA) because the various Municipalities we serve are unwilling to standardize and use email as a form of communication for permits.

EGMA – (Electric and Gas Meter Application)

EGMA supports electric and gas meter inventory, meter tracking and meter testing. EGMA is tightly integrated with CSS.

Mobile, METS, and Gas Compliance Applications

The replacement of our CIS/WMS (WorkPlace) system will greatly impact our Mobile, METS, and Gas Compliance systems. As these systems are heavily integrated with the Workplace, and as the new CIS/WMS will likely cause many information and process changes; these systems will need to be closely reviewed for scope, change, and integration.

(See Appendix A to view Avista's Current Business System Model.)

Procurement: Roles and Responsibilities

Executive Steering Committee

- Commit to being an advocate and champion of the CIS project.
- Approves initial and changes to project scope, budget and timeline.
- Attend and actively participates in Steering Committee meetings, critiquing the ability to perform on scope, budget and timeline.

Procurement: Roles and Responsibilities Continued

- Critique project scope, budget and timeline based on long-term vision and corporate compliance.
- Question to understand high level decisions brought to the Steering Committee for resolution. Support decisions or reject with options or opportunities to resolve.
- Support the communication needed regarding change as a result of the project, both formally and informally, sharing both consequences and impacts to company and project.
- Commit to Change Management as a means of positive impact to all areas of company operations.
- Approves all invoices, CPRs, and charges over $99,999. Approve all additions to compliment.
- Approve and support resources from all key areas of the company. Intervene as requested to assure attendance and commitment.
- Allow project sponsors first line of opportunity to manage and communicate with solution providers, employees and interveners.

Executive Officer Sponsor

- Defines the strategic goals, liaison between steering committee, the remaining Executive Team and the Board of Directors
- Ensure corporate-wide acknowledgement, participation and buy-in
- Provide input and advice on Avista operations from a corporate and management-level as they affect the project
- Resolves inter-departmental issues that cannot be resolved at a project sponsor level
- Attends and actively participates in Steering Committee meetings

Executive Project Sponsors

- Provide oversight, leadership and vision for the CSS/WMS replacement project
- Responsible for the direction and planning of the CIS/WMS selection, including facilitating resource needs, resolving issues and executive communication
- Create and communicate CSS/WMS replacement project high-level vision
- Manage upward communication to the Steering Committee and other business leadership groups
- Review progress and resolve issues elevated by the project
- Oversee management of CSS/WMS risks and issues
- Act as escalation point for significant vendor issues; maintain working relationship with vendor executives
- Review and act upon budget changes and/or additions
- Ensure project objectives and goals support and link with the general business goals and mission
- Approve major project decisions
- Provide oversight and mentor the team
- Responsible for project outcome
- Responsible for approving, prioritizing, or deferring significant issues
- Attends and actively participates in Steering Committee meetings

Procurement: Roles and Responsibilities Continued

Compass Directors Panel

- Key Stakeholders for the CSS/WMS project as a whole
- Responsible for assuring the new systems will meet their department and division needs
- Assume responsibility for their areas participation and ultimate project success
- First-line resource in issue escalation from the project sponsors
- Be in direct communication with the project team members that report to them
- Attend CSS activities as requested
- Create CSS/WMS vision for their area
- Work with project team resources to ensure they have the line of business vision for CSS/WMS in mind during the project process
- Escalate and communicate issues with both the core project team resources and their management for resolution
- Work with Avista Project Manager and Five Point Project Manager on requested deliverables and/or project activities
- Attend and participate in Director Team meetings

Five Point Partners

- The Five Point Project Manager provides direction on the CSS/WMS Replacement Project (Project Compass) methodology
- Provide industry expertise and guidance in working with the CIS/CRM and EAM/WAM vendors and SI's
- Accountable to the Project Manager and Executive Sponsors for regular updates on progress and status
- Provide proposed Project Compass schedule, including critical path milestones and dependencies with other projects
- Continuously forecast and anticipate changes in scope, resources, timelines, budget, etc.
- Participate in Executive Steering Committee meetings

Avista Client Manager

- Provide Project Management and leadership to the Avista Project Compass Team
- Accountable to Project Sponsors for providing information for regular progress & status updates
- Create a collaborative relationship between all departments
- Update and manage project schedule, including the Avista team activities, critical path milestones and dependencies with other projects
- Identify, track, resolve and/or escalate project issues
- Manage the change control process for any"' changes to project scope, timeline or budget
- Manage key Stakeholder expectations for the project
- Provide invoice validation for all vendor payments
- Work with Project Sponsors and other management to secure required Project Team members
- Ensure work products meet quality standards
- Identify, oversee and resolve issues and risks related to cross-project dependencies

Procurement: Roles and Responsibilities Continued

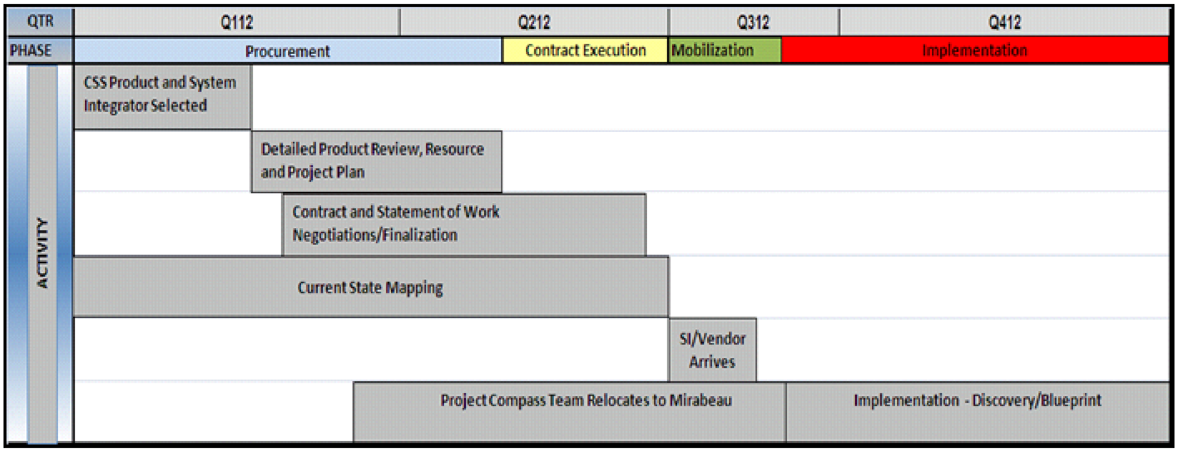
- Primary contact between Avista, CSS/WMS vendor(s), Quality Assurance consultant, and System Integration (SI)
- Collaborate with SI to develop and maintain detailed and accurate comprehensive project plan
- Provide a weekly project status report to the Project Sponsors
- Participate in project status meetings
- Facilitate regular meetings with the Directors Team

Project Compass Procurement Team / Subject Matter Experts (SMEs)

- Provide information on an as-needed basis
- Provide expertise in their particular subject to inform the CSS/WMS selection process
- Provide input on the recommendations for the project
- Provide requested information to Avista Project Manager and/or Five Point Project Manager
- Attend project meetings and activities as requested by Avista Project Manager and/or Five Point Project Manager
- Provide guidance on the CSS/WMS business requirements, gaps and issues
- Identify issues and risks for area of responsibility or outside that area if necessary
- Update the Avista Project Manager on any issues
- Serve as key SME to project meetings, RFP and system reviews
- Represent your department needs and keep your department and management informed
- Look for opportunities to optimize processes and procedures by leveraging the new system features and functionality
- Be willing and open to change, agree to disagree and support decisions made with a positive attitude
- Meet project deliverables and timeline on assigned tasks and issues
- Provide expertise regarding functionality, business processes and technology

Procurement: Timeline

New Customer Service System is key to Agile Technology Platform



Project Compass

- CSS Product and System Integrator Proposal Feb 7
- Contract finalized by May 30
- Current State Mapping complete by June 30
- SI and Vendor "mobilize" at Avista in June
- Balance of Project Compass Team to begin move to Mirabeau in July
- Implementation begins in earnest in July, focusing on due diligence to define future state processes

Procurement: Organization and Staffing

Executive Steering Committee	
Don Kopczynski (chair)	Jim Kensok
Jason Thackston	Dennis Vermillion
Roger Woodworth	Dick Storro

Executive Sponsors	
Pat Dever	Vicki Weber

Procurement Consultants – Five Point	
Gary Weseloh	Greg Galluzzi
Craig Mills	Brent Dreher

Avista Client Manager	
Michael Mudge	

Procurement: Organization and Staffing Continued

Project Compass Staff	
Pat Dever	Vicki Weber
Mike Mudge	Janna Leaf
DJ Kinservik	Renee Webb
Peggy Blowers	Jody Morehouse
Lauren Turner	Gary Weseloh

Project Compass Procurement Team	
Vicki Weber	Pat Dever
Mike Mudge	Janna Leaf
DJ Kinservik	Renee Webb
Peggy Blowers	Jody Morehouse
Lauren Turner	Gary Weseloh
Bob Weisbeck	Lamont Miles
Tami Judge	Rodney Picket
Amber Gifford	Mollie Weis
Maureen Olson	Robert Dodd
Tom Heavey	Cam Mallon
Greg Paulson	Ken Humphries
Kelly Conley	Teresa Damon
Catherine Mueller	Bill Ramshaw
Frank Johnson	Jackie Foss
Judy Olson	Karen Doran
Kevin Farrington	Mark Michaelis
Mike Littrel	Rachelle Humphrey
Ron Simmons	Laurie Heagle

CIS Evaluation Team	
Vicki Weber	Pat Dever
Jody Morehouse	Teresa Damon
Mike Mudge	Lamont Miles
DJ Kinservik	Greg Paulson
Janna Leaf	Jackie Foss
Renee Webb	Ken Humphries
Gary Weseloh	Tami Judge
Peggy Blowers	Karen Doran
Maureen Olson	Kelly Conley
Robert Dodd	Rachelle Humphrey
Mollie Weis	

Procurement: Organization and Staffing Continued

Mobile Workforce Evaluation Team	
Vicki Weber	Pat Dever
Jody Morehouse	Jackie Foss
Mike Mudge	Mike Littrel
DJ Kinservik	Frank Johnson
Janna Leaf	Ron Simmons
Renee Webb	Robert Dodd
Gary Weseloh	Kevin Farrington
Peggy Blowers	Tom Heavey

Technology Evaluation Team	
Vicki Weber	Pat Dever
Peggy Blowers	Tom Heavey
Mike Mudge	Cam Mallon
DJ Kinservik	Bill Ramshaw
Janna Leaf	Mollie Weis
Renee Webb	Maureen Olson
Gary Weseloh	Robert Dodd
Jody Morehouse	Kevin Farrington
Ron Simmons	Mark Michaelis

WMS Asset Evaluation Team	
Vicki Weber	Pat Dever
Mike Mudge	Bob Weisbeck
Jody Morehouse	Lamont Miles
DJ Kinservik	Teresa Damon
Janna Leaf	Catherine Mueller
Renee Webb	Judy Olson
Gary Weseloh	Amber Gifford
Peggy Blowers	Rodney Pickett

Final Evaluation Team	
Vicki Weber	Pat Dever
Mike Mudge	Bob Weisbeck
Peggy Blowers	Rodney Pickett
DJ Kinservik	Tom Heavey
Janna Leaf	Jody Morehouse
Renee Webb	Tami Judge
Gary Weseloh	Lamont Miles

Procurement: Organization and Staffing Continued

Contract Negotiation Team	
Greg Galluzzi	Gary Weseloh
Pat Dever	Vicki Weber
Stacey Levin	Patty Wood
Louisa Barash	

Procurement: Schedule

Project Compass Procurement Calendar

Project Compass Procurement Calendar

Monday 1/23	**Tuesday 1/24**	**Wednesday 1/25**	**Thursday 1/26**	**Friday 1/27**
Service Order Mgmt WebEx	IBM/Maximo Prod. Demonstration	IBM/Maximo Prod. Demonstration	Ventyx 9.1 Demo	
CR 130	Auditorium	Auditorium	Auditorium	
1:30pm - 3:00pm	8:00am - 5:00pm	8:30am - 4:30pm	9:00am - 4:00pm	
CIS Evaluation Team/Open	WMS Asset Evaluation Team/Open	WMS Asset Evaluation/Open	MWM Evaluation Team/Open	
Follow-Up evaluation of SAP Service Order Mgmt capabilities	Refer to Demo Calendar	Refer to Demo Calendar	Refer to Demo Calendar	
	IBM Technology Breakout Session			
	CR 130			
	9:00am - 5:00pm			
	Technology Evaluation Team			
	Technology Evaluation of Maximo			
Monday 1/30	**Tuesday 1/31**	**Wednesday 2/1**	**Thursday 2/2**	**Friday 2/3**
CIS Evaluation	WMS/Asset Evaluation	Final Recommendation Workshop	Working Session	Steering Committee Roundtable
Mirabeau CR 701	Mirabeau CR 701	Mirabeau CR 701	Mirabeau CR 702	
8:00am - 2:00pm	8:00am - 12:00pm	8:00am - 2:00pm	8:00am - 5:00pm	
CIS Evaluation Team	WMS Asset Evaluation Team	Final Evaluation Team	Pat, Vicki, Gary, others as needed	
Opening Statement / Round Table / Score Gathering / Concluding Discussion	Opening Statement / Round Table / Score Gathering / Concluding Discussion	Review the data and conclusions of each of the previous eval. sessions, drive to Final Recommendation	Prepare Final Recommendation for Steering Committee	
Technology Evaluation	Mobile Workforce Evaluation			
Mirabeau CR 701	Mirabeau CR 701			
2:30pm - 4:30pm	1:00pm - 5:00pm			
Technology Evaluation Team	Mobile Workforce Eval. Team			
Opening Statement / Round Table / Score Gathering / Concluding Discussion	Opening Statement / Round Table / Score Gathering / Concluding Discussion			
Monday 2/6	**Tuesday 2/7**	**Wednesdsay 2/8**	**Thursday 2/9**	**Friday 2/10**
	Steering Committee			Notification to the Selected SI
	Executive Sponsers			Procurement Partners
	Deliver Final Recommendation			Deliver selection to SI
Monday 2/13	**Tuesday 2/14**	**Wednedsay 2/15**	**Thursday 2/16**	**Friday 2/17**
SI is mobilizing to prepare for the demo of 3500 requirements				
Avista - Additional Reference Checks and Possible Site Visits				
Project Staff/SME's				
Monday 2/20	**Tuesday 2/21**	**Wednesdsay 2/22**	**Thursday 2/23**	**Friday 2/24**
SI is mobilizing to prepare for the demo of 3500 requirements				
Avista - Additional Reference Checks and Possible Site Visits				
Project Staff/SME's				
Monday 2/27	**Tuesday 2/28**	**Wednesdsay 2/29**	**Thursday 3/1**	**Friday 3/2**
Detailed Product Review - CIS (2292 requirements)				
Auitorium				
8:00am - 5:00pm every day				
CIS Evaluation Team/SME's				
Ensure Product meets requirements				
Monday 3/5	**Tuesday 3/6**	**Wednesdsay 3/7**	**Thursday 3/8**	**Friday 3/9**
Detailed Prod Review Cont. CIS	Detailed Prod Review MWM	Detailed Prod Review EAM		Overflow
Auditorium	Auditorium	Auditorium	Auditorium	Auditorium
8:00am - 5:00pm	8:00am - 5:00pm	8:00am - 5:00pm	8:00am - 5:00pm	8:00am - 5:00pm
CIS Evaluation Team/SME's	MWM Evaluation Team/SME's	WMS/Asset Evaluation Team/SME's	WMS/Asset Evaluation Team/SME's	Pull in as needed
Ensure Prod. Meets Reqmts.	Ensure Prod. Meets Reqmts.	Ensure Prod. Meets Reqmts.	Ensure Prod. Meets Reqmts.	Ensure Prod. Meets Reqmts.
Monday 3/12	**Tuesday 3/13**	**Wednesday 3/14**	**Thursday 3/15**	**Friday 3/16**
SI Develops their Best and Final Offer and their Statement of Work				
Procurement Partners - Five Point Red Lines Vendor and Standart Contracts and Assists SI with SOW				
Project Staff Compiles additional information needed to start project				
Monday 3/19	**Tuesday 3/20**	**Wednesdsay 3/21**	**Thursday 3/22**	**Friday 3/23**
SI Develops their Best and Final Offer and their Statement of Work				
Procurement Partners - Five Point reviews first draft of SOW				
Contract Negotiation Team red-lines contracts and returns first iteration back to the SI and Vendors				
Monday 3/26	**Tuesday 3/27**	**Wednesdsay 3/28**	**Thursday 3/29**	**Friday 3/30**
SI and Vendors revise contracts based on Avista's first iteration				
Procurement Partners - Five Point and Project Staff review SI's SOW and develops the overall project plan, resource plan, project budget				
Contract Negotiation Team reviews BAFO				
Monday 4/2	**Tuesday 4/3**	**Wednesday 4/4**	**Thursday 4/5**	**Friday 4/6**
SI Reviews SOW changes from Avista and Five Point, and issues next version				
Contract Negotiation Team prepares for on site contract and SOW negotiations				
Monday 4/9	**Tuesday 4/10**	**Wednesday 4/11**	**Thursday 4/12**	**Friday 4/13**
SI and Contract Negotiation Team - on site contract and SOW negotiations				
Monday 4/16	**Tuesday 4/17**	**Wednesday 4/18**	**Thursday 4/19**	**Friday 4/20**
SI and Contract Negotiation Team - Independent Caucusing on outstanding contract issues				
Monday 4/23	**Tuesday 4/24**	**Wednesday 4/25**	**Thursday 4/26**	**Friday 4/27**
Procurement Partner - Five Point finalizes Contract Package and assits with preparation for contract approval presentations				Contracts Approved

Procurement: Resources

Procurement Resource Usage Matrix

	23-Jan	24-Jan	25-Jan	26-Jan	27-Jan	30-Jan	31-Jan	1-Feb	2-Feb	3-Feb	6-Feb	7-Feb	8-Feb	9-Feb	10-Feb	13-Feb	14-Feb	15-Feb	16-Feb	17-Feb	20-Feb	21-Feb	22-Feb	23-Feb	24-Feb	27-Feb	28-Feb	29-Feb	1-Mar	2-Mar	5-Mar	6-Mar	7-Mar	8-Mar
Vicki Weber	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Pat Dever	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Amber Gifford		X	X				X																										X	X
Bill Ramshaw		X			X	X																												
Bob Weisbeck		X	X				X	X																									X	X
Cam Mallon		X			X	X																												
Catherine Mueller		X	X				X																										X	X
DJ Kinservik	X	X	X	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Frank Johnson				X			X																									X		
Gary Weseloh	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Greg Paulson	X				X	X																				X	X	X	X	X	X			
Jackie Foss	X			X	X	X	X																			X	X	X	X	X	X	X		
Janna Leaf	X	X	X	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Jody Morehouse	X	X	X		X	X	X	X			X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X
Judy Olson		X	X				X																										X	X
Karen Doran	X				X	X																				X	X	X	X	X	X			
Kelly Conley	X				X	X																				X	X	X	X	X	X			
Ken Humphries	X				X	X																				X	X	X	X	X	X			
Kevin Farrington		X		X	X	X	X																									X		
Lamont Miles	X	X	X		X	X	X	X																		X	X	X	X	X	X		X	X
Lauren Turner											X	X	X	X	X	X	X	X	X	X	X	X	X	X	X									
Mark Michaelis		X			X	X																												
Maureen Olson	X	X			X	X																				X	X	X	X	X	X			
Mike Littrel				X			X																									X		
Mike Mudge	X	X	X	X	X	X	X				X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Mollie Weis	X	X			X	X																				X	X	X	X	X	X			
Peggy Blowers	X		X	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Rachel Humphries	X				X	X																				X	X	X	X	X	X			
Renee Webb	X	X	X	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Robert Dodd	X	X		X	X	X	X																			X	X	X	X	X	X	X		
Rodney Picket		X	X				X	X																									X	X
Ron Simmons		X		X	X	X	X																									X		
Tami Judge	X				X	X		X																		X	X	X	X	X	X			
Teresa Damon	X	X	X		X	X	X																			X	X	X	X	X	X		X	X
Tom Heavey		X		X	X	X	X	X																								X		

Procurement: Budget

Six Month Procurement Prior to Capital

			YTD Total	201112	2011 Total	201201	201202	201203	201204	201205	201206	Total
Labor	920000	A & G Salaries	$189,497	48,736	$238,233	65,278	76,913	117,144	75,517	76,388	73,832	$723,305
	921010	Office Supplies Gen	$2,750		$2,750							$2,750
	7703999	One Leave				14,898	5,531	8,589	8,679	7,977	10,035	
	Labor Total		$192,247	$48,736	$240,983	$80,176	$82,444	$125,733	$84,196	$84,365	$83,867	$781,764
Non-Labor	920000	A & G Salaries	$106,118	27,292	$133,410	44,899	46,169	70,410	47,150	47,244	46,966	$507,673
	921010	Office Supplies Gen	$21,156	500	$21,656	500	500	500	500	500	500	$24,656
	923010	Outside Services Gen	$201,775	38,771	$240,546	45,800	42,200	32,000	0	0	0	$360,526
	931010	Rents General	$52,234	10,447	$62,681	10,447	10,447	10,447	10,447	10,447	10,447	$115,036
	921000	Travel				7,000	7,000	7,000	7,000	7,000	7,000	$42,000
	Non-Labor Total		$381,283	$77,010	$458,293	$108,646	$106,316	$120,357	$65,097	$65,191	$64,913	$988,813
Total Expenses			$573,530	$125,746	$699,276	$188,822	$188,760	$246,090	$149,293	$149,556	$148,780	$1,770,577
N52 Budget			$743,750	$106,250	$850,000	$188,822	$188,760	$246,090	$149,293	$149,556	$148,780	$1,921,301
Variance			$170,220	($19,496)	$150,724	$0	$0	($0)	$0	($0)	$0	$150,724

Procurement: Change Management / Communication

Project Compass will involve changing business processes, systems, and roles. Organizational Change Management (OCM) supports individual employees impacted by the change through their own transitions - from their own current state to their own future state that has been created by the implementation of the new business systems. It provides a structured and intentional approach to enable individual employees to adopt the changes required by implementing these new systems.

Specific Procurement Phase OCM goals include:

- Building organizational awareness
- Building relationships and trust
- Setting expectations
- Identifying and opening communication channels

(See Appendix B to view the Change Management Plan Overview.)
(See Appendix C to view the OCM Procurement Phase Deliverables.)

Current State Mapping

Current State Mapping

This section of the guidebook is specific to the Current State Mapping Phase of Project Compass.

Current State: Objective

The objective of capturing current state information for business processes is to reduce overall risk to Project Compass. By focusing on each business area affected by the change of the Work Management System (WMS), Customer Information (CSS) System, and Electric Gas Meter Application (EGMA), Mobile Workforce, Compliance List Manager, and METS, the probability of missing critical information in the blue print phase is significantly reduced. Missed processes or critical information within processes can result in delays and rework, impacting both the timeline and the budget of the overall project.

Additionally, the members of the teams will gain an understanding of the impact and scope of the project as they participate in mapping out their processes. This will facilitate work groups through the changes that will occur to the business as a result of Project Compass by fostering support and building familiarity. The efforts in current state mapping will jump start the future state blue print mapping phase as the data will be used in creating training documents, test scripts, and templates for the next phases in the project.

Current State: Scope

The scope includes capturing key attributes on current business processes across the lines of business. Teams comprised of Subject Matter Experts from the lines of business will focus on the essential process attributes and key data that will facilitate and accelerate the future state mapping exercises. There are currently 29 business areas and business process owners recognized that have catalogued 297 business processes to be mapped that involve direct use of WMS or CSS either now or in a future state.

The effort to capture current states began in the summer of 2011 with the Contact Center processes. The effort to capture the current states for the other 26 business areas will begin in earnest in February of 2012 and continue for 18 weeks completing in June. Each process mapping session is estimated to take 2 – 4 hours each and each team is estimated to have 6 – 8

Current State: Scope Continued

participants including a Facilitator, Recorder, Scribe, and 3 – 5 Subject Matter Experts (SME). The Project Team assembled Facilitators and Recorders to aid each business area with their mapping exercises.

(See Appendix D to view the Current State Master Inventory List.)

Current State: Process Overview

The methodology for capturing the current state maps includes identifying the affected lines of business, listing business process inventories for each business line, determining the supporting roles, identifying the resources necessary for each of the exercises, training the people who will be participating, and scheduling out the sessions to be completed by end of June 2012.

Some of the key attributes of the processes to be captured in the current state mapping exercises include the inputs, outputs, interfaces, mandates, source documents, roles, metrics, broken or inefficient processes, "wish list" functionality, and reports. The attached Visio template illustrates this information.

(See Appendix E to view the Current State Visio Template.)

Current State: Business Process Inventory

The business process owners cataloged 297 processes across 29 business areas. Attached are the inventory lists by business process area. As the current states for the processes are completed, these lists will be updated to track the progress for each business area. This information will then be reported out to the key stakeholders at regular intervals.

(See Appendix F to view sample process inventory list.)

Current State: Roles and Expectations

The roles for the mapping exercises include:

- Business Process Owner
- Facilitator
- Scribe
- Recorder
- Subject Matter Expert (SME)

Current State: Roles and Expectations Continued

(See Appendix G to view the current state guidelines and role document.)
(See Appendix H to view the current state ground rules document.)

Current State: Change Management / Communication

A Business Process Improvement update focused on the current state mapping process was provided to Directors, Managers, Process Owners, Facilitators, Recorders, and Subject Matter Experts November 2011 through February 2012. (See Procurement Change Management above for overall Change Management/Communication deliverables.)

(See Appendix I to view the BPI Current State Presentation.)

Current State: Training

All Facilitators, Recorders and SME's will be provided training prior to independently completing their assigned process mapping sessions. All training material will be posted on the Project Compass Share Point site as reference material.

Current State Training Matrix

Audience	Training Vehicle	Information
Directors/ Managers	Meeting/email	• Process Guidelines, Roles, Expectations, Resource requirements, Schedule
Business Process Owners	Classroom/meeting/email	• Process Guidelines, Roles, Expectations
Facilitators	Classroom/meeting	• Process Guidelines, Roles, Expectations • Share Point overview
	Observation	• Observe experienced Facilitator
	Feedback	• Experienced facilitator observes and provides feedback
Recorders/Scribes	Classroom/meeting	• Process Guidelines, Roles, Expectations • Share Point overview • Visio
Subject Matter Experts (SME's)	Classroom/meeting	• Process Guidelines, Roles, Expectations • Share Point overview

Current State: Schedule

The Project Compass Current State calendar will be published on a weekly basis to the public Project Compass SharePoint Site. Please note that the main schedule will be kept in the Project Compass Current State Calendar in Outlook. If there is a discrepancy between the two, then the Outlook Calendar is considered the source document.

(See Appendix J for the full Current State Mapping Schedule.)
(See Appendix K for the Current State Mapping Gantt Schedule.)

Current State: Resources

(See Appendix L for Current State Mapping Resources by Business Area)

Current State: Budget

2012 Project Compass Current State
OPER Expenses by Labor / Non-Labor

			Project	Task	Org	201202	201203	201204	201205	201206	Total Expense
	CSS	Project Compass Current State Labor	09905569	920000		40,885	80,066	78,362	54,512	17,035	$270,860
	Labor Expenses Total					**$49,633**	**$97,198**	**$97,198**	**$66,178**	**$20,681**	**$330,888**
Non-Labor	CSS	N52 - CSS Replacement Project - Supplies	09905569	921000		100	100	100	100	100	$500
	CSS	N52 - CSS Software Purchase	09905569	921000		1,000	-	-	-	-	$1,000
	Non-Labor Expenses Total					**$1,100**	**$100**	**$100**	**$100**	**$100**	**$1,500**
Total Expenses						**$50,733**	**$97,298**	**$97,298**	**$66,278**	**$20,781**	**$332,388**
Budget						**$50,733**	**$97,298**	**$97,298**	**$66,278**	**$20,781**	**$332,388**
Variance						**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Budget is based on average of $40.00 per hour burdened labor rate

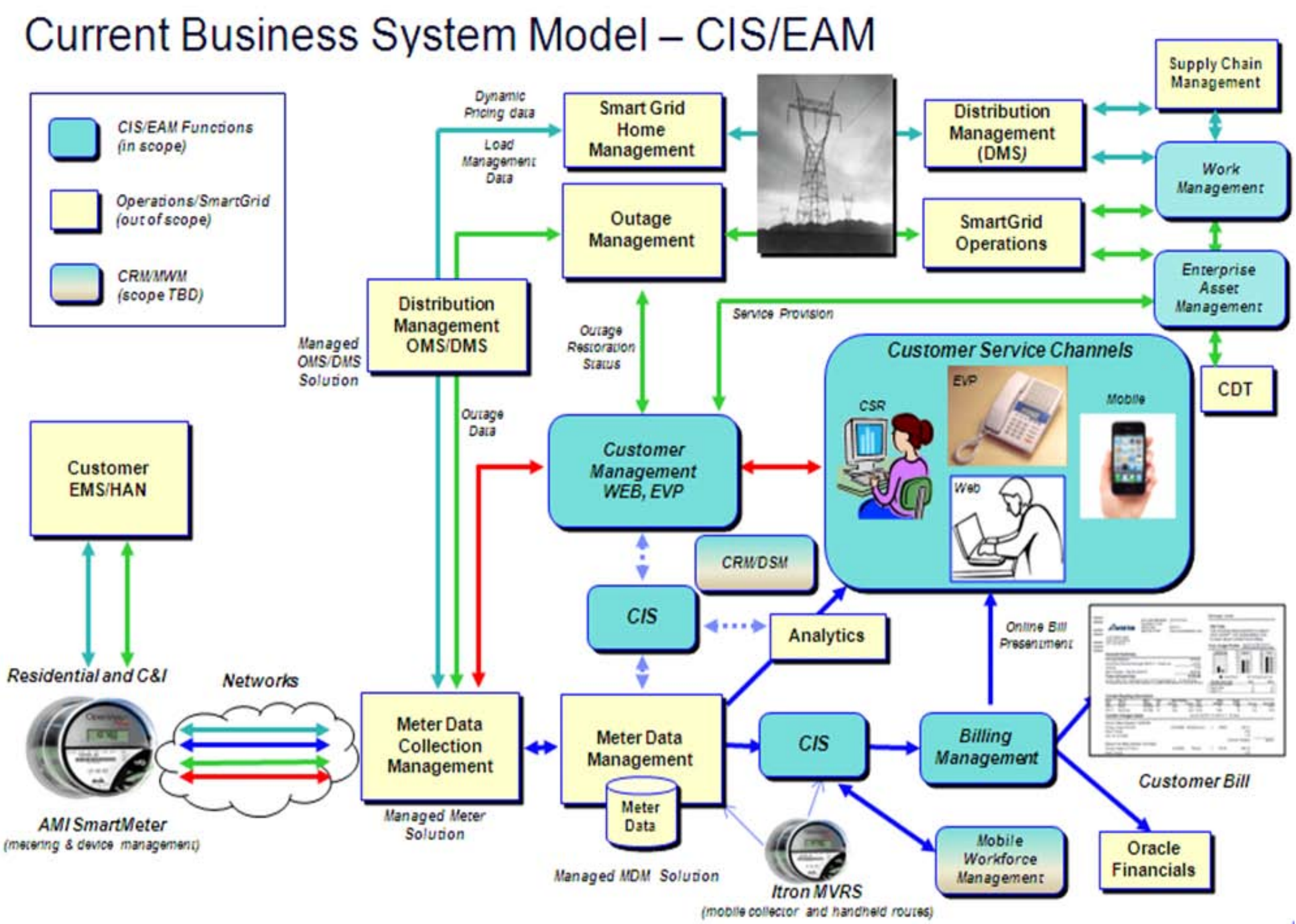
PRELIMINARY DRAFT/CONFIDENTIAL
Please note that the information contained herein is preliminary and for discussion purposes only. It does not necessarily represent the views of Company management (and may, in some cases, represent only the views of independent consultants or advisors). Accordingly, any preliminary estimates, costs or benefits, as well as the characterizations of such, are subject to change and will be revised as, and to the extent, the project proceeds.

Summary

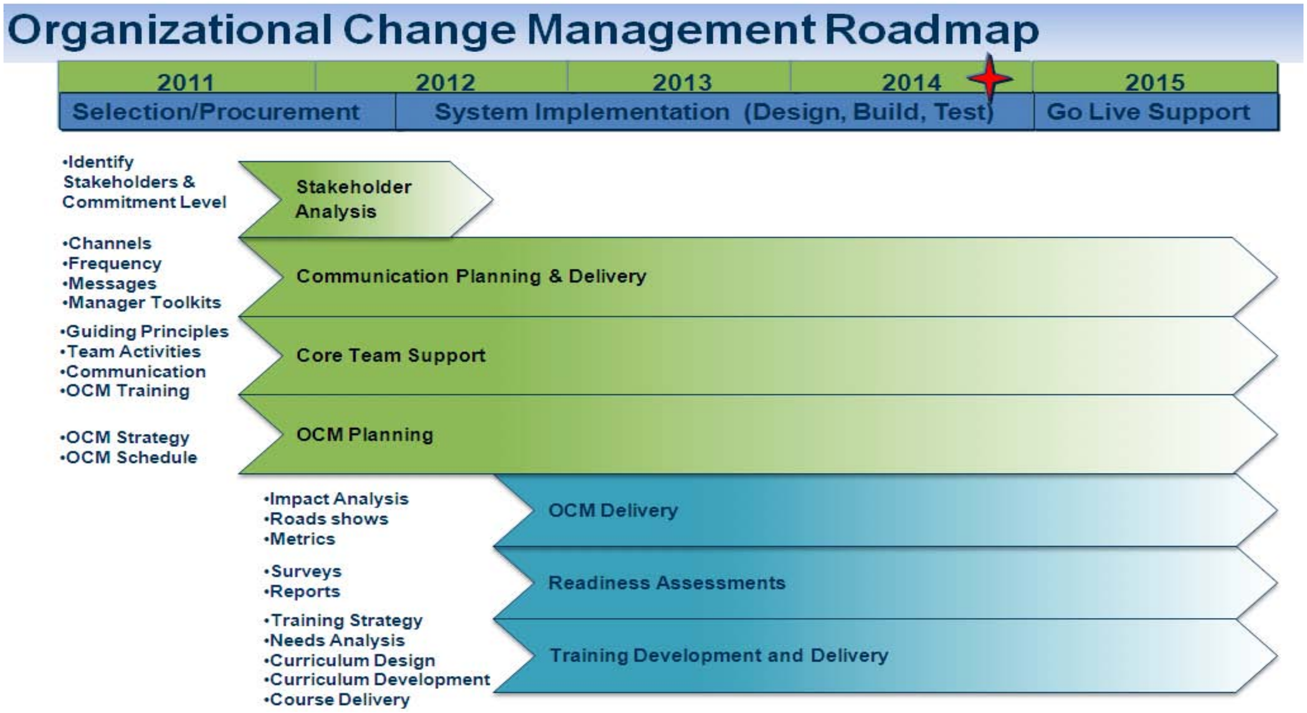
Avista's future includes the successful implementation of an enterprise business solution which replaces our homegrown, customized systems. The ability to view one customer, many locations, and one format simplifies our work, reduces costs, and will enhance our internal and external customer experience. This Project Compass Guidebook provides the detailed approach to successfully implementing the new solution.

Appendix

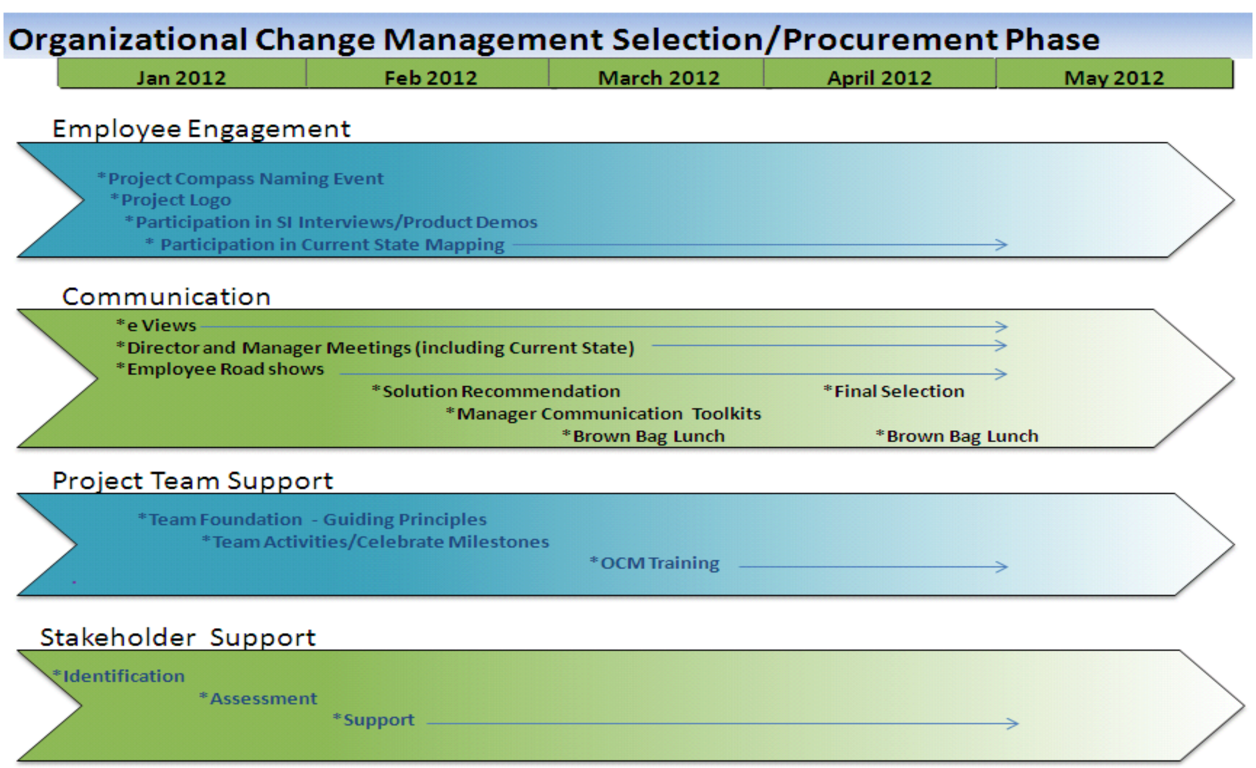
APPENDIX A: Avista's Current Business System Model



APPENDIX B: Change Management Plan Overview



APPENDIX C: OCM Procurement Phase Deliverables



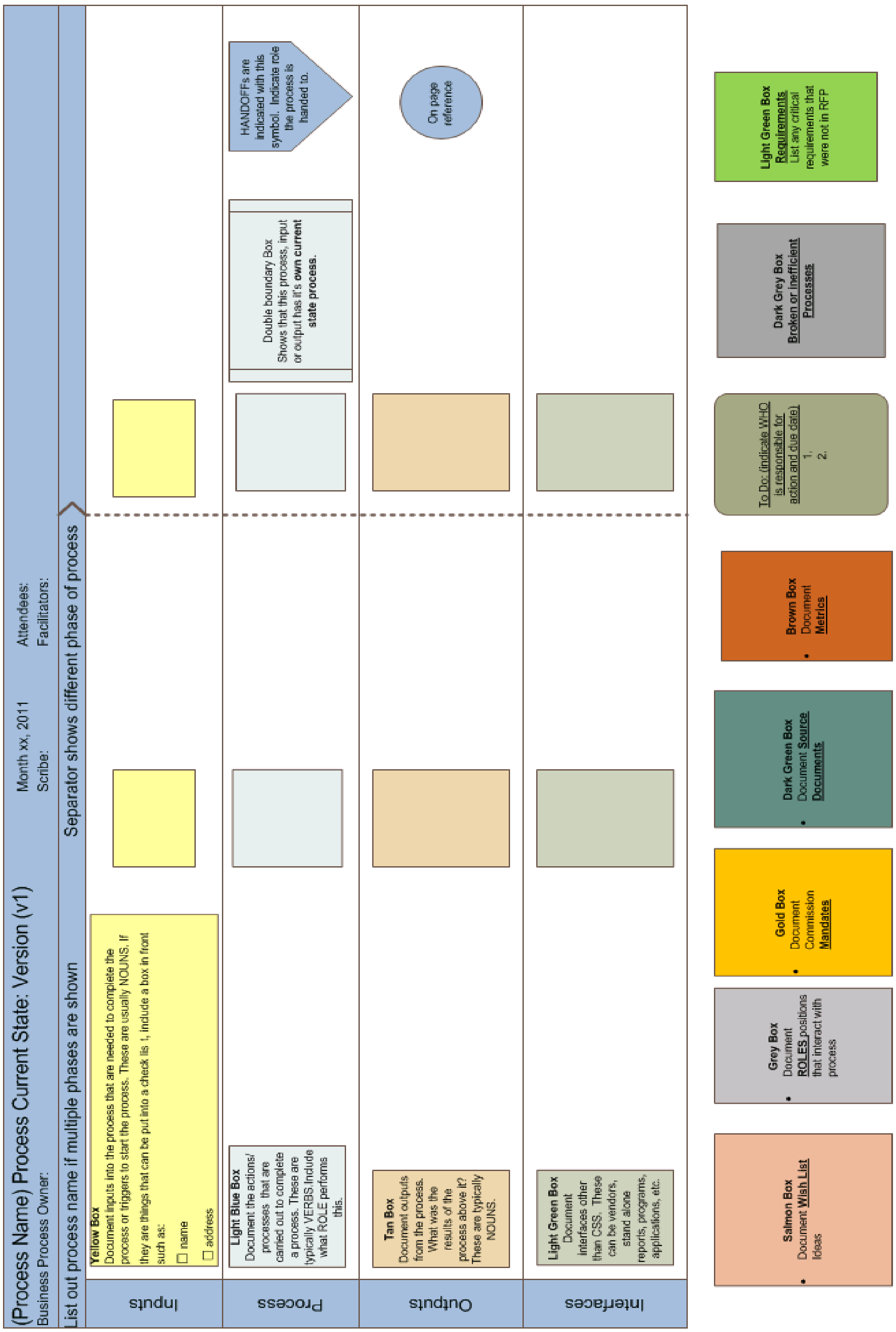
APPENDIX D: Current State Master Inventory List

Current Use Processes with CSS, WMS, Mobile

Last Update: 02-03-2012

Systems	Currently Using CSS or WMS	Business Process Area	Functional Business Leads	Business Process Owner(s)	Director	Facilitators	# of Processes	# of Current States Complete	% Complete
CSS	Yes	Contact Center: Customer Care	DJ Kinservik	Darrin Belgarde	Mike Broemeling	DJ	30	15	50%
CSS	Yes	Contact Center: Billing	Janna Loef	Kim Casey	Mike Broemeling	Janna	16	7	44%
CSS	Yes	Contact Center: Credit & Collections	Renee Webb	Jennifer Esch	Mike Broemeling	Renee	24	18	75%
CSS	Yes	Meter Reading	Janna Loef	Jackie Foss	Mike Broemeling	Janna	12		0%
CSS	Yes	Treasury/Finance	Tami Judge	Angie Hayne/Tami Judge	Diane Thoren/Adam Munson	Tami	33		0%
CSS	Yes	Rates	Ken Humphries	Ken Humphries	Liz Andrews	Ken	12		0%
CSS/EGMA	Yes	Electric Meter Shop	Janna Loef	Greg Paulson	Rick Vermeers	Janna	10		0%
CSS/EGMA	Yes	Gas Meter Shop	David Howell	David Howell	John Schwendener	Janna	13		0%
WMS/EAM	Yes	Utility Plant Accounting	Catherine Mueller	Catherine Mueller	Adam Munson	Tami	7		0%
WMS/EAM	Yes	Electric & Gas Operations	Lamont Miles & TBA	Steve Plowman/Paul Good	Al Fisher, John Schwendener	Teresa Damon	25		0%
WMS/EAM	Yes	Electric Asset Maint: Vegetation Mgmt	Rodney Pickett	Pam Luders/Larry Lee	Kevin Christie	Amber G.	4		0%
WMS/EAM	Yes	Electric Asset Maint: Wood Pole Maint	Rodney Pickett	Pam Luders/Mark Gabert	Kevin Christie	Amber G.	4		0%
WMS/EAM	Yes	Gas Compliance, Gas Eng, Prog Maint	Kevin Farrington	David Howell/ Faulkenberry	John Schwendener	Jody/Kevin	30		0%
MWM/Mobile	Yes	Mobile Gas & Electric	Renee Webb	Mike Littrel	John Schwendener	Renee	22		0%
MWM/Mobile	Yes	Central Dispatch	Lamont Miles	Garth Brandon	Scott Kinney	Jody	7		0%
CSS	Yes	DSM Residential/Low Income	Rachelle Humphrey	Rachelle Humphrey	Pat Lynch	DJ	3		0%
CSS/CRM	Yes	DSM Regulatory and other Reporting	Mark Baker	Mark Baker	Bruce Folsom	DJ	5		0%
CSS/CRM	Yes	DSM Oregon	Kerry Shrey	Kerry Shrey	Pat Lynch	DJ	3		0%
WMS/EAM/METS	No	PCB Testing and Tracking	L Miles/R. Pickett	Darrell Soyars/Rodney Pickett	Bruce Howard, Kevin Christie	Amber G.	1		0%
WMS/EAM/METS	No	Distribution Transformers	L Miles/R. Pickett	Liz St. Mark/Eric Meier	Bob Marshall, Al Fisher	Amber G.	1		0%
WMS/EAM/METS	No	EMT	Mike Magruder	Mike Magruder	Rick Vermeers	Magruder	1	1	100%
WMS/EAM/METS	No	Substation Inspections	Mike Magruder	Mike Magruder	Tim Carlberg	Magruder	1	1	100%
WMS/EAM/METS	No	Generation & Production	Bob Weisbeck	Andy Vickers/Bob Weisbeck	Tim Carlberg	Bob	17		0%
CRM	No	Marketing	Kelly Conley	Kelly Conley	Dana Anderson	DJ	5		0%
CSS/CRM	No	Commercial DSM/ Account Mgmt	Ann Carey	Ann Carey	Pat Lynch	DJ	4		0%
Totals							290	42	14%

APPENDIX E: Current State Visio Template



APPENDIX F: Sample Process Inventory Lists

Last Update: 12-02-2011

Business Area Process Owner: Mark Baker

Categ	Process	Description	Interfaces	Process Owner	Low) P	Date C Stat Cur	SME Participants
Residential rebate rep			CSS	Mark Baker	High	Ongoing	Mark Baker
Low Income rebate re			CSS	Mark Baker	High	Ongoing	Mark Baker
			SalesLogix	Mark Baker	High	Ongoing	Mark Baker, Gre Lorri Kirstein
Ad hoc and special rep			CSS or SalesLogix	Mark Baker	High	Ongoing	Mark Baker, Gre Lorri Kirstein
			SalesLogix	Mark Baker	High	Ongoing	Mark Baker, Gre Lorri Kirstein, A

APPENDIX G: Current State Guidelines and Roles Document

Current State Mapping Guidelines and Roles

Revised: February 6, 2012

For each unique business process, a Current State needs to be captured through a Current State mapping exercise. These are the guidelines and role definitions for the Business Process Owners, Facilitators, Scribes, Recorders, and Subject Matter Experts.

Mapping Exercise Overview and Roles

In each mapping session, there will be these roles:

- Business Process Owner: (BPO) Owns processes, makes key decisions, gives final approvals and sign-offs on Current State maps.
- Facilitator: Leads the sessions, watches time, facilitates closure on issues.
- Scribe: Captures information on white board.
- Recorder: Captures information in Visio.
- Subject Matter Experts: (SMEs) Provide expertise in their particular subject.

Teams may also benefit from having someone able to project information onto a screen to facilitate the discussion. In some instances, the Facilitator, the Scribe, and/or the Business Process Owner may be the same person.

The Current State process will be mapped in Visio, but should first be captured on a white board to start. The Visio template is located at:

http://sharepoint/projects/CSS/team/Business%20Process%20Current%20State/BP%20Guidelines%20and%20Master%20Documents/Template%20Current%20State%20110111.vsd

Version Control:

The BPO will be responsible to approve and sign off on the final Visio Current State maps. The status of the document should be indicated as "In Progress" on SharePoint until the final sign off, and then marked "Final" by Lauren Turner. If a change needs to occur after this, the document should be checked out, modified, forwarded to the BPO for approval, and then rechecked in with comments. When making significant changes to a Visio document, please work through Lauren Turner and she will assist with revising the version of the document.

List of Items Needed:

1. Ground Rules Poster
2. Multiple white boards with 5 swim lanes drawn on them
3. Various colored white board markers – one distinct color for each lane
4. Current State templates (a blank one and a pre-filled one with requirements)

5. Projector
6. Visio on a laptop

Business Process Owner

The <u>Business Process Owner</u> will have these responsibilities:

1. Prior to scheduling the Current State exercises, create an inventory of business processes that are integrated with the systems associated with Project Compass. These will then need to be prioritized as high, medium, or low and the SMEs will need to be identified. Please use the 80/20 rule for prioritizing. This list should be emailed to **Lauren Turner** each time it is modified so she can track the changes. She will post these on SharePoint and use them for tracking our progress.
    a. *High = Critical and/or process done on a continuous basis*
    b. *Medium = Important and/or frequent process*
    c. *Low = Rarely done, not critical to business*
2. Approve final Current State maps in a timely manner.
3. Mediate and make final decisions on process steps that are in dispute or to pick a "best practice".

Scribe

The <u>Scribe</u> will have these responsibilities:

1. Capture these elements on the board:
    a. Business process name
    b. Start and stop times
2. Capture the process on the white board in the same format as it looks on the Visio template. It is faster and easier to do this exercise on the whiteboard rather than in Visio. Use a different color dry erase pen for each lane for clarity.
3. Ask any clarifying questions that might be helpful.

Recorder

The <u>Recorder</u> will have these responsibilities:

1. Capture these elements into the Visio diagram:
    a. Business process name
    b. Date
    c. SMEs
    d. Facilitator, Scribe, Recorder
    e. Business Process Owner
    f. Start and stop times
    g. Version (typically version 1)
2. Transfer the Current State process from the white board into a Visio diagram.
3. Name the Visio Current State map with the process name and do a "save as" for the map.
4. Ask any clarifying questions that might be helpful during the Current State session.

5. Send the Visio diagram to the Facilitator when complete.

Subject Matter Experts (SMEs)

The SMEs will have these responsibilities:

1. Provide expertise about the process pertaining to their particular roles during the Current State mapping session.
2. Provide input on recommendations for the process.
3. Be respectful of others and to follow the Ground Rules.
4. Be willing and open to change, agree to disagree, and support decisions made with a positive attitude.
5. Use time wisely and efficiently by working quickly to conclusions.
6. Defer impasses to the Facilitator who may move the issue to the BPO for input and a decision.

Facilitator

The Facilitator will have the job of guiding the group through the Current State mapping process, and will have these responsibilities:

1. Organize and schedule the mapping sessions through the designated Compass Current State Outlook Calendar. Use the Mirabeau conference rooms as much as possible for the sessions. *Be sure to include the SMEs identified, and the Business Process Owner. The Scribe and Recorder will be pre-assigned to your session.*
2. Assign someone to use projector to demonstrate certain steps in the system if needed.
3. Review the Ground Rules (post them on the wall).
4. Strive to keep each session to 2-4 hours in length. ***Please be aware of the resource commitment in each session and drive to get these sessions completed as quickly and efficiently as possible.***
5. Keep the discussion moving and help the team to land on a best practice if more than one process is practiced.
6. Defer issues that are at an impasse to the Business Process Owner for resolution.
7. Ask if there are any special situations that don’t fit into the normal process.
8. Capture the key attributes (in the “swim lanes”) that the Facilitator should concentrate on include:
   - Inputs: These are the elements, triggers, and “things” needed to do the process. They are typically nouns. They may be attributes such as names, addresses, etc. (Check boxes are recommended to ease the fit/gap process that will take place later.)
   - Process: Focus on key action steps, roles, and handoffs. These are typically verbs. Capture what is manual and what is automated. There may be a need to have more than one swim lane for the process to represent different roles.
   - Outputs: Capture the results or products from the process. These are typically nouns.
   - Interfaces: The system interfaces can include CSS, WMS, Mobile, AFM, etc.
9. Send the completed Visio Current State map to the BPO to proof read and give final approval.

10. After approval from the BPO, send final Visio diagram to Lauren Turner**.** Lauren will be responsible for taking "To Do's", "Business Requirements", "Wish List", "Broken Processes", etc., and transferring them to master lists.

During the session, the Facilitator will also capture in separate boxes at the bottom:

1. Roles: Who does this process?
2. Wish list items: What would make the process more efficient? (i.e. automation v. manual)
3. Mandates: What mandates guide this process?
4. Source Documents: Which documents are sources for this process?
5. Metrics: What metrics are used from this process? What metrics would be good to have in the future?
6. "To Do's" or action items that need follow-up. Be sure to capture who is responsible and the delivery date.
7. Broken/inefficient Processes that need to be addressed (i.e. process is currently not working well and needs decision to move forward.)
8. System Requirements not in RFP.
9. Reports that are generated from or used in this process.

The Facilitator should also go over these points before or during the session:

1. Is there any pre-work to be done prior to the Current State mapping? *(ask in advance of the meeting)*
2. Ask: Are there any metrics or data that you need or are used from this process?
3. Ask: Did we uncover any critical business requirements in the Current State exercise that were not captured in the RFP? *(This question is directed mostly to the Business Process Owner.)*
4. Ensure everyone have the account number to charge time to. **09905569 920000**
5. Ensure the Business Process Owners have the "RFP – Requirements" document? It is located at: http://sharepoint/projects/CSS/Documents/Forms/AllItems.aspx?RootFolder=%2Fprojects%2FCSS%2FDocuments%2FProject%20Compass%20RFP%20Requirements&FolderCTID=0x012000CB730C15F3B8764DAD1AE2DFB621A326&View={B5B8C490-F8A1-4F64-B73A-4100DA6FDE6A}&InitialTabId=Ribbon%2EDocument&VisibilityContext=WSSTabPersistence
7. Update the BPO on any issues.
8. Look for opportunities (wish list) to optimize processes and procedures by leveraging the new system features and functionality. Ask open-ended questions to arrive at the best information.
9. Be willing and open to change, agree to disagree and support decisions made with a positive attitude.

APPENDIX H: Current State Ground Rules Document

Ground Rules

Review the mapping session guidelines and roles

Everyone participates

One conversation at a time

Technology free zone (pagers/cells quieted)

Listen as an ally – Listen for understanding

Be respectful and open to the opinion of others

Respect confidentiality

Ask clarifying questions: "Can you give me an example?"

Ask probing questions: "What would happen if…?"

Start and finish on time

APPENDIX I: BPI Current State Presentation

AVISTA

Project Compass
Business Process Improvement Update
Jody Morehouse

November 15, 2011

Agenda

- Business Process Improvement Role
- Current State Analysis
  - Process overview
  - Impact to you and your teams
  - Timeline
- Partnering for Success

Customer Service System and Work Management System Replacement — AVISTA

Business Process Improvement Role Overview

- Provide leadership in developing, monitoring, and meeting the business process improvement (BPI) objectives of Project Compass.
- Facilitate teams through the documentation of current state processes and the gathering of requirements and opportunities for improvement.
- Facilitate and/or participate on teams in the development of future state processes based on new system capabilities.
- Lead process alignment through fit-gap analysis where opportunities for process changes and/or system enhancements will be identified while ensuring customer satisfaction, process efficiency, and process quality.

Customer Service System and Work Management System Replacement — AVISTA

What is a "Current State?"

- *"It is what it is."*
  - Documents **how we are doing business today, not how we think we should do it.**
- Establishes foundation to compare the new systems to our current systems, and map out how we want to do business in the future
- *First step in aligning processes and identifying best practices*
- Opportunity to capture future process improvements

Customer Service System and Work Management System Replacement — AVISTA

What is our approach?

- Identify process owners for each impacted business area
  - 29 areas identified
- Create inventory of processes that touch the systems being replaced
  - Prioritization: 80/20 rule
  - Contact Center identified 78 processes
  - Anticipating more than 300 total processes
- For each unique business process, a current process is mapped
  - Inputs, Outputs, Key Process Steps and Interfaces are identified and documented.
  - Each mapping session has a facilitator, scribe, business process owner and any subject matter experts necessary to capture current state process.

Customer Service System and Work Management System Replacement — AVISTA

How are you impacted?

- Directors are key stakeholders (the new systems will directly impact your areas:)
  - Contact Center, Operations, Accounting, Finance, Asset Management, Central Dispatch, DSM, Marketing, Meter Reading, Rates, Engineering
- Your team's involvement will:
  - Help charter the system and processes for the future
  - Create the best efficiencies in your work streams
  - Ownership to complete current state mapping
- Members of your teams will be asked to participate in the current state, mapping sessions, and then again in the fit-gap *("future state")* sessions:
  - Mapping sessions may take 2 hours up to 2 days to complete one process

Customer Service System and Work Management System Replacement — AVISTA

How can we partner for success?

Directors:
- Support
- Stay informed
- Provide resources for current state analysis
- Provide resources for fit-gap analysis
- Hold Process Owners accountable
- Manage priorities

Compass Team:
- BPI leadership for current state analysis
- Information and guidance on future state (fit-gap)
- Proactive communication/project updates

Customer Service System and Work Management System Replacement — AVISTA

APPENDIX J: Current State Mapping Schedule

Week One

Current State Mapping Week 1 (Week of Feb. 6th)

Monday	Tuesday	Wednesday	Thursday	Friday
		Feb 8 2012	Feb 9 2012	Feb 10 2012
		8:00-12:00	12:30-4:00	10:00-2:00
		4 hrs	3.5 hrs.	4 hrs
		CR 701	CR 791	CR 701
		Electric Meter Inventory	Remote Disconnect/Reconnect	Creating Jobs
		Attendees:	**Attendees:**	**Attendees:**
		Facilitator: Janna Leaf	Facilitator: Janna Leaf	Facilitator: Teresa Damon
		Recorder: Michelle Heskett	Recorder: DJ Kinservik	Recorder: Michelle Heskett
		Scribe: Bobbi Jo Pemberton	Scribe: Renee Webb	Scribe: Janna Leaf
		Mollie Weis	DJ Kinservik	Steve Plewman
		Sarah Sather	Janna Leaf	Janna Leaf
		Mark Poirier	Patty Batters	Paul Good
		Janna Leaf	Jennifer Willis	Ted Boyle
		Greg Paulson	Greg Paulson	Lamont Miles
			Mike Littrel/Carie Mourin	Charmaine Hedit/Steve Aubuchon
		Feb 8 2012		
		10:00-12:00		
		2 hrs		
		CR 702		
		Life Support		
		Attendees:		
		Facilitator: DJ Kinservik		
		Recorder: Amber Solverson		
		Scribe: Nancy Upham		
		Debi Neumauer		
		Missy Gores		
		Tamara Carter		
		Amber Solverson		
		Renee Webb		

APPENDIX J: Current State Mapping Schedule Continued

Week 2

Current State Mapping Week 2

Monday	Tuesday	Wednesday	Thursday	Friday
Feb 13th 2012	Feb 14th 2012	Feb 15th 2012	Feb 16th 2012	Feb 17th 2012
9:00-12:00	10:00-1:30	8:00-12:00	12:30-4:00	8:00-12:00
3 hrs	3.5 hrs	4 hrs.	3.5 hrs	4 hrs
CR 140	CR 701	CR 702	CR 702	CR 702
Internal Needs Asses.	Mapping of Service Agreements	Leak Survey Follow-Up	Comment	PUC Complaint
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Bob Weisbeck	Facilitator: Teresa Damon	Facilitator: Jody Morehouse	Facilitator: DJ Kinservik	Facilitator: DJ Kinservik
Recorder: Karen Kusel	Recorder: Michelle Heskett	Recorder: Michelle Heskett	Recorder: Michelle Heskett	Recorder: Michelle Heskett
Jerry Cox	Scribe: Janna Leaf	Scribe: Bobbi Jo Pemberton	Scribe: Amber Solverson	Scribe: Amber Solverson
Hull	Steve Aubuchon/Connie Gorman	Shawn Gallagher	Amber Solverson	Tamara Carter
Alan Lackner	Paul Good/Lamont Miles	Sonia Johnson	Deb Noah	Amanda Reinhardt
Karen Terpak	Michelle Heskett/DJ Kinservik	Kath Cordery	Nancy Upham	Amber Solverson
Andy Vickers	Karen Cornwell/Janna Leaf	Virgina Omoto		Deb Noah
Steve Wenke	Ted Boyle/Steve Plewman	Mike Faulkenberry		
	Judy Olson	Robert Cloward		

Feb 13th 2012	Feb 14th 2012	Feb 15th 2012	Feb 16th 2012
1:00-5:00	8:00-12:00	12:00-4:00	8:00-11:00
4 hrs.	4 hrs	4 hrs.	2 hrs.
CR 702	CR 702	CR 702	CR 140
REVCAE, REVCSS, REVHBL, and REVCORR Processing	Leak Survey	CSSCAE & SJ451 GL & Projects Transactions Processing	Veg. Mgmt. Process 1 of 2 (Building a Job)
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Tami Judge	Facilitator: Jody Morehouse	Facilitator: Tami Judge	Facilitator: Amber Gifford
Recorder: Amber Solverson	Recorder: DJ Kinservik	Recorder: Amber Solverson	Recorder: Cherie Hirschberger
Scribe: Janna Leaf	Scribe: Amber Solverson	Scribe: Janna Leaf	Scribe: None Needed
Karen Doran	Shawn Gallagher	Karen Doran	Pam Luders
Mollie Weis	Sonia Johnson	Janna Leaf	Larry Lee
Cindy Healy	Robert Cloward	Mollie Weis	Chris Richardson
Janna Leaf	Virgina Omoto	Maureen Olson	Cherie Hirschberger
Adam Munson	Kevin Farrington	Cindy Healy	
Maureen Olson	Mike Faulkenberry	Adam Munson	

Feb 14th 2012
12:30-4:00
3.5 hrs
CR 702
Field Request (EMS, Meter Reading)
Attendees:
Facilitator: Renee Webb
Recorder: DJ Kinservik
Scribe: Amber Solverson
Nancy Upham
Theresa Reimer
Jackie Foss
Sarah Sather

APPENDIX J: Current State Mapping Schedule Continued

Week 3

Current State Mapping Week 3

Monday	Tuesday	Wednesday	Thursday	Friday
Feb 20th 2012	Feb 21st 2012	Feb 22nd 2012	Feb 23rd 2012	Feb 24th 2012
10:00-2:00	8:00-12:00	8:00-12:00	1:00-4:00	9:00-12:00
4 hrs	4 hrs	4 hrs.	3 hrs	3 hrs
CR 701	CR 701	CR 701	CR 145	CR 412A
Locates/Permits/Right of Way Tasks	Elec Meter Shop Testing	CSSCAE & SJ451 GL Transactions: Suspense & Clearing of Suspense; Unpostable; Return Payments	GOC Management	Campaign Mgmt.
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Teresa Damon	Facilitator: Janna Leaf	Facilitator: Tami Judge	Facilitator: Bob Weisbeck	Facilitator: DJ Kinservik
Recorder: Michelle Heskett	Recorder: Amber Solverson	Recorder: Michelle Heskett	Recorder: Karen Kusel	Recorder: Amber Solverson
Scribe: Janna Leaf	Scribe: Nancy Upham	Scribe: Janna Leaf	Scribe	Scribe: Kelly Conley
Nancy Carrol/Ted Boyle	Robert Dodd	Karen Doran	Steve Esch	Kelly Conley/Rob Wagner
Steve Aubuchon/Frank Binder	Mark Poirier	Janna Leaf	Ron Hargrave	Marry Cozza Broemeling
Todd Cornell/Paul Good	Sarah Sather	Gayle Gonser	Alan Lackner	Mary Tyrie/Scott Phipps
Lamont Miles/Connie Gorman	Greg Paulson	Angie Hayne	Karen Terpak	Colette Bottinelli
Genna Lehti/Michelle Heskett	Judy Olson	Denise Burns/Sue Senescall	Andy Vickers	Dana Anderson
Darrell Soyars/Tim Mair		Jeannie Schmidt/Gudu Fischer	Jerry Cox	Scott Steele
Luann Weingart/Steve Plewman				
	Feb 21st 2012	Feb 22nd 2012		Feb 24th 2012
	1:00-4:30	8:00-11:00		10:00-2:30
	3.5 hrs.	2 hrs.		4.5 hrs
	CR 702	CR 145		CR 702
	Gas Unit Assembly Maintenance	Veg. Mgmt. - Process 2 of 2 (WMS/CSS)		Gas Trouble, Other See Comments, CO Investigation
	Attendees:	**Attendees:**		**Attendees:**
	Facilitator: Kevin Farrington	Facilitator: Amber Gifford		Facilitator: Kevin Farrington
	Recorder: Bobbi Jo Pemberton	Recorder: Cherie Hirschberger		Recorder: Michelle Heskett
	Scribe: Nancy Upham	Scribe: Amber Gifford		Scribe: Bobbi Jo Pemberton
	Dan Wisdom	Pam Luders		David Howell
	Janna Leaf	Larry Lee		Jody Morehouse
	David Howell	Chris Richardson		Mike Littrel
	Mitch Cornwell	Cherie Hirschberger		

Week 4

Current State Mapping Week 4

Monday	Tuesday	Wednesday	Thursday	Friday
	Feb 28th 2012	Feb 29th 2012		
	8:00-12:00	1:00-4:00		
	4 hrs.	3 hrs.		
	CR 702	CR 702		
	Code 5, Avista Side/Customer	Code 9 and Grade 1		
	Attendees:	**Attendees:**		
	Facilitator: Kevin Farrington	Facilitator: Kevin Farrington		
	Recorder: Amber Solverson	Recorder: Amber Solverson		
	Scribe: Bobbi Jo Pemberton	Scribe: Bobbi Jo Pemberton		
	Mike Littrel	David Howell		
	David Howell	Mike Littrel		
	Linda Burger	Linda Burger		
	Jenny Bushnell	Jenny Bushnell		

APPENDIX J: Current State Mapping Schedule Continued

Week 5

Current State Mapping Week 5

Monday	Tuesday	Wednesday	Thursday	Friday
March 5th 2012		March 7th 2012	March 8th 2012	
10:00-2:00		8:00-10:00	1:00-4:30	
4 hrs		2 hrs	3.5 hrs.	
CR 701		CR 701	CR 702	
Remarks Field/Work Folders		Refunds & Unclaimed Processing	Moveable Pipe Inspection	
Attendees:		**Attendees:**	**Attendees:**	
Facilitator: Teresa Damon		Facilitator: Tami Judge	Facilitator: Kevin Farrington	
Recorder: Michelle Heskett		Recorder: Amber Solverson	Recorder: Amber Solverson	
Scribe: Janna Leaf		Scribe: Janna Leaf	Scribe: Nancy Upham	
DJ Kinservik/Michelle Heskett		Karen Doran	Linda Burger	
Steve Aubuchon/Steve Plewman		Janna Leaf	David Howell	
Sheila Ward/Renee Webb		Laura Brittain	Jenny Bushnell	
Frank Binder/Ted Boyle		Amanda Reinhardt		
Lamont Miles/Sheryl Florance		Kerry Shroy		
Paul Good/Patti Horbiowski				
		March 7th 2012	March 8th 2012	
		10:00-12:00	10:00-2:00	
		2 hrs	4 hrs.	
		CR 701	CR 701	
		Sales Tickets	Developments Financials	
		Attendees:	**Attendees:**	
		Facilitator: Tami Judge	Facilitator: Teresa Damon	
		Recorder: Amber Solverson	Recorder: Michelle Heskett	
		Scribe: Janna Leaf	Scribe: Janna Leaf	
		Karen Doran	Connie Gorman	
		Janna Leaf	Ken Carlson	
		Tami Judge	Sheryl Florance	
		Gayle Gonser	Linda Fleming	
		Howard Grimsrud	Michelle Heskett	
		Kerry Shroy	Paul Good	
			Steve Aubuchon	
			Frank Binder/Lamont Miles	
			Ted Boyle/Steve Plewman	
		March 7th 2012		
		1:00-5:00		
		4 hrs.		
		CR 702		
		Gas Trouble, Damage No Leak/ Residual Follow-Up		
		Attendees:		
		Facilitator: Kevin Farrington		
		Recorder: Michelle Heskett		
		Scribe: Margie Clarity		
		Karen Doran		
		Janna Leaf		
		Tami Judge		
		Gayle Gonser		
		Howard Grimsrud		
		Kerry Shroy		

APPENDIX J: Current State Mapping Schedule Continued

Week 6

Current State Mapping Week 6

Monday	Tuesday	Wednesday	Thursday	Friday
March 12th 2012	March 13th 2012	March 14th 2012	March 15th 2012	March 16th 2012
9:00-12:00	9:30-12:00	10:00-2:30	12:30-4:00	1:00-3:00
3 hrs	2.5 hrs	4.5 hrs	3.5 hrs	2 hrs
CR 145	CR702	CR 701	CR 701	CR 701
GCM Mgmt	Switched Meters	Assigning Materials/Asphalt Concrete Repair	Retire Elec Met Equip./Meter Test Boards	Online Cash/Medford
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Bob Weisbeck	Facilitator: Janna Leaf	Facilitator: Teresa Damon	Facilitator: Janna Leaf	Facilitator: Tami Judge
Recorder: Karen Kusel	Recorder: Margie Clarity	Recorder: Michelle Heskett	Recorder: Michelle Heskett	Recorder: Michelle Heskett
Scribe: Weisbeck to Provide	Scribe: Deb Noah	Scribe: Janna Leaf	Scribe: Deb Noah	Scribe: Janna Leaf
Andy Vickers	Theresa Reimer	Michelle Heskett/Steve Aubuchon	Janna Leaf	Karen Doran
Ron Hargrave	Gayle Gonser	Frank Binder/Paul Good	Mark Poirier	Janna Leaf
Alan Lackner	Heather Acord	David Scalido/Ted Boyle	Sarah Sather	Denise Burns
Karen Terpak		Karen Cornwell/Lamont Miles	Mollie Weis	Angela Hayne
Steve Wenke		Steve Plewman/Marshall Law	Robert Dodd	Sue Senescall
Wiggins/Cox		Maria Sullivan/Patti Horobiowski	Greg Paulson	Debbie Williams
March 12th 2012	March 13th 2012		March 15th 2012	March 16th 2012
8:30-11:30	10:00-12:00		8:00-11:00	3:00-5:00
3 hrs	2 hrs		2 hrs.	2 hrs
CR 702	CR 412 B		CR 702	CR 701
Special Handling	Tracking Enrollments/Terminations		Client Relationship Management, Proactive / Reactive Monthly Reporting	Online-Cash/Cust Serv - Recoveries
Attendees:	**Attendees:**		**Attendees:**	**Attendees:**
Facilitator: DJ Kinservik	Facilitator: DJ Kinservik		Facilitator: DJ Kinservik	Facilitator: Tami Judge
Recorder: Nancy Upham	Recorder: Amber Solverson		Recorder: Amber Solverson	Recorder: Michelle Heskett
Scribe: Deb Noah	Scribe: Kelly Conley		Scribe: Kelly Conley	Scribe: Janna Leaf
Theresa Reimer	Kelly Conley		Ann Carey	Karen Doran
Amber Solverson	Mary Cozza Broemeling		Sue Baldwin	Tami Judge
Deb Noah	Mary Tyrie		Catherine Bryan	Janna Leaf
	Colette Bottinelli		Kerry Shroy	Denise Burns
	Dana Anderson/ Scott Phipps			Angela Hayne/Amanda Ghering
	Scott Steele/Rob Wagner			Sue Senescall/Kim Styles
	March 13th 2012		March 15th 2012	March 16th 2012
	12:30-4:00		1:00-5:00	8:30-11:30
	3.4		4 hrs.	3 hrs.
	CR 702		CR 702	CR 701
	Diversion		AC Inspection	Elec Mtr Shop Testing - Selection and Reporting
	Attendees:		**Attendees:**	**Attendees:**
	Facilitator: Renee Webb		Facilitator: Jody Morehouse	Facilitator: Janna Leaf
	Recorder: Michelle Heskett		Recorder: Amber Solverson	Recorder: Bobbie Jo Pemberton
	Scribe: Nancy Upham		Scribe: Bobbi Jo Pemberton	Scribe: Nancy Upham
	Alene Clayton		Shawn Gallagher	Judy Olson
	Heather Acord		Sonia Johnson	Bob Hooper
	Greg Paulson		Erika Jacobs	Shana Gail
	Theresa Reimer		Robert Cloward	Mark Poirier
	Kim Casey		Virginia Omoto	Sarah Sather
			Mike Faulkenberry/Jenny Bushnell	Greg Paulson
	March 13th 2012			March 16th 2012
	8:00-11:00			8:30-11:30
	3 hrs.			3 hrs.
	CR 140			CR 701
	Maps, Work Plan, Inspection Work, FollowUp Work			Elec Mtr Shop Testing - Selection and Reporting
	Attendees:			**Attendees:**
	Facilitator: Amber Gifford			Facilitator: Janna Leaf
	Recorder: Cherie Hirschberger			Recorder: Deb Noah
	Scribe: Amber Gifford			Scribe: Amber Solverson
	Pam Luders			Judy Olson
	Mark Gabert			Bob Hooper
	Ivan Rounds			Shana Gail
	Cherie Hirschberger			Mark Poirier
				Sarah Sather
				Greg Paulson
				March 16th 2012
				10:00-2:00
				4 hrs.
				CR 702
				Moveable Pipe Pt. 2 Follow-Up etc.
				Attendees:
				Facilitator: Kevin Farrington
				Recorder: Margie Clarity
				Scribe: DJ Kinservik
				Linda Burger
				David Howell
				Jenny Bushnell

APPENDIX J: Current State Mapping Schedule Continued

Week 7

Current State Mapping Week 7

Monday	Tuesday	Wednesday	Thursday	Friday
March 19th 2012	March 20th 2012	March 21st 2012	March 22nd 2012	March 23rd 2012
10:00-2:00	8:30-11:30	12:30-2:30	1:30-4:00	8:30-11:30
4 hrs	2 hrs	2 hrs	3.5 hrs	3 hrs
CR 701	CR 702	CR 412B	CR 701	CR 702
Job Design/Estimates	Third Party Notification	Communication Preferences	DSM, Residential Rebate Processing & Payment	Information Request
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Teresa Damon	Facilitator: DJ Kinservik	Facilitator: DJ Kinservik	Facilitator: DJ Kinservik	Facilitator: DJ Kinservik
Recorder: Michelle Heskett	Recorder: Amber Solverson	Recorder: Amber Solverson	Recorder: Amber Solverson	Recorder: Deb Noah
Scribe: Janna Leaf	Scribe: Deb Noah	Scribe: Kelly Conley	Scribe: Rachelle Humphrey	Scribe: Amber Solverson
Steve Plewman/Michelle Heskett	Amanda Reinhardt	Kelly Conley	Rachelle Humphrey	Amber Solverson
Lamont Miles/Mark Hansen	Tamara Carter	Mary Cozza Broemeling	Chris Drake	Deb Noah
Ted Boyle/Paul Good	Deb Noah	Mary Tyrie/Tom Heavey	Renee Coelho	Nancy Upham
Kelly Donahoue/Steve Aubuchon		Colette Bottinelli	Renesha Conley/Kathy Carpenter	Rachelle Humphrey
Frank Binder		Dana Anderson/Mary Inman	Roxanne Williams	
		Scott Steele/Scott Phipps	Kerry Shroy/Stacie Friend	

March 20th 2012	March 21st 2012	March 22nd 2012	March 23rd 2012
12:30-4:00	8:00-12:00	8:00-12:30	9:00-12:00
3.5 hrs	4 hrs.	4.5 hrs.	3 hrs
CR 702	CR 702	CR 702	CR 145
Collection Not. Action Card Mins.	Cathodic Annual Inspections	Meter Reading Access Problems, Reading Remarks and Instructions	Construction Mgmt and Inspection
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Renee Webb	Facilitator: Jody Morehouse	Facilitator: Janna Leaf	Facilitator: Bob Weisbeck
Recorder: Michelle Heskett	Recorder: Deb Noah	Recorder: Deb Noah	Recorder: Karen Kusel
Scribe: Deb Noah	Scribe: Bobbie Jo Pemberton	Scribe: Michelle Heskett	Scribe: Provided by Weisbeck
Amanda Reinhardt	Mike Faulkenberry	Jackie Foss	Cody Krogh
Tamara Carter	Gary Douglas	Allyn Smith	Debbie Biggs
	Pamela Horne	Robin Hunter	John Hamill
	Erika Jacobs		Eric Atkinson
			Lin Miller
			Tammie Miller/Tom Zimmerer

March 20th 2012
1:00-4:00
3 hrs.
CR 145
Engineer Work Assignment Process
Attendees:
Facilitator: Bob Weisbeck
Recorder: Karen Kusel
Scribe: Provided by Weisbeck
Steve Wenke
Glen Farmer
Mike Gonnella
John Hamill
Jason Graham
Kristina Newhouse/Ryan Bean

March 20th 2012
1:00-5:00
4 hrs.
CR 701
AC Follow Up Orders
Attendees:
Facilitator: Jody Morehouse
Recorder: Amber Solverson
Scribe: Bobbi Jo Pemberton
Shawn Gallagher
Sonia Johnson
Kathy Cordery
Erika Jacobs
Robert Cloward/ Jenny Bushnell
Virginia Omoto/Mike Faulkenberry

APPENDIX J: Current State Mapping Schedule Continued

Week 8

Current State Mapping Week 8

Monday	Tuesday	Wednesday	Thursday	Friday
March 26th 2012	March 27th 2012	March 28th 2012	March 29th 2012	March 30th 2012
8:00-5:00	1:00-5:00	10:00-2:00	9:00-11:00	8:00-12:00
8 hrs	4 hrs.	4 hrs.	2 hrs.	4 hrs.
CR 701	CR 701	CR 701	CR 428	CR 702
Oracle AR processes that may be moved to new CIS system	Isolated Steel Survey	Work location tabs or premise-assigning the jobs	DSM, Low Income Weatherization Processing and Payment	Tax Reporting
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Tami Judge	Facilitator: Jody Morehouse	Facilitator: Teresa Damon	Facilitator: DJ Kinservik	Facilitator: Tami Judge
Recorder: Michelle Heskett	Recorder: Amber Solverson	Recorder: Michelle Heskett	Recorder: Amber Solverson	Recorder: Deb Noah
Scribe: Janna Leaf	Scribe: Nancy Upham	Scribe: Janna Leaf	Scribe: Rachelle Humphrey	Scribe: Janna Leaf
Karen Doran	Gary Douglas	Steve Plewman/Lamont Miles	Rachelle Humphrey	Karen Doran
Janna Leaf	Pamela Horne	Sheryl Florance/Paul Good	Renee Coelho	Janna Leaf
Gudu Fischer	Erika Jacobs	Ted Boyle/Steve Aubuchon	Chris Drake	Catherine Cooper
Monica Bannon	Mike Faulkenberry	Frank Binder/Connie Gorman	Kristine Meyer	Yvonne Cook
Jeannie Schmidt		Michelle Heskett		Don Falkner
Catherine Mueller				

March 26th 2012	March 27th 2012		March 29th 2012	
1:00-5:00	1:00-5:00		12:30-4:00	
4 hrs.	4 hrs.		3.5 hrs	
CR 702	CR 702		CR 702	
CP Follow Up	Cash Processing		Returned Payments	
Attendees:	**Attendees:**		**Attendees:**	
Facilitator: Jody Morehouse	Facilitator: Tami Judge		Facilitator: Renee Webb	
Recorder: Amber Solverson	Recorder: Bobbi Jo Pemberton		Recorder: Michelle Heskett	
Scribe: Deb Noah	Scribe: Janna Leaf		Scribe: Janna Leaf	
Gary Douglas	Karen Doran		Kym Stiles	
Gary Horne	Janna Leaf		Deb Noah	
Katy Cordrey	Denise Burns		Amanda Reinhardt	
Erika Jacobs	Angela Hayne			
Mike Faulkenberry	Sue Senescall			
	Rosemary Coulson/Diane Thorne			

March 29th 2012
1:00-4:00
3 hrs.
CR 145
As Built Drawing Mgmt.
Attendees:
Facilitator: Bob Weisbeck
Recorder: Karen Kusel
Scribe: Weisbeck to Provide
Steve Wenke/Mike Gonnella
John Hamill/Glen Farmer
Ron Hargrave/Mary Jensen
Tom Whitehead/Jeff Marsh
Clint Laws

APPENDIX J: Current State Mapping Schedule Continued

Week 9

Current State Mapping Week 9

Monday	Tuesday	Wednesday	Thursday	Friday
April 2nd 2012		April 4th 2012		April 6th 2012
8:30-11:30		10:00-2:30		8:00-11:00
3 hrs		4.5 hrs		2 hrs
CR 702		CR 701		CR 702
Email Address		Job Scheduling		Sales including Competitive Situations and Contract Negotiation
Attendees:		**Attendees:**		**Attendees:**
Facilitator: DJ Kinservik		Facilitator: Teresa Damon		Facilitator: DJ Kinservik
Recorder: Deb Noah		Recorder: Michelle Heskett		Recorder: Amber Solverson
Scribe: Nancy Upham		Scribe: Janna Leaf		Scribe: Janna Leaf
Amber Solverson		Lamont Miles/Ted Boyle		Ann Carey
Nancy Upham		Steve Aubuchon		Sue Baldwin
Stacie Friend		Deb Denney/Katy Cordery		Catherine Bryan
Deb Noah		Steve Plewman/Paul Good		
		Charmaine Heidt/Eric Rosentrater		
		Kelly Donohue/Shane Pacini		

APPENDIX J: Current State Mapping Schedule Continued

Week 10

Current State Mapping Week 10

Monday	Tuesday	Wednesday	Thursday	Friday
April 9th 2012	April 10th 2012	April 11th 2012	April 12th 2012	April 13th 2012
1:00-4:00	10:00-3:00	9:00-11:00	8:30-11:30	9:00-12:00
3 hrs.	5 hrs.	2 hrs.	2 hrs.	3 hrs.
CR 702	CR 701	CR 428	CR 702	CR 145
Newsletters/Customer Communication	Invoice Job prior to construction, Invoice Job when closed	Net-Metering: Renewable (Schedule 63)	Merge Customer	Engineer Information Management
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: DJ Kinservik	Facilitator: Teresa Damon	Facilitator: DJ Kinservik	Facilitator: DJ Kinservik	Facilitator: Bob Weisbeck
Recorder: Amber Solverson	Recorder: Michelle Heskett	Recorder: Amber Solverson	Recorder: Deb Noah	Recorder: Karen Kusel
Scribe: Janna Leaf	Scribe: Janna Leaf	Scribe: Rachelle Humphrey	Scribe: Amber Solverson	Scribe: Provided by Weisbeck
Ann Carey	Linda Fleming/Tia Benjamin	Rachelle Humphrey	Deb Noah	Steve Wenke
Kelly Conley	Jeanie Schmidt/Lamont Miles	Renee Coelho	Gayle Gonser	Mike Gonnella
Sue Baldwin	Steve Aubuchon/Steve Plewman	Chris Drake	Jan Casis	John Hamill
Cathreine Bryan	Paul Good/Raven Perry	Ann Carey	Betsy Townsend	Glen Farmer
	Michelle Heskett			Ron Hargrave/Mary Jensen
	Frank Binder			Andy Vickers

April 9th 2012
8:30-12:00
1.5 hrs.
CR 702
CIAC's
Attendees:
Facilitator: Catherine Mueller
Recorder: Bobbi Jo Pemberton
Scribe: Janna Leaf
Howard Grimsrud
Sue Mullerleile

April 11th 2012
1:00-5:00
4 hrs.
CR 702
Rates - LIRAP Application Process
Attendees:
Facilitator: Janna Leaf
Recorder
Scribe
Jennifer Smith
Ken Humphries

April 11th 2012
9:30-3:30
6 hrs.
CR 701
Service Work Resolution
Attendees:
Facilitator: Teresa Damon
Recorder: Michelle Heskett
Scribe: Janna Leaf
Lamont Miles
Steve Plewman
Paul Good
Michelle Heskett

APPENDIX J: Current State Mapping Schedule Continued

Week 11

Current State Mapping Week 11

Monday	Tuesday	Wednesday	Thursday	Friday
April 16th 2012	April 17th 2012	April 18th 2012	April 19th 2012	April 20th 2012
8:30-11:30	10:00-3:00	1:00-3:00	9:30-12:00	8:30-11:30
2 hrs.	5 hrs.	2 hrs.	2.5 hrs	3 hrs.
CR 702	CR 701	CR 702	CR 145	CR 701
Problem Customer	Receive Payments-Process Refunds for Line Extension Certificates	Uncollectiable Analysis	Invoicing Process	C/I DSM Projects
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: DJ Kinservik	Facilitator: Teresa Damon	Facilitator: Tami Judge	Facilitator: Bob Weisbeck	Facilitator: DJ Kinservik
Recorder	Recorder	Recorder	Recorder	Recorder
Scribe	Scribe	Scribe	Scribe	Scribe
Amber Solverson	Jeannie Schmidt/Steve Aubuchon	Janna Leaf	Cody Krogh	Ann Carey
Deb Noah	Steve Plewman/Paul Good	Ian McLelland	Tim Carlberg	Sue Baldwin
Gayle Gonser	Linda Fleming/Doug Donahoo	Amanda Reinhardt	Debbie Briggs	Catherine Bryan
Greg Paulson	Frank Binder/Raven Perry	Catherine Cooper	Andrea Marlowe	Camielle Martin/Kerry Shroy
Mike Littrel	Ted Boyle/Lamont Miles		Andy Vickers/Tammie Miller	Greta Zink/Lorri Kirstein
	Michelle Heskett/Judy Olson		Steve Wenke	Renee Coelho/Tom Lienhard

Thursday	Friday
April 19th 2012	April 20th 2012
8:30-12:30	1:00-4:30
4 hrs	3.5 hrs.
CR 702	CR 702
Meter Reading Rerouting, Problem Cust, Apt Usage, ERT Search	Exposed Pipe (Session 2)
Attendees:	**Attendees:**
Facilitator: Janna Leaf	Facilitator: Kevin Farrington
Recorder	Recorder
Scribe	Scribe
Jackie Foss	David Howell
Robin Hunter	Linda Burger
Allyn Smith	Sonia Johnson

Thursday
April 19th 2012
1:00-3:30
2.5 hrs
CR 702
CAE Approval Process
Attendees:
Facilitator: DJ Kinservik
Recorder
Scribe
Galen Lorenz
Darrin Belgarde
Janna Leaf

Thursday
April 19th 2012
1:00-4:30
3.5 hrs.
CR 701
Exposed Pipe (Session 1)
Attendees:
Facilitator: Kevin Farrington
Recorder
Scribe
David Howell
Linda Burger
Sonia Johnson
Liz St. Mark

APPENDIX J: Current State Mapping Schedule Continued

Week 12

Current State Mapping Week 12

Monday	Tuesday	Wednesday	Thursday	Friday
April 23rd 2012	April 24th 2012	April 25th 2012	April 26th 2012	April 27th 2012
8:30-11:30	8:30-12:00	8:30-11:30	9:00-10:00	9:00-11:00
3 hrs.	3.5 hrs	3 hrs.	1 hr.	2 hrs
CR 702	CR 702	CR 702	Medford Office	CR 702
Code Word	Meter Read Exceptions, On Cycle Billing, Estimation Current State	Rate Schedule Change	Current State Log and Manage Audit Requests	Request Duplicate Bill
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: DJ Kinservik	Facilitator: Janna Leaf	Facilitator: DJ Kinservik	Facilitator: Kerry Shroy	Facilitator: DJ Kinservik
Recorder	Recorder	Recorder	Recorder	Recorder
Scribe	Scribe	Scribe	Scribe	Scribe
Amber Solverson	Theresa Reimer	Gayle Gonser	Lisa McGarity	Amber Solverson
Deb Noah	Heather Acord	Jan Cassis		
Nancy Upham	Mollie Weis	Theresa Reimer		
	DJ Kinservik			

Monday	Tuesday	Wednesday	Thursday	Friday
April 23rd 2012	April 24th 2012	April 25th 2012	April 26th 2012	April 27th 2012
9:00-1:00	12:30-3:30	9:30-3:30	10:00-11:00	8:00-12:00
4 hrs.	3 hrs.	6 hrs.	1 hr.	4 hrs.
CR 701	CR 702	CR 701	Medford Office	CR 701
Gas Meter Annual Test Selection and Performance Reporting	Remove and Change Metered / Unmetered Services	Job Stage Notebook - Status Jobs	Process Weatherization Incentive Payments	Health Check Monitors (Cent. Disp)
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Janna Leaf	Facilitator: DJ Kinservik	Facilitator: Teresa Damon	Facilitator: Kerry Shroy	Facilitator: Jody Morehouse
Recorder	Recorder	Recorder	Recorder	Recorder
Scribe	Scribe	Scribe	Scribe	Scribe
Steve Williams	Heather Acord	Ted Boyle/Paul Good	Lisa McGarity	Jeff Potter
David Howell	Theresa Reimer	Steve Aubuchon/Judy Olson		Mike Littrel
Judy Olson	Sarah Sather	Deb Denney/Frank Binder		Garth Brandon
Dan Whicker	Gayle Gonser	Patti Horbiowski/Linda Fleming		Mike McAllisster
	Janna Leaf	Karen Cornwell/Michelle Heskett		Reuben Arts

Monday	Tuesday	Wednesday	Thursday	Friday
April 23rd 2012	April 24th 2012		April 26th 2012	April 27th 2012
9:00-12:00	10:00-2:30		11:00-12:00	12:00-4:00
3 hrs.	4.5 hrs.		1 hr.	4 hrs.
CR 145	CR 701		Medford Office	CR 702
Unplanned Work (Drop in, Equipment Failures)	Ability to Associate Jobs, Ability to Change Jobs		Weatherization Reporting	Regulator Station Inspections, Session 1 - Industrial meter sets, reg stations, master meters
Attendees:	**Attendees:**		**Attendees:**	**Attendees:**
Facilitator: Bob Weisbeck	Facilitator: Teresa Damon		Facilitator: Kertry Shroy	Facilitator: Keving Farrington
Recorder	Recorder		Recorder	Recorder
Scribe	Scribe		Scribe	Scribe
Tim Carlberg	Lamont Miles/Frank Binder		Lisa Mcgarity	Sonia Johnson
Steve Wenke	Ted Boyle/Sheryl Florance			David Howell
Greg Lancaster	Sheila Ward/Steve Plewman			Candace Baker
Randy Pierce	Steve Aubuchon/Patti Horobiowski			
Alan Lackner	Carie Mourin/Mike Littrel			
Jerry Cox/Andy Vickers	Michelle Heskett/Paul Good			

Thursday
April 26th 2012
12:30-4:00
3.5 hrs.
Trailer
Rates: Customer Research Process
Attendees:
Facilitator: Janna Leaf
Recorder
Scribe
Ken Humphires
Shawn Bonfield

Thursday
April 26th 2012
1:00-4:00
3 hrs.
CR 701
Remarks
Attendees:
Facilitator: DJ Kinservik
Recorder
Scribe
Amber Solverson
Deb Noah
Nancy Upham

APPENDIX J: Current State Mapping Schedule Continued

Week 13

Current State Mapping Week 13

Monday	Tuesday	Wednesday	Thursday	Friday
April 30th 2012	May 1st 2012	May 2nd 2012	May 3rd 2012	May 4th 2012
9:30-11:30	9:00-12:00	8:30-11:30	1:00-4:00	8:00-12:00
2 hrs.	3 hrs.	2 hrs.	3 hrs.	4 hrs.
CR 701	CR 145	CR 702	CR 145	CR 702
Propertry Removal Notice	Budget Allocation	Estates	Work Integration Between GPSS, Transmission and Substation Design	OMT Electric Trouble
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Teresa Damon	Facilitator: Bob Weisbeck	Facilitator: DJ Kinservik	Facilitator: Bob Weis	Facilitator: Jody Morehouse
Recorder	Recorder	Recorder	Recorder	Recorder
Scribe	Scribe	Scribe	Scribe	Scribe
Lamont Miles/Linda Fleming	Tim Carlberg	Amber Solverson	Andy Vickers	Mike Littrel
Ted Boyle/Steve Plewman	Steve Wenke	Deb Noah	Greg Lancaster	Garth Brandon
Patti Horobiowski/Janna Leaf	Andy Vickers	Amanda Reinhardt	Randy Pierce	Jeff Potter
Michelle Heskett/Paul Good	Andrea Marlowe	Nancy Upham	Cody Krogh	Mike McAllistser
Steve Aubuchon/Frank Binder	Alan Lacker		Mike Magruder	Reuben Arts
	Jerry Cox		Ken Sweigart	

Monday	Tuesday	Wednesday	Thursday
April 30th 2012	May 1st 2012	May 2nd 2012	May 3rd 2012
12:00-2:00	9:00-1:00	8:00-12:00	8:00-12:00
2 hrs.	4 hrs	4 hrs.	4 hrs.
CR 701	CR 701	CR 701	CR 702
Job Stage Notebook	Gas Meter Equipment Inventory, Retire Gas Meter Equip, Tracking Gas Meter Equip.	Gas Jobs by Engineers	Gas Service Mobile Order
Attendees:	**Attendees:**	**Attendees:**	**Attendees:**
Facilitator: Teresa Damon	Facilitator: Janna Leaf	Facilitator: Jody Morehouse	Facilitator: Jody Morehouse
Recorder	Recorder	Recorder	Recorder
Scribe	Scribe	Scribe	Scribe
Steve Aubuchon	Steve Williams	Jeff Webb	Jeff Potter
Frank Binder/Steve Plewman	David Howell	David Smith	Mike Littrel
Patti Horobiowski	Judy Olson	Liz St. Mark	Garth Brandon
Ted Boyle		Sonia Johnson	Mike McAllister
Judy Olson			Reuben Arts
Lamont Miles			

APPENDIX J: Current State Mapping Schedule Continued

Week 14

Current State Mapping Week 14

Monday	Tuesday	Wednesday	Thursday	Friday
	May 8th 2012	May 9th 2012	May 10th 2012	May 11th 2012
	1:00-4:30	9:30-3:30	8:30-12:00	10:00-4:00
	3.5 hrs	6 hrs	3.5 hrs	6 hrs.
	CR 702	CR 701	CR 702	CR 702
	Transportation	Tree Trimming/Invoice from Contractors	Edits (Payroll, Transportation, A/P)	Regulator Stations, Farm Tap and Odorizer Inspections
	Attendees:	**Attendees:**	**Attendees:**	**Attendees:**
	Facilitator: Catherine Mueller	Facilitator: Teresa Damon	Facilitator: Catherine Mueller	Facilitator: Kevin Farrington
	Recorder	Recorder	Recorder	Recorder
	Scribe	Scribe	Scribe	Scribe
	Howard Grimsrud	Eric Rosentrater/Larry Lee/Plewman	Howard Grimsrud	Sonia Johnson
	Sue Mullerleile	Julie Lee/Vicki Tallman/Miles	Sue Mullerleile	Candace Baker
	Tami Judge	Raven Perry/Paul Good	Tami Judge	David Howell
	Karen Doran	Ted Boyle/Steve Aubuchon	Karen Doran	
	Linda Fleming	Frank Binder/Patti Horobiowski	Linda Fleming	
		John Hanna/Pam Luders/Michelle Heskett		

May 8th 2012	May 9th 2012	May 10th 2012
9:00-1:00	12:00-3:00	12:30-4:00
4 hrs.	3 hrs.	3.5 hrs.
CR 701	CR 145	CR 701
Gas Meter Testing - New Meters, Manual Results, Test Board and 3rd Party Results	Budget Approval Process	Meter Reading Skip Reads, Prep Table, Code Table, Mark Sense Reads
Attendees:	**Attendees:**	**Attendees:**
Facilitator: Janna Leaf	Facilitator: Bob Weisbeck	Facilitator: Janna Leaf
Recorder	Recorder	Recorder
Scribe	Scribe	Scribe
Steve Williams	Andy Vickers	Jackie Foss
David Howell	Jerry Cox	Robin Hunter
Judy Olson	Alan Lackner	Allyn Smith
	Andrew Marlowe	

May 9th 2012
8:30-12:30
4 hrs.
CR 702
OMT Meter Ping Tool
Attendees:
Facilitator: Jody Morehouse
Recorder
Scribe
Jeff Potter
Mike Littrel
Garth Brandon
Reuben Arts
Mike McAllister

APPENDIX J: Current State Mapping Schedule Continued

Week 15

Current State Mapping Week 15

Monday	Tuesday	Wednesday	Thursday	Friday
	May 15th 2012	May 16th 2012	May 17th 2012	May 18th 2012
	10:00-3:00	8:00-12:00	8:30-12:00	9:00-12:30
	Duration	4 hrs.	3.5 hrs	3.5 hrs
	CR 701	CR 702	CR 702	CR 702
	Closing Job	Pipeline Markers	FA & Depriciation	Projects Accounting - PA (system generated journal)
	Attendees:	**Attendees:**	**Attendees:**	**Attendees:**
	Facilitator: Teresa Damon	Facilitator: Jody Morehouse	Facilitator: Catherine Mueller	Facilitator: Catherine Mueller
	Recorder	Recorder	Recorder	Recorder
	Scribe	Scribe	Scribe	Scribe
	Steve Plewman	Mike Faulkenberry	Kellee Quick	Tami Judge
	Paul Good	Erika Jacobs	Tami Judge	Karen Doran
	Lamont Miles	Liz St. Mark	Karen Doran	Howard Grimsrud
	Michelle Heskett		Howard Grimsrud	Sue Mullerleile
			Sue Mullerleile	

Monday	Tuesday	Wednesday	Thursday	Friday
	May 15th 2012	May 16th 2012	May 17th 2012	May 18th 2012
	9:00-12:00	12:30-4:00	9:00-1:00	1:00-4:00
	3 hrs.	3.5 hrs.	4 hrs	3 hrs.
	CR 145	CR 701	CR 701	CR 702
	Material Procurement	Street Light Setup and Billing	Gas Rotary and Turbine Meter Testing, Tracking Correctors and Telemetry Equipment	Regulator Stations, Electronic Instrument Inspections
	Attendees:	**Attendees:**	**Attendees:**	**Attendees:**
	Facilitator: Bob Weisbeck	Facilitator: Janna Leaf	Facilitator: Janna Leaf	Facilitator: Kevin Farrington
	Recorder	Recorder	Recorder	Recorder
	Scribe	Scribe	Scribe	Scribe
	Andy Vickers	Karen Cornwell	Steve Williams	David Howell
	Steve Wenke	Teresa Damon	David Howell	Sonia Johnson
	John Hamill	Gayle Gonser	Judy Olson	Candace Baker
	Karen Terpak	Mollie Weis		Steve Williams
	Randy Pierce	Bart Janson		
	Greg Lancaster/Ron Gray			

Monday	Tuesday
	May 15th 2012
	1:00-5:00
	4 hrs.
	CR 702
	OMT Transformer Loading Tool
	Attendees:
	Facilitator: Jody Morehouse
	Recorder
	Scribe
	Mike Littrel
	Garth Brandon
	Reuben Arts
	Mike McAllister
	Jeff Potter

APPENDIX J: Current State Mapping Schedule Continued

Week 16

Current State Mapping Week 16

Monday	Tuesday	Wednesday	Thursday	Friday
	May 22nd 2012	May 23rd 2012	May 24th 2012	May 25th 2012
	9:00-1:00	1:00-5:00	1:00-5:00	9:00-12:00
	4 hrs.	4 hrs.	4 hrs.	3 hrs.
	CR 702	CR 702	CR 702	CR 145
	Process	OMT Gas Trouble Current State	SCADA Gas Alarms	Design Reivew Process
	Attendees:	**Attendees:**	**Attendees:**	**Attendees:**
	Facilitator: Janna Leaf	Facilitator: Jody Morehouse	Facilitator: Jody Morehouse	Facilitator: Bob Weisbeck
	Recorder	Recorder	Recorder	Recorder
	Scribe	Scribe	Scribe	Scribe
	Steve Williams	Mike Littrel	Jeff Potter	Steve Wenke
	David Howell	Jeff Potter	Reuben Arts	Mike Gonnella
	Sonia Johnson	Garth Brandon	Mike Littrel	John Hamill
	Jenny Bushnell	Reuben Arts	Garth Brandon	Glen Farmer
		Mike McAllister	Mike McAllister	Mary Jensen/Kristina Newhouse
				Brian Vandenberg/Jeremy Winkle
				May 25th 2012
				10:00-3:00
				5 hrs.
				CR 702
				Regulator Stations, Relief Capacity Review, Unscheduled Reg Station or meterset work
				Attendees:
				Facilitator: Kevin Farrington
				Recorder
				Scribe
				David Howell
				Jenny Bushnell
				Sonia Johnson

Week 17

Current State Mapping Week 17

Monday	Tuesday	Wednesday	Thursday	Friday
	May 29th 2012		May 31st 2012	
	8:00-12:00		1:00-4:00	
	4 hrs.		3 hrs.	
	CR 702		CR 145	
	Valve Maintenance		Project Management	
	Attendees:		**Attendees:**	
	Facilitator: Kevin Farrington		Facilitator: Bob Weisbeck	
	Recorder		Recorder	
	Scribe		Scribe	
	Sonia Johnson		Tim Carlberg	
	Jenny Bushnell		Steve Wenke	
	Condace Baker		Andy Vickers	
	David Howell		Mike Gonnella	
	Liz St. Mark		John Hamill/Cody Krogh	
	Mike Littrel		Glen Farmer/Ron Hargrave	

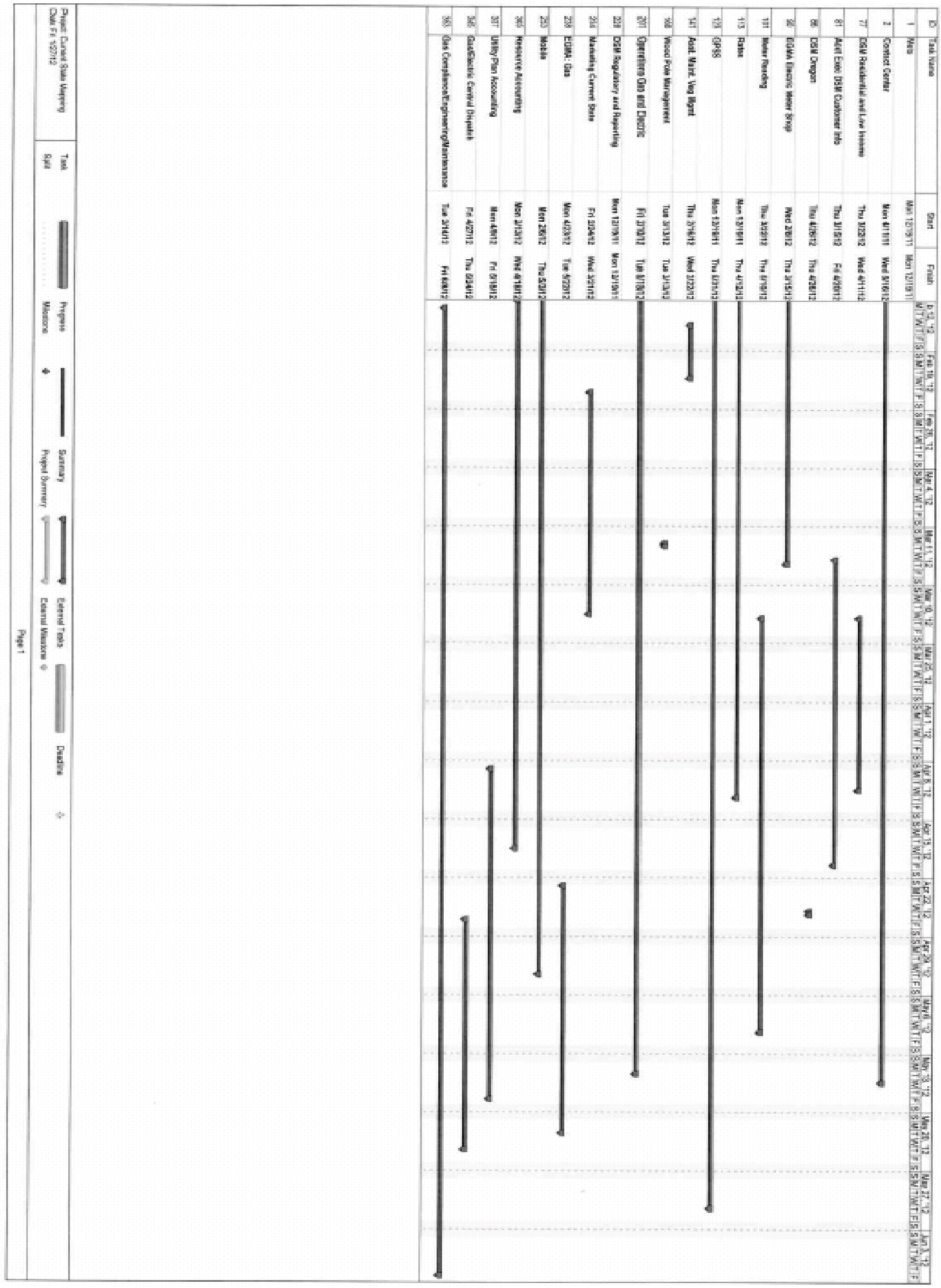
APPENDIX J: Current State Mapping Schedule Continued

Week 18

Current State Mapping Week 18

Monday	Tuesday	Wednesday	Thursday	Friday
	June 5th 2012		June 7th 2012	June 8th 2012
	8:00-12:00		1:00-4:30	9:30-12:00
	4 hrs.		3.5 hrs.	2.5 hrs
	CR 702		CR 702	CR 12 - Dollar Road
	Valve Maintenance		Obsolete Manufacturer and Part Number	Health Check Monitoring
	Attendees:		**Attendees:**	**Attendees:**
	Facilitator: Kevin Farrington		Facilitator: Kevin Farrington	Facilitator: Kevin Farrington
	Recorder		Recorder	Recorder
	Scribe		Scribe	Scribe
	Sonia Johnson		David Howell	Sonia Johnson
	Jenny Bushnell		Linda Burger	Jenny Bushnell
	Condace Baker		Robin Burchett	Candace Baker
	David Howell		Dan Wisdom	David Howell
	Liz St. Mark			
	Mike Littrel			

Appendix K: Current State Mapping Gantt Schedule



Appendix L: Current State Mapping Resources by Business Area

Contact Center: Customer Care
Facilitator: DJ Kinservik
SMEs:

Nancy Upham	Charmaine Heidt
Amber Solverson	Gayle Gonser
Jan Cassis	Renee Webb
Tamara Carter	Janna Leaf
Teresa Damon	Stacie Friend
Debi Neumeier	Deb Noah
Missy Gores	Rachelle Humphrey
Betsy Townsend	Teresa Reimer

Treasury and Finance
Facilitator: Tami Judge
SMEs:

	Gina Armstrong
Karen Doran	Gayle Gonser
Tami Judge	Angie Hayne
Mollie Weis	Denise Burns
Rick Lloyd	Ian McLelland
Cameron Dunlop	Carolyn Groome
Maureen Olsen	Jeannie Schmidt
Cindy Healy	Gudu Fischer
Monica Bannon	Catherine Bowden
Kym Stiles-Lewis	Amanda Gehrig
Amanda Reinhardt	Eric Bowles
Janna Leaf	Sue Senescall
Adam Munson	Laura Brittain

Utility Plant Accounting
Facilitator: Tami Judge
SMEs:

Catherine Mueller	Sue Mullerleile
Howard Grimsrud	Karen Doran

Gas Compliance, Gas Programs, Gas Eng.
Facilitator: Jody Morehouse & Kevin Farrington
SMEs:

Pam Horney	Shawn Gallagher
Sonia Johnson	Virginia Omoto
Jenny Bushnell	Rob Cloward
Kevin Farrington	Linda Burger
Jeff Webb	David Smith
Steve Williams	Mike Littrel
Erika Jacobs	Liz St. Mark
David Howell	Dan Wisdom
Erika Jacobs	Mike Faulkenberry
Gary Douglas	Katy Cordrey

DSM Regulatory and Reporting
Facilitator: DJ Kinservik
SMEs:

Mark Baker	Greta Zink
Lorri Kirstein	

EMT (METS)
Facilitator: Mike Magruder
SMEs:

Rodney Pickett	Eric Meier
Glen Madden	Darrell Soyars
Liz St Mark	Bryce Robbert
Ernie Lugan	Mike Dahl

Commercial DSM/Account Management
Facilitator: DJ Kinservik
SMEs:

Ann Carey	Kerry Shroy
Sue Baldwin	Lorri Kirstein
Catherine Bryan	Kelly Conley
Camilee Martin	Greta Zink
Tom Leinhard	Renee Coelho

DSM Oregon
Facilitator: DJ Kinservik
SMEs:
Lisa McGarity
Kerry Shroy

Contact Center: Credit and Collections
Facilitator: Renee Webb
SMEs:

Kym Stiles	Patty Batters
Deb Noah	Nancy Upham
Amanda Reinhardt	Jackie Foss
Heather Acord	Sarah Sather
Jennifer Willis	Teresa Reimer
Tamara Carter	

Rates
Facilitator: Ken Humphries
SMEs:

Ken Humphries	Jen Smith
Shawn Bonfield	Joe Miller
Tara Knox	

Gas Meter Shop
Facilitator: Janna Leaf
SMEs:

Steve Williams	Sonia Johnson
David Howell	Mollie Weis
Dan Whicker	Judy Olson
Mike Littrel	

Electric and Gas Operations
Facilitator: Teresa Damon
SMEs:

Paul Good	Jeannie Schmidt
Charmaine Heidt	Vicki Tallman
Steve Aubuchon	Shelia Ward
Ted Boyle	Patti Horobiowski
Scott Phipps	Connie Gorman
Leslie Suprgeon	Frank Binder
Sheryl Florance	Mike Littrel
Genne Lehti	Carrie Mourin
Pam Luders	Karen Cornwell
David Scalido	Nancy Carroll
Vicki Vinson	Larry Lee
Raven Perry	John Hanna
Shane Pacini	Judy Olson
Deb Denney	Kelly Donohue
Eric Rosentrater	Maria Sullivan
Mark Porier	

DSM Residential & Low Income
Facilitator: DJ Kinservik
SMEs:

Rachelle Humphrey	Kathy Carpenter
Kerry Shroy	Kristine Meyer
Ann Carey	Stacie Friend
Renee Coelho	Chris Drake
Renesha Conley	Roxanne Williams

Substation Inspections (METS)
Facilitator: Mike Magruder
SMEs:

Rodney Pickett	Eric Meier
Glen Madden	Darrell Soyars
Liz St Mark	Bryce Robbert
Ernie Lugan	Mike Dahl

Marketing
Facilitator: DJ Kinservik
SMEs:

Kelly Conley	Scott Phipps
Mary Broemeling	Tom Heavey
Mary Tyrie	Colette Bottinelli
Scott Steele	Dana Anderson

Meter Reading
Facilitator: Janna Leaf
SMEs:
Jackie Foss
Allyn Smith
Robin Hunter

Contact Center: Billing and Bill Printing
Facilitator: Janna Leaf
SMEs:

Maureen Olson	Karen Cornwell
Galen Lorenz	Heather Acord
Darrin Belgarde	DJ Kinservik
Sandy Honn	Teresa Reimer
Mollie Weis	

Electric Meter Shop
Facilitator: Janna Leaf
SMEs:

Greg Paulson	Mollie Weis
Judy Olson	Robert Dodd
Bob Hooper	Shana Gail
Sarah Sather	Mark Poirier

Asset Maint: Vegetation Management
Facilitator: Amber Gifford
SMEs:

Pam Luders	Larry Lee
Steve Schwartz	Rob Wagner
Derek Babcock	Rob Cloward
Michelle Muck	Chris Richardson
Kipp Dennis	Iban Lucera

Asset Maint: Wood Pole Maintenance
Facilitator: Amber Gifford
SMEs:

Glenn Madden	Mark Gabert
Amber Fowler	Ivan Rounds
Valerie Petty	Gary Knight
Amber Gifford	Howard Grimsrud
Dan Gregovich	Janine Seibel
Cherie Hirschberger	

Central Dispatch
Facilitator: Jody Morehouse
SMEs:

Jeff Potter	Mike McAllister
Mike Littrel	Reuben Arts
Garth Brandon	

PCB Testing and Tracking
Facilitator: Amber Gifford
SMEs:

Rodney Pickett	Eric Meier
Glen Madden	Darrell Soyars
Liz St Mark	Bryce Robbert
Ernie Lugan	Mike Dahl

Distribution Transformers (METS)
Facilitator: Amber Gifford
SMEs:

Rodney Pickett	Eric Meier
Glen Madden	Darrell Soyars
Liz St Mark	Bryce Robbert
Ernie Lugan	Mike Dahl

Generation and Production
Facilitator: Bob Weisbeck
SMEs:

Andy Vickers	Dean Hull
Jerry Cox	Gregory Wiggins
Kelly Magalsky	Debbie Biggs
Deb Mortlock	Ryan Bean
Ken Sweigart	Eric Atkinson
Ron Hargrave	Glen Farmer
Tom Zimmerer	Tammie Miller
Randy Pierce	Greg Lancaster
Andrea Marlowe	Brian Vandenberg
Lin Miller	Cody Krogh
Steve Wenke	Mike Gonnella
Alan Lackner	John Hamill
Karen Terpak	Mary Jenson
Adam Newhouse	Jason Graham
Aaron Henson	

Attachment 11

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Scoring results of the assessments of vendor's solution and services proposals, per Attachment 8

Pages 1 through 62

Attachment 12

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Final solution evaluation workbook, per Attachment 8

Pages 1 through 15

Attachment 13

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Voting tallies for final vendor Selections

Pages 1 through 2

Attachment 14

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Price comparison of final solutions packages

Pages 1 of 1

Attachment 15

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Final capital budget approved for Project Compass.

Pages 1 of 1

Attachment 16

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Project update for Avista's Board of Directors, February 2012.

Pages 1 through 13

Attachment 17

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Project update for Avista's Board of Directors, September 2012

Pages 1 through 10

Attachment 18

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

LARRY D. LA BOLLE
Exhibit No. 502

Aldyl A Natural Gas Pipe Replacement and Project Compass

CONFIDENTIAL

Project update for Avista's Board of Directors, February 2013

Pages 1 through 11

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF ELIZABETH M. ANDREWS
REPRESENTING AVISTA CORPORATION

Revenue Requirement and Allocations

I. 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[1] 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. As the Manager of Revenue Requirements, what are your responsibilities?

A. As Manager of Revenue Requirements, aside from special projects, I am responsible for the preparation of normalized revenue requirement, pro forma studies, and forecasted studies for the various jurisdictions in which the Company provides utility services. Since 2000 I have assisted or led the Company's electric and/or natural gas general rate filings in Washington, Idaho and Oregon.

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

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 forecasted operating results including expense and rate base adjustments made to actual operating results and rate base.

The forecasted net operating income and rate base that serve as the basis for the overall revenue requirement in this filing incorporate not only those adjustments prepared by myself, but also by Company witnesses Mr. DeFelice and Mr. Ehrbar. I will cover the revenue adjustment briefly, while Mr. Ehrbar provides a more in-depth discussion. I will provide a summary of the Company’s restated 2012 net plant, forecasted 2013 and 2014 capital additions and recently approved depreciation study adjustments, while Mr. DeFelice will present more detail for each of these adjustments in his testimony. I also briefly discuss the Company’s expected need for rate relief that will occur beyond the 2014 rate period requested in this proceeding for informational purposes only. Finally, I will provide an overview of the Company’s system and jurisdictional allocation methodologies that have been in place for several years.

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

A. Yes. I am sponsoring Exhibit Nos. 601-603, which were prepared under my direction. Exhibit No. 601 consists of worksheets, which show summary level historical actual 2012 operating results, forecasted results for 2014 including proposed natural gas operating results and rate base for the Company’s Oregon jurisdiction, the Company’s calculation of the general revenue requirement, the derivation of the net operating income to gross revenue conversion factor, and the restating and forecasted adjustments proposed in this filing. Exhibit No. 602 consists of worksheets similar to Exhibit No. 601 on a detail (by FERC account) level. Exhibit No. 603 provides the Company's Allocation Processes and Methodologies presentation material discussed later in my testimony.

II. REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

Q. Would you please summarize the results of the Company's forecasted study for its natural gas operating system for the Oregon jurisdiction?

A. Yes. After taking into account all historical restating, forecasted and restated forecasted (previous Commission–ordered restating) adjustments, the forecasted natural gas rate of return ("ROR") for the Company's Oregon jurisdictional operations is 4.69%, as shown on Exhibit No. 601, page 1. This return level is below the Company's requested rate of return of 7.83%. The incremental revenue requirement for base retail rates, necessary to give the Company an opportunity to earn its requested ROR, is $9,481,000. The overall base natural gas revenue increase associated with the Company's request is 9.5%.

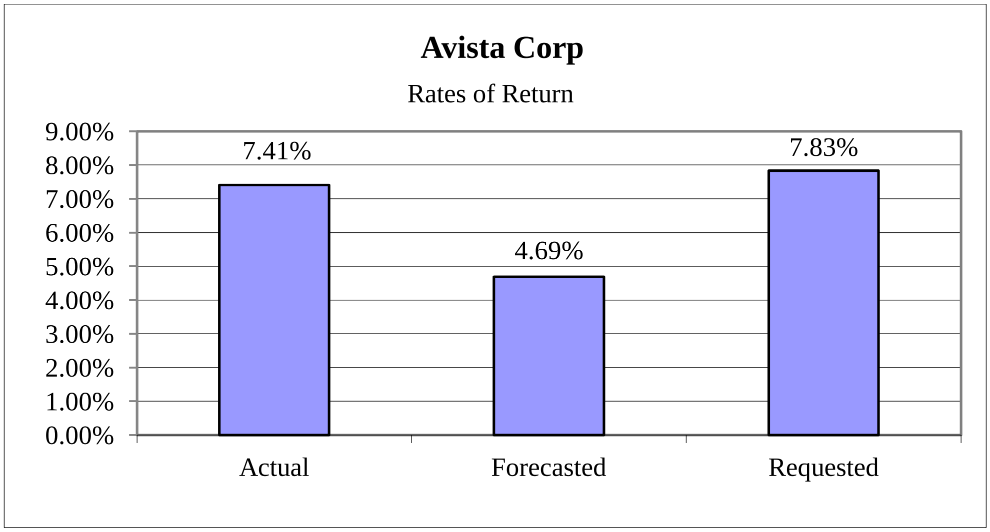
Q. What was the Company's rate of return that was last authorized by this Commission for its natural gas operations in Oregon?

A. The Company's currently authorized rate of return for its Oregon operations is 8.00%, effective March 15, 2011.

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

A. Yes. As shown in Illustration No.1 below, there are three different rates of return that will be discussed. The actual ROR earned by the Company during the twelve months ended December 31, 2012, the forecasted ROR determined in my Exhibit No. 601, page 1, and the requested ROR.

Illustration No. 1:



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

A. The forecasted test period being used by the Company is the twelve months ended December 31, 2014, presented on a forecasted basis. Currently authorized rates are based upon the 2011 forecasted test year utilized in Docket No. UG-201 adjusted on a pro forma basis.

Q. Why did the Company use the year ending December 31, 2014 as the test period?

A. The forecasted test period in this case was selected to best reflect the conditions during which time the new rates will be in effect. Rates from this proceeding are expected to be effective on or before mid-2014. Although the use of the 2014 calendar-year rate period will likely understate the costs the Company will incur to serve customers during the time new rates will be in effect, it provides a reasonable basis for the calculation of revenue requirement in this case.

Q. Please explain how the Company developed the revenue requirement for the 2014 test period.

A. Revenue requirement preparation began with the historical accounting information for the twelve months ended December 31, 2012. Each of the revenue requirement components in the historical period was analyzed to determine if a normalizing or correcting adjustment was warranted to reflect normal operating conditions. The restated historical information was then adjusted to recognize known, measurable and anticipated events to determine a forecasted 2014 test period. Next, the forecasted test period results were adjusted to include previous Commission–ordered restating adjustments, resulting in Restated Forecasted 2014 test period results.

Q. Why did the Company begin with historical information?

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

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

A. Revenues are adjusted for the effect of applying the current Commission-approved tariff rates to the forecasted test period customer usage. Historical operations and maintenance ("O&M") expenses were separated into labor and non-labor components. Except for a few specific cost items, non-labor costs were adjusted using the consumer price index (CPI). Historical labor costs were also adjusted for increases through the end of the forecasted test period. Specific adjustments are described in further detail later in my testimony and shown in Exhibit Nos. 601 and 602.

III. NEED FOR ADDITIONAL RATE RELIEF

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

A. Over 92% (or approximately $8.75 million) of the Company's need for additional rate relief relates to increases in Total Rate Base, including changes in Net Plant Investment (including return on investment, depreciation and taxes, offset by the tax benefit of interest), representing an increase of approximately $36.9 million additional net rate base for the Oregon jurisdiction. The remaining 8% (or approximately $730,000) of the Company's requested revenue requirement relates to a three-year net increase in Operating and Maintenance (O&M) and Administrative and General (A&G) expenditures since our last rate case filed in 2010.

Q. What are the major components of the changes to Total Rate Base included in the Company's filing?

A. Looking at the changes to "gross" plant in service, Oregon "gross" plant increased by approximately $47.7 million, or 18%, as compared to what is currently included in rates. These investments reflect replacement and maintenance of Avista's aging system, and to sustain reliability and safety. Major projects included in this total include the Company's Customer Information System and Aldyl A pipe replacement projects described by Company witness Mr. La Bolle, as well as other 2014 required projects, as more fully described by Company witness Mr. DeFelice. After adjusting for accumulated depreciation and amortization, and accumulated deferred income taxes, the net rate base increase is $27.0

million. (After including return on investment, depreciation and taxes, offset by the tax benefit of interest, this amounts to approximately $7.6 million of the requested revenue requirement.)

Also increasing the Company's net rate base, are working capital and prepaid pension asset adjustments, of approximately $6.3 million and $3.7 million, respectively. These adjustments described further below, increased the Company's requested revenue requirement by approximately $733,000 (see Working Capital Adjustment) and $428,000 (see Forecast Labor and Benefits Adjustment), respectively.

IV. GENERAL REVENUE REQUIREMENT

Q. Would you please explain what is shown in Exhibit No. 601?

A. Yes. Exhibit No. 601 shows 2012 actual results and forecasted natural gas operating results and rate base for the 2014 test period for the Company's Oregon jurisdiction. Column (a) of page 1 of Exhibit No. 601 shows the twelve months ended December 31, 2012 operating results and components of rate base as recorded; column (b) is the total of all adjustments to net operating income and rate base; and column (c) is forecasted results of operations, all under existing rates. Column (d) shows the revenue increase required which would allow the Company an opportunity to earn its requested 7.83% rate of return. Column (e) reflects forecasted natural gas operating results with the requested general increase of $9,481,000.

Q. Would you please explain page 2 of Exhibit No. 601?

A. Yes. As discussed earlier in my testimony, page 2 shows the calculation of the $9,481,000 revenue requirement using the requested 7.83% rate of return.

Q. Would you now please explain page 3 of Exhibit No. 601?

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 10 of your Exhibit No. 601, would you please explain what those pages show?

A. Yes. Page 4 begins with actual operating results and rate base for the twelve months ended December 31, 2012 in column (1.00). Individual historical Restating Adjustments start on page 4, column (1.01), and continue through page 5, column (1.05), resulting in the column labeled "Restated Historical 2012 AMA Test Period Total." Individual Forecast Adjustments start on page 6, column (2.00), and continue through page 8, column (2.10), resulting in the column labeled "Forecasted 2014 AMA ROO Total." Finally, individual Forecasted Restating Adjustments, representing previous Commission–ordered and/or standard components of our annual earnings reporting to the Commission, applied to the 2014 Forecasted results, begin at page 9, column (3.00), and continue through page 10, column (3.05). The final column, which is a subtotal of all preceding columns of adjustments, results in the column labeled "Restated 2014 AMA Forecasted Test Period." Exhibit No. 602 provides similar data as Exhibit No. 601, pages 1, and 4 through 10, at a detail level by FERC account. Descriptions of each adjustment noted above and included on pages 4 through 10 of Exhibit No. 601 are described more fully below, and supporting workpapers for each of these adjustments accompany the Company's filed case.

V. HISTORICAL RESTATING ADJUSTMENTS

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

A. Yes. The first adjustment, column (1.01) on page 4, **Allocation Factor Adjustment,** restates actual 2012 test period Oregon Results of Operations allocated expense accounts using updated allocation factors. During 2012 costs to be allocated were allocated based on the allocation factors in effect as of January 1, 2012 through December 31, 2012. These factors were based on actual direct 2011 costs. The Company updates its allocation factors annually using the prior year's actual direct costs using the methodology approved by the Commissions. When the factors are updated annually, the factors are reviewed to identify any unusual trends or unexpected shifts in costs. Effective January 1, 2013, and utilized in this filing, are the most current allocations based on 2012 actual direct costs. For further discussion of the Companies allocation processes and methodologies, please see Section IX. Cost Assignment and Allocation Procedures below. This adjustment decreases Oregon net operating income by $117,000.

Column (1.02), **Miscellaneous Restating,** restates actual test period results for miscellaneous restating items such as advertising, removal of non-utility related items, and reclassification of items to their appropriate service and jurisdiction. The adjustment for advertising is comprised of two components: 1) Restates the 2012 test period advertising expense for corrected jurisdictional allocation of expenses, and 2) removes costs reflecting the application of 1/8 of 1% of proposed retail revenues, pursuant to OAR 860-026-0022. This adjustment increases Oregon net operating income by $2,000.

The adjustment in column (1.03), **Eliminate Adder Schedules**, removes both the revenues and expenses associated with all adder schedule rates except current gas costs. The items eliminated include: Schedule 460 – Excess Franchise Tax, pass through of franchise taxes in excess of 3% charged only to customers in the various municipalities; Schedule 408 – Senate Bill 408, the final 5 months of the final rebate occurred during 2012 and is eliminated as well as deferrals associated with interest on the unamortized balance; Schedule 493 – LIRAP pass through collection; Schedule 478 – DSM surcharge and amortization; Schedule 499 – Medford Deferred Capital surcharge and amortization; Schedule 476 – Intervenor Funding surcharge and amortization; Schedule 477 – Commission Fees eliminates prior period adjustment to amortization completed in 2011; Schedule 496 – Margin Reduction surcharge and amortization; and Schedule 462 – Prior Gas Cost refund and amortization. The revenue and expense impact of this portion of the adjustment nets close to zero[2] and facilitates analysis of cost of service and rate design for base rates. This adjustment also removes the 2012 deferral entries for the Medford Capital projects and DSM Lost Margin revenue that are inappropriate to include in the base for 2014 rates. The total adjustment decreases net operating income by $221,000.

The adjustment in column (1.04), **Weather Normalization Sales/Purchases**, normalizes weather sensitive gas therm sales by eliminating the effect of temperature deviations above or below historical normals. This adjustment restates revenue and gas cost to reflect the change in therm sales if weather had been normal based upon energy rates and the authorized weighted average cost of gas in effect during the year. The adjustment reflects

[2] The result is not exactly zero due to the timing of the gross revenue factors used to create the adder rates being slightly different from the 2012 Commission Basis revenue conversion expense factors applied to the revenue elimination.

a winter season consisting of October through June and historical normals computed on a twenty-five year rolling average per the settlement in Docket No. UG-181 (Order No. 08-185). This adjustment also identifies and consolidates all of the 2012 purchased gas cost related accounts into the "Gas Purchases" line item in order to simplify the forecast revenue load adjustment. The impact of the weather normalization adjustment is a decrease to Oregon net operating income of $95,000.

Starting on page 5, column (1.05), entitled **Restate Debt Interest**, restates debt interest using the Company's forecasted weighted average cost of debt, as outlined in the testimony and exhibits of Company witness Mr. Thies. This adjustment restates debt interest on the Results of Operations level of rate base shown in column (1.00) only, resulting in a revised level of tax deductible interest expense on actual historical test period rate base. The federal income tax effect of the restated level of interest for the historical test period reduces Oregon net operating income by $96,000.

The Federal income tax effect of the restated level of interest on all other rate base adjustments included in the Company's filing are included and shown as an income impact of each individual rate base adjustment described elsewhere in this testimony.

Q. Before describing the final column on page 5 of Exhibit No. 601, are there any other regulatory asset balances included in the Company's restated historical 2012 AMA test period needing mention here?

A. Yes. Other regulatory assets included in the Company's 2012 AMA historical test period, and shown on page 4 of Exhibit No. 601, Column (1.00) titled "Per Results of Operations Report," line 243 titled "Total Gas Inventory," is the Company's natural gas inventory balance of $3.084 million. This balance relates to the Company's combined one-third ownership share and leased storage of the Jackson Prairie underground storage facility, a portion of which is allocated for the benefit of Oregon customers. Company witness Mr. Harper describes in more detail Avista's ownership and use of this facility.

Since the inclusion of this asset in Oregon operations, the Company has rate based Oregon's share of its Jackson Prairie inventory recorded in FERC Account 164, receiving a return on this rate based item at the approved rate of return as a component of the revenue requirement recovered from Oregon customers. In addition, the revised accounting treatment of Avista's inventory was reviewed and approved in Order No. 11-080 in Docket No. UG-201, as the Company had requested revised accounting treatment for its stored natural gas, moving existing cushion gas from non-recoverable (FERC Account No. 352.3), which is a depreciable asset, to recoverable (FERC Account No. 117.1), which is a non-depreciable asset.

Consistent with Docket No. UG-201, Avista has included in net rate base the AMA 2012 balance of $3.084 million included in "Total Gas Inventory," which includes Oregon's balances in FERC Accounts 117 – Gas Stored – Recoverable Base Gas and 164 – Gas Inventory – Jackson Prairie.[3] Rate base treatment of natural gas inventory is consistently applied within Avista's Idaho and Washington natural gas jurisdictions, as well as by its peer utilities serving customers in the state of Oregon.

Q. Please continue with your description of the final column on page 5 of Exhibit No. 601.

A. The final column entitled Restated Historical 2012 AMA Test Period Total,

[3] Inventory has been excluded from the Company's working capital adjustment calculation described later in my testimony, as separate rate base treatment has been the consistent historical approach approved for recovery of the return on the Company's inventory balance.

provides a subtotal of the preceding columns (1.00) through column (1.05) and represents actual operating results and rate base, plus the restating adjustments that have been previously discussed.

VI. FORECASTED ADJUSTMENTS

Q. Please explain the significance of the eleven columns that begin on page 6 and continue through page 8, in your Exhibit No. 601.

A. The eleven adjustments, subsequent to the Restated Historical 2012 AMA Test Period Total column, represent forecasted adjustments that recognize the jurisdictional impacts of items that will affect the forecasted operating period levels. They encompass revenue and expense items as well as additional capital projects and rate base items. These adjustments bring the 2012 operating results and rate base to the forecasted level for the 2014 forecasted test period.

Q. Please explain the first adjustment on page 6.

A. Column (2.00), **Forecast Expense Adjustment**, increases non-labor O&M and A&G expenses based on forecasts through 2014 for various FERC accounts. Workpapers accompanying my testimony and exhibits in this case provide the adjustments by FERC account, provides the Company's analysis of each adjusted FERC account balance and shows the use of CPI of 2.1% year over year for 2013 and 2014. This adjustment decreases Oregon net operating income by $231,000.

Column (2.01), **Forecast Revenue Load Adjustment**, takes into account forecasted normalized usage and customers during 2014. It calculates revenues and purchased gas expense based on rates and associated gas costs approved in the Company's most recent Purchased Gas Adjustment effective November 1, 2012. This adjustment was made under the direction of Mr. Ehrbar and is described further in his testimony. The effect of this adjustment is to increase Oregon net operating income by $684,000.

Column (2.02), **Forecast Labor and Benefits Adjustment**, reflects changes to the historical period labor and benefits for union and non-union forward to 2014 levels. Historical period labor and benefits for 2012, excluding the impact of the Voluntary Severance Incentive Plan (VSIP) described further below, were restated to annualize the March 1, 2012 increase, include the 2013 increase, and to include the 2014 increase as of March 1, 2014. Executive labor was adjusted to current 2013 level salaries only.

This adjustment also includes the net changes in both the Company's pension and medical insurance expense expected for 2014. These changes reflect a decrease in pension costs primarily due to changes in actuarial assumptions related to a reduction in the discount rate offset by additional contributions of $44 million each year planned for 2013 and 2014, whereas medical insurance is increasing primarily due to our most recent medical trend analysis, which forecasts claim activity will outpace the current level of expense. The total decrease in Oregon net operating income resulting from these adjustments is $182,000.

In addition to the labor and benefits expense increase, the Company is also including an adjustment to increase regulatory assets by $5,710,000 and Accumulated Deferred Federal Income Taxes (ADFIT) by $2,000,000, resulting in a net rate base increase of $3,710,000 related to Oregon's share of the Company's prepaid pension asset currently residing on its books.

Q. Has the Company previously requested to rate base its prepaid pension asset in its Oregon jurisdiction?

A. No, we have not. The Company has previously requested recovery of

Oregon's share of its forecasted pension cost planned during the rate year based on its Actuarial derived Financial Accounting Standard (FAS) 87 expense amount. However, in November 2012, the Oregon Commission opened an investigation into the treatment of pension costs in utility rates. Through this open docket, Docket No. UM 1633, the question of how pension costs should be recovered, whether it is appropriate for Utilities to fully recover their costs associated with their pension plans by earning a return on a prepaid pension asset, and how that prepaid pension asset balance will be valued, is being investigated.

The merits of a policy change related to recovery of pension costs and the appropriateness of including a return on prepaid pension assets will be fully vetted during the process of UM 1633, and therefore will not be included in detail here. However, for Avista a prepaid pension asset exists on its books today, resulting from cumulative contributions in excess of cumulative FAS 87 expense, resulting in additional financing costs to the Utility. This condition is expected to reverse in the future, with pension expense overtaking contributions and reducing the prepaid balance eventually to zero. However, until these excess contributions are fully recovered, the Company is incurring and will continue to incur significant costs to finance its prepaid pension asset. Therefore, the Company believes it is appropriate to rate base such an asset, and be allowed to earn a return on such asset. To exclude a return on the excess cash contributions in rates excludes a portion of costs attributable to providing services to its customers.

The Company recognizes the outcome of UM 1633 may be decided prior to the completion of this case, and therefore has included Oregon's share of the prepaid pension asset existing on its books today within the revenue requirement requested in this case. The calculation of the Company's prepaid pension asset and Oregon's share of that balance is included within my workpapers. If, however, UM 1633 has not concluded before the outcome of this general rate case has been decided, the Company would not be opposed to deferring the associated revenue requirement included in this filing (approximately $428,000) for recovery at a later time to be based on the Commission's decision in UM 1633.

Q. Please continue with your explanation of the forecast adjustments on page 6.

A. Column (2.03), **Forecast VSIP Amortization Adjustment,** includes 1/3 of Oregon's share of the Voluntary Severance Incentive Plan (VSIP) costs incurred by the Company in December 2012. The Company is proposing, for regulatory purposes, to amortize Oregon's share of the VSIP costs over the three-year period 2013-2015, or $183,000 annually.

Q. Could you please explain the Voluntary Severance Incentive Program implemented in December 2012?

A. Yes. In October 2012, Avista's Board of Directors approved the Company's VSIP to reduce the total utility workforce and achieve necessary long-term, sustainable, Company-wide savings.

In general, most regular full and part-time employees of Avista Corp. (not including its subsidiaries) who were not covered by a collective bargaining agreement were eligible to participate in the program. Through this program, effective January 1, 2013, Avista reduced its number of employees by 55, or approximately 6 percent, of the eligible 919 non-union employees. Approximately 50 percent of the applicants to the program were approved for severance by Company management.

As all severences under the voluntary severance incentive program were completed by December 31, 2012, the cost of the program was recognized as expense during the fourth quarter of 2012 and severance pay was distributed in a single lump sum cash payment to each participant during January 2013. Total Company VSIP severance pay, excluding medical and other expenses, under the program were $6.72 million (pre-tax) (Oregon's share totaled approximately $549,000).[4] The long-term operating and maintenance cost savings under the program (approximately $5.4 million annually on a system basis) are expected to exceed the severance costs of the program and the expected payback period for the severance costs will be approximately 1.4 years.

Q. Why is it appropriate for the Company to recover these VSIP costs and amortize these expenses over a three-year period?

A. In the Company's filed case, the total VSIP severance cost of $6.72 million was excluded from the (historical test period) December 31, 2012 Oregon Results of Operations. In addition, total 2012 labor expense for the 55 employees who elected to participate in the VSIP payout, were removed prior to determining the restated 2014 level of labor expenses included in the 2014 rate period results. Through this reduced level of 2014 labor expense, customers are receiving the benefit of the VSIP savings incurred. Therefore, it is entirely appropriate for customers to also pay the costs associated with receiving these savings, properly matching costs and benefits of providing service to those customers. In order to mitigate the impact of Oregon's share of the VSIP costs of $549,000, the Company is proposing a three-year amortization (2013-2015) of $183,000 annually. The effect of this adjustment reduces Oregon net operating income by $110,000.

Q. Please now turn to page 7 and continue with your explanation of the

[4] Total Company VSIP (pre-tax) amount was approximately $7.3 million, including severance pay, Supplemental Security Income (SSI), Medicare, medical premiums and Health Reimbursement Arrangement (HRA) expenses.

forecast adjustments.

A. Column (2.04), **Forecast Property Tax Adjustment**, restates the 2012 historical test period accrued levels of property taxes to the 2014 rate period level using the most current information. Historical test period accrued levels of property taxes included in the Company's 2012 Oregon operating results reflect property taxes accrued based on plant balances as of December 31, 2011. This adjustment estimates the taxes to be paid on plant balances as of December 31, 2012 during 2014, by using the last known value assessments and levy rates, adding plant additions through December 31, 2012, less depreciation, and then applying a small escalator to the levy rates to reflect their general increasing trend. (Increases in property tax planned in 2014 associated with 2013 and 2014 plant additions are reflected within the Capital Activity Adjustments discussed below; see adjustments (2.06) and (2.07)). The effect of this adjustment is to decrease Oregon net operating income by $120,000.

Column (2.05), **2012 Capital Activity Adjustment**, adjusts the 2012 test period rate base (including the associated accumulated depreciation and DFIT) stated on an AMA basis to an end-of-period (EOP) basis. This adjustment also includes the annual level of associated depreciation expense on all plant-in-service at December 31, 2012. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. This adjustment decreases Oregon net operating income by $93,000 and increases rate base by $1,577,000.

Column (2.06), **2013 Capital Activity Adjustment**, reflects all 2013 capital additions together with the associated accumulated depreciation and DFIT at a 2013 EOP basis. This adjustment also includes the annual level of associated depreciation expense and property taxes on the 2013 capital additions. In addition, this adjustment adjusts the 2012 capital projects [included in adjustment (2.05)] together with the associated accumulated depreciation and DFIT to a 2013 EOP basis. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. The impact on Oregon net operating income for this adjustment is a decrease of $488,000, with an increase to rate base of $15,672,000.

Column (2.07), **2014 Capital Activity Adjustment**, reflects 2014 capital additions moved into service by June 30, 2014 together with the associated accumulated depreciation and DFIT to a June 30, 2014 EOP basis.[5] This adjustment also includes the annual level of associated depreciation expense and property taxes on the 2014 capital additions. In addition, this adjustment adjusts the plant that was in service at December 31, 2012 (included in adjustment (2.05)), plus the 2013 capital additions (included in adjustment (2.06)) together with the associated accumulated depreciation and DFIT to a June 30, 2014 EOP basis. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. The impact on Oregon net operating income for this adjustment is a decrease of $425,000, with an increase to rate base of $8,381,000.

Column (2.08), **Depreciation Study Adjustment**, adjusts 2012 and 2013 vintage plant depreciation expense to the 2014 expense level based on new depreciation study rates.

The Company was authorized to change its depreciation rates by the Oregon Commission in Order 13-168, dated May 6, 2013 (Case No. UM 1626) in two phases. The <u>first phase</u> approved <u>common plant</u> (allocated) depreciation rates, including transportation vehicles, to commence with the Company's Washington and Idaho jurisdictions'

[5] The Company has included EOP June 30, 2014 for all plant including the Customer Information System (CIS) project although it has an estimated in-service date of July 2014, at which time 90% of the project is estimated to be complete and will go-live. The remaining 10% is related to post production support expected for 90 days following the go-live date.

implementation on January 1, 2013. The second phase approved implementation of depreciation rates on plant directly assigned to Oregon, to become effective with the effective date of new customer base rates at the conclusion of this general rate case.

This adjustment also adjusts the associated accumulated depreciation and DFIT to reflect the expected 2014 balances on a June 30, 2014 end-of-period basis for the 2012 and 2013 vintage plant in service at December 31, 2013. This adjustment was made under the direction of Mr. DeFelice and is described further in his testimony. The net effect of this adjustment decreases Oregon net operating income by $1,035,000 and decreases rate base by $999,000.

Column (2.09), entitled **Working Capital**, increases total rate base for the Company's working capital adjustment. Cash Working capital represents the funds required to enable the Company to operate its business on a daily basis. The need for these funds results from the fact that there is a lag in time between the collection of revenues for services rendered and the necessary outlay of cash by the Company to pay the expenses of providing those services. Cash working capital represents investor supplied funds that are properly included in the Company's rate base for ratemaking purposes. Application of the overall rate of return to this element of rate base allows the Company to service the capital costs associated with the cash working capital.

Although there are various appropriate methods used to determine a Company's working capital, the Company has calculated its working capital in this proceeding using the Investor Supplied Working Capital (ISWC) method. The Company believes this is a reasonable approach to working capital, representing expended funds to provide reliable service to its customers. The net effect of this adjustment increases Oregon net operating income by $71,000 and increases rate base by $6,355,000.

Column (2.10), entitled **Forecast Insurance**, adjusts actual historical test period insurance expense for general liability, directors and officers ("D&O") liability, and property to reflect the expected 2014 insurance level of expense, resulting in an increase in expense of $76,000 Oregon share. The Company expects to see a significant increase in each of these insurance categories. General liability insurance is expected to increase due to primary insurance policy providers seeking increases due to adverse impacts over the last several years from increased claim history and due to suspension by insurance providers of the continuity credit provided in previous years. Property insurance premiums are being driven up by two primary factors: 1) projected increases in asset values for the Company, and 2) increases in the rate per $100 of coverage of these assets caused by weather related catastrophe losses associated with Super Storm Sandy in 2012, and significant losses related to a few refinery explosions in the industry in 2013. Director's & Officer's (D&O) insurance premiums are also expected to increase, driven by a significant reduction in our continuity credit combined with an increase in premium rates. The net effect of this adjustment decreases Oregon net operating income by $46,000.

The final column entitled **Forecasted 2014 AMA ROO Total**, provides a subtotal of the preceding columns (1.00) through column (2.10) and represents 2014 forecasted operating results and rate base prior to any required restating adjustments described below.

VII. RESTATING FORECASTED ADJUSTMENTS

Q. Please explain the significance of the columns that begin on page 9 and

continue on page 10, in your Exhibit No. 601.

A. The six adjustments subsequent to the Forecasted 2014 AMA ROO column represent restating adjustments to adjust the 2014 forecasted total results for Commission required adjustments. They encompass restating of forecasted expense items as well as rate base items. These adjustments bring the 2014 forecasted operating results and rate base to the 2014 restated forecasted test period.

Starting on page 9, the first adjustment in column (3.00), **Uncollectible Expense**, revises the 2012 historical period level of accrued expense included within the Company's Results of Operations, to the 2012 actual net customer accounts receivable write-offs. Over the last few years, the Company has seen the actual net write-offs as a percent of revenue increase. Although the Company typically restates uncollectible expense, consistent with the Company's' UM 903 Spring Earnings Review filing, using a historical three-year average of actual net write-offs, this adjustment reflects the actual net customer accounts receivable write-offs for 2012. The Company believes the 2012 amount is a reasonable and conservative level of uncollectible expense to be included in this case. The effect on Oregon net operating income is an increase of $43,000.

The adjustment in column (3.01), **Incentive Pay**, adjusts incentive expense by removing 100% of the executive incentive, removing 50% of the non-executive incentive, and removing 50% of merit-based incentives. This is the same method as agreed to in UG 186, Order No. 09-422, dated October 26, 2009. The result of this adjustment is an increase in net operating income of $263,000.

Column (3.02), **Memberships and Dues**, classifies expenses by category and specific percentages are applied to determine the recoverable amounts. This calculation is consistent with the way it has been done in recent cases. The effect of this adjustment on State of Oregon net operating income is an increase of $24,000.

Column (3.03) **Atmospheric Testing Restating** adjustment reflects one-third of the costs in 2013 associated with testing that occurs every three years in Oregon. The "Atmospheric Corrosion" inspection program is a federal code mandated program that requires the Company to inspect all above ground steel pipe at a frequency not to exceed three years. The Company completes this program on a three-year rotation between its three jurisdictions (Oregon, Idaho and Washington). This testing will occur in Oregon during 2013, Idaho in 2014 and Washington in 2015. This is the same method as first agreed to in UG 186, Order No. 09-422, dated October 26, 2009, and again in UG 201, Order No. 11-080, dated March 10, 2011. This methodology has also been approved in the Company's Washington and Idaho jurisdictions, providing consistency and recovery in all three jurisdictions. The result of this adjustment is a decrease in net operating income of $101,000.

Column (3.04), **Restated Salaries and Wages**, adjusts the 2014 forecasted labor expense to be consistent with the method agreed to by the parties in the rate proceeding UG-186. This method utilized Staff's approach that adjusts for 1/2 the difference between 2014 level of payroll costs planned and the annual percent based on the Consumer Price Index for non-union employees from 2011 to 2014. The Union portion of this adjustment annualizes the effect on union labor expense of the union wage adjustments implemented in April of each year. In order to simplify the matters in this case, the Company has applied this approach to its 2014 salary expense. The result of this adjustment on net operating income is an increase of $58,000, and a decrease in rate base of $60,000.

The adjustment in column (3.05), **State Income Tax**, 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 and state income tax expense is determined for Oregon gas utility operations on a stand-alone basis, or, in other words, based on the income generated by Oregon gas operations. The first $250,000 of Oregon stand-alone taxable income before state income tax was multiplied by the state statutory rate of 6.6%, and the amount over $250,000 was multiplied by the marginal tax rate for 2012 of 7.6% to determine the amount of Oregon state income tax. The impact to Oregon net operating income for the adjustment to federal and state income taxes is an increase of $3,000.

Q. Referring back to page 1, line 24, of Exhibit No. 601, what was the actual and forecasted gas rate of return realized by the Company during the test period?

A. For the State of Oregon, the actual historical test period rate of return as of December 31, 2012 was 7.41%. The restated 2014 forecasted test period rate of return is 4.69% under present rates. Thus, the Company does not, on a forecasted basis, realize the 7.83% rate of return requested by the Company in this case.

Q. How much additional net operating income would be required for the State of Oregon gas operations to allow the Company an opportunity to earn its proposed 7.83% rate of return on a forecasted basis?

A. The net operating income deficiency amounts to $5,527,000, as shown on line 5, page 2 of Exhibit No. 601. The resulting revenue requirement is shown on line 7 and amounts to $9,481,000 or an increase of 9.5% over forecasted revenues.

VIII. FUTURE RATE RELIEF

Q. Throughout this testimony you discuss and support the need for rate relief in 2014, mainly due to increases in net rate base through June 30, 2014 and increases in O&M and A&G since the Company's last filed general rate case in Docket No. UG-201. Do you expect a continued increase in operating expenses and net plant investment, and the need for additional rate relief in the immediate future beyond the 2014 level of costs requested in this filing?

A. Yes, I do. The following discussion of 2015 incremental revenue requirement is included for informational purposes only and has not been included in the Company's request for 2014. Supporting workpapers for the 2015 estimated revenue requirement also accompany the Company's filed case.

As mentioned in Mr. Thies' testimony, Avista's plans call for significant capital expenditure requirements of approximately $1.3 billion over the next five year period ending December 31, 2017. As explained earlier in my testimony, net plant balances through June 30, 2014, are included in this filing to represent the 2014 revenue requirement needed during the 2014 forecasted rate year. Therefore, starting in 2015, a revenue deficiency will exist for the additional plant moving into service through the end of 2014, as well as Oregon's share on an AMA basis of the additional $255 million of capital additions planned for 2015. This revenue deficiency will continue to incrementally grow year over year beyond the 2014 forecasted rate year in this filing, at the very least, due to the planned capital spending and lack of load growth expected over the next few years.

Specifically related to the expected 2015 Oregon revenue deficiency, at this time the Company anticipates a need for additional rate relief as of January 1, 2015 in excess of $1.3

million, or 1.2%, beyond that requested in this filing. This expected increase represents incremental increases in limited cost categories, such as new plant investment and increases based on the Consumer Price Index (CPI) on labor and certain non-labor expenses. This expected increase, however, is not all inclusive of the increased costs we expect to occur in 2015.

Q. Please provide an explanation of the cost categories included in the $1.3 million revenue requirement noted above.

A. First, the largest increase, or cost category, is due to the additional plant investment from June 30, 2014 through June 30, 2015. As detailed by Mr. DeFelice, Oregon's share of the incremental gross plant additions during this time frame, representing an additional year of plant investment beyond that included in the Company's filing, totals approximately $16.4 million. After the impact of adjusting total net plant by $11.0 million for associated accumulated depreciation and DFIT to a June 30, 2015 EOP basis, the net effect is an increase to total net rate base of $5.4 million for the Oregon jurisdiction. The incremental revenue requirement (including return on investment, depreciation and taxes, offset by the tax benefit of interest) associated with this cost category is approximately $1.28 million.

The second cost category includes increases in salaries above that included in 2014, based on a 2.1% CPI adjustment for increases expected as of March 1, 2015. Offset by the Restating Wages and Salary adjustment wage formula, the net impact of this cost category is an incremental increase in 2015 expense of approximately $169,000.

Third, the Company took the 2014 forecasted non-labor expense determined in the 2.00 Forecasted Expenses Adjustment and applied the 2.1% CPI factor for 2015, providing an incremental increase in 2015 non-labor expenses of approximately $198,000.

Lastly, the Company offset the above incremental expenses by the incremental expected revenue from any additional load growth expected in 2015. A small amount of load growth is expected in 2015 as compared to 2014. As shown in Mr. Ehrbar's Exhibit No. 903, the 2015 incremental revenue expected is approximately $363,000. The total net revenue requirement from net plant investment and increases in 2015 salary and non-labor expenses, offset by incremental 2015 retail revenues, results in the $1.3 million noted above.

IX. COST ASSIGNMENT AND ALLOCATION PROCEDURES

Q. Would you please describe the utility services provided by the Company and identify the jurisdictions within which the utility services are provided?

A. Yes. The Company provides electric service in two retail jurisdictions[6] and natural gas service in three retail jurisdictions.

Electric service is provided to retail customers in eastern Washington and northern Idaho and is identified for accounting purposes as the electric operating division.

Retail natural gas service is also provided in eastern Washington and northern Idaho and is referred to as the WA/ID natural gas division, or as the North natural gas division. A separate operating division provides natural gas service in central and southwest Oregon and is separately referred to as our Oregon jurisdiction, or the South natural gas division.

Q. How does the Company assign costs to its separate operating divisions?

A. Whenever possible, the Company directly assigns to services and jurisdictions its revenues, operating costs and plant. For example, approximately 92% of Oregon's 2012 <u>costs</u> were directly assigned and 8% were allocated. Approximately 93% of Oregon's <u>net</u>

[6] Avista serves approximately 25 retail customers in Montana.

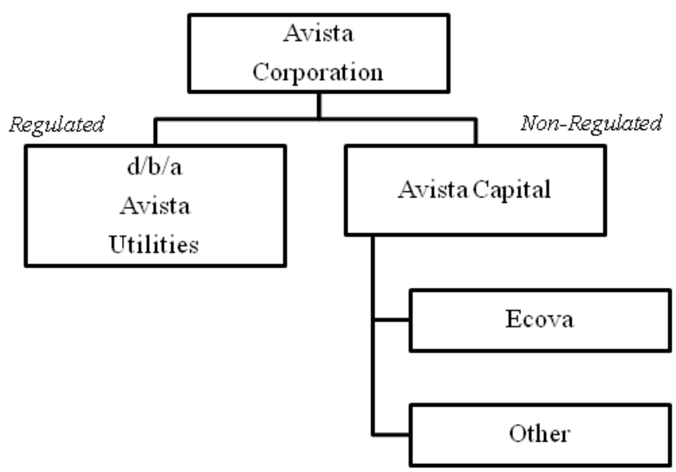
plant at December 31, 2012 was directly assigned and 7% was allocated.

Q. For costs not directly assigned, please explain how the Company accounts for these "common" costs that must be allocated among its various operating divisions?

A. The Company uses service codes and jurisdiction codes on all accounting transactions to account for costs by operating division or to indicate that a cost should be allocated between operating divisions. Both service codes and jurisdiction codes consist of two-digit alpha codes, described below. The use of service/jurisdiction codes enables the assignment and allocation of costs and plant to operating divisions. The assignments and allocations are used for internal reporting, regulatory reporting and ratemaking purposes.

Q. How are costs allocated to non-utility divisions or subsidiary companies of Avista Corp.?

A. Avista Utilities is the regulated operating division of Avista Corp. An organization chart for Avista Corp. follows:



On a regular basis, certain officers and general office employees of Avista Corporation, dba Avista Utilities, spend time on corporate service support, such as accounting, federal income tax filing, planning, or incur costs for supplies, postage, legal, graphic services, etc. for subsidiaries. Their time and costs are directly charged to suspense accounts and then billed to the subsidiary or directly charged to non-utility FERC accounts. Therefore, the Company does not allocate costs to subsidiaries or non-utility accounts as part of the allocation procedures described below.

An example of the Company's process for recording subsidiary-related costs is provided in Illustration No. 2 below.

Illustration No. 2:

Detail of Directors' Fees for 2012
($000's)

Total Directors' Fees	$	1,583
Less: Ecova Subsidiary Directors' Fees Charged to FERC 417/186		72
Avista Corp. Directors' Fees		1,511
Less: Avista Corp. Amounts Charged to Non-utility (FERC 417)		150
Utility Directors' Fees - System	$	1,361
Utility Directors' Fees - Oregon Allocated	$	112

Illustration No. 2 shows that a total of $1.58 million of directors' fees was paid in 2012. Of this amount, $72,000 was direct charged to either a subsidiary receivable or to a non-utility FERC account related to Ecova's Board of Director fees. In addition, of the $1.51 million of Avista Corp. Board of Director Fees, $150,000 was directly charged to a non-utility FERC account related to subsidiary operations.[7] The remaining $1.36 million that was charged to the utility is allocated through the Company's allocation processes.

[7] The Company regularly surveys each member of its Avista Corp Board of Directors to determine how much of each member's time while serving on the Board is devoted to activities not directly related to the operations of the Utility itself, so that costs may be appropriately assigned to utility and non-utility operations. Current Board of Directors survey results show a 90% assignment to utility, and 10% to non-utility.

Q. Do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. When the Company designed the allocation methodology that is being used today, the specific objectives identified were as follows:

a) The method must be acceptable to all regulators to prevent any stranded costs or investment,
b) The number of cost allocation methods should be minimized,
c) The method needs to be simple,
d) The method needs to have a sound, rational basis,
e) Allocations under the method should be automated, and
f) The method needs to produce reasonable results.

These objectives are still relevant and required today. The Company believes the methodology continues to meet these overall objectives.

The overall goal the Company was trying to accomplish as it designed its allocation methodology was to produce a reasonable method to allocate common costs and common plant to the operating units. The method ultimately proposed by Avista and approved by the four Commissions (Washington, Idaho, Oregon and California) produced a reasonable allocation of common costs.

Q. Please explain when the Company began using the current methodology?

A. The current method was developed and presented to the Commission Staffs of the four state utility commissions for approval in 1993. The Company obtained approval letters from each jurisdiction and implemented the new utility codes and allocation methodology in 1994.[8]

Q. Would you please summarize the assignment and utility code/allocation method currently in use?

A. Yes. To begin with, revenues, operating costs and plant are directly assigned to services and jurisdictions whenever possible.

For those costs not directly assigned, the costs are allocated using allocation factors. The Company annually computes the allocation factors using actual direct costs and the methodology approved by the Commissions. Updating the factors with current costs and customers on an annual basis is appropriate so growth in each jurisdiction is factored into the current year allocation. When the factors are updated annually, the factors are reviewed to identify any unusual trends or unexpected shifts in costs.

The allocation factors used to allocate common costs are comprised of an equal weighting of four factors, and are therefore called "4-factors". The four factors are (1) direct O&M and A&G costs, excluding labor and resource costs, (2) direct O&M and A&G labor, (3) number of customers, and (4) net direct plant. The three 4-factors used to allocate the common costs to an operating division level include Factor 7 (CD.AA), Factor 8 (GD.AA) and Factor 9 (CD.AN). These factors are entered into the general ledger so the allocation of costs to the electric division (WA/ID), natural gas north division (WA/ID), and natural gas south division (OR) occurs automatically in the general ledger.

The number of customers is used as the allocator for common portions of FERC Accounts 901-905 (Customer Accounts Expense), FERC Accounts 906-910 (Customer

[8] It should be noted that the Company's allocation methodology and it actual allocation of costs using the factors computed using that methodology have been provided in each general rate case filed by the Company in each of its jurisdictions since the method was implemented.

Service and Information Expense), and FERC Accounts 911-917 (Sales Expenses). It was determined that these costs are heavily influenced by the number of customers, and therefore, the ratio based on customers was more appropriate than the over-all 4-factor. The overall 4-factor allocator is used for the common portion of FERC Accounts 920-935 (Administrative and General) and common plant.

Other jurisdictional allocation factors (i.e. common electric costs that are split between Washington and Idaho), which are based on the same principles as allocators that are used to allocate costs and plant to electric and natural gas services, are applied in a jurisdictional allocation model outside of the general ledger system. This model produces the monthly Results of Operations reports. Oregon's Results of Operations report as of December 31, 2012 has been provided with my workpapers at Section 1.00.

Q. Did the Company recently meet with Staff and other interested parties to explain the methodology?

A. Yes. In accordance with Order 11-080 dated March 10, 2011, issued in the Company's last general rate case (UG-201), the Company was required to meet with the Parties prior to filing its next general rate case to discuss the Company's allocation processes and methodologies. The Company met with the Parties on July 15, 2013 for this purpose. The presentation used by the Company at this meeting is provided as Exhibit No. 603.

Q. During this meeting, were any costs identified by the Parties that could be allocated using a different allocation method than being used by the Company?

A. Yes. One of the categories discussed was the cost of Avista's payroll department. Avista currently has four employees that process the payroll for the utility. Those costs are recorded as a common cost and allocated to all services and all jurisdictions.

The Company currently uses the 4-factor: Factor 7. The four factors, as discussed above, include (1) direct O&M and A&G costs, excluding labor and resource costs, (2) direct O&M and A&G labor, (3) number of customers, and (4) net direct plant. Some of the Parties discussed whether all four factors should be used to allocate the cost of the payroll department. Rather than using the overall 4-factor, it was discussed whether only direct labor costs would be a better allocator for those costs.

The Company continues to believe the overall 4-factor is appropriate for these costs for several reasons. First, large capital investment in one service/jurisdiction will impact the amount of capital labor that is used in that service/jurisdiction. Since the payroll department processes all payroll, including capitalized labor, the use of the 4-factor, which includes net plant investment in the allocation, is appropriate. Second, the Company currently allocates costs at the FERC account level. If the Company were to allocate costs based on operational organizations (i.e. the payroll department), the allocation of costs would be extremely more complex. The general ledger and Results of Operations model used by the Company would have to be reprogrammed to account for this new level of allocations. The Company believes the methodology used today at the FERC account level produces a reasonable allocation of the common costs.

Q. In summary, do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. The Company is aware that there are many ways in which common costs could be allocated, but we believe the method used by Avista produces a reasonable allocation of costs. It has been reviewed and accepted by all jurisdictions in which Avista serves and remains a sound basis for allocating costs.

X. OTHER ISSUES

Q. In Avista's prior general rate case, Docket UG-201, Order No. 11-080, the Company was ordered to complete certain requirements prior to or with the Company's next general rate case filing. Would you please provide a summary of those items and how they have been addressed by the Company?

A. Yes. Detailed below are three items that the Company was required to address based on Order No. 11-080 in Dockets UG-201, page 9 Paragraph E. Other Issues (and per the Stipulation Resolving All Issues). Shown below are the requirements and how these items have been addressed.

Item 1 – "Avista has an on-going project to review its accounting policies and procedures, to provide training to its employees, and to conduct an audit of total Company accounting practices. The Company agrees to provide the parties with copies of all reports associated with this project."

Company Response:

- In 2011 Avista completed its review of its accounting policies and procedures:
  - Accounting guidelines were developed, communicated, and made available to all employees;
  - Formal training was provided to all impacted Company employees;
  - Internal Audit completed its internal audit on the Company's 2010 expenses;
  - Detective controls, including the review of specific accounts and expenditure types, were implemented; and
  - Experts within the Company were identified as a resource for employees to provide departments with guidance and support to ensure compliance with the Company's accounting guidelines.
  - The findings resulting from this work were summarized in the Company's "Internal Review of Accounting Practices" report and provided to all Oregon parties in May 2011.
- In March 2012 the Company provided to all Oregon parties the two internal audit reports for 2011 titled "Accounting Practices Audit" and "Low-Income Rate Assistance Program Accounting Practices Audit."
- In May 2013 the Company provided to all Oregon parties the two internal audit reports for 2012 titled "Accounting Practices Audit" and "Low-Income Rate Assistance Program Accounting Practices Audit."

In addition, prior to filing the Company's general rate case and determination of the requested revenue requirement for this proceeding, the Company completed an extensive review if its 2012 expenses included in its test period, removing expenses found to be charged to the Utility in error, or inaccurately allocated to the Oregon natural gas jurisdiction. The detail of this adjustment can be found within my workpapers labeled (1.02) Miscellaneous Adjustment provided with the company's filing. The impact of this restating adjustment resulted in a net reduction to Oregon operating expenses of approximately $4,000.

Item 2 – In future rate case filings, Avista will prepare a forecasted results of operations report that will be used as the test year.

Company Response:
Included as Andrews Exhibit Nos. 601 (Summary) and 602 (Detailed by FERC Account), the Company has provided its Results of Operations report on a 2014 forecasted basis.

Item 3 – Avista agrees to meet with the stipulating parties prior to the Company's next general rate case filing to discuss the Company's allocation processes and methods.

Company Response:
As discussed above in Section IX. Cost Assignment and Allocation Procedures, the Company met with the parties on July 15, 2013 to discuss the Company's allocation processes and methods.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

ELIZABETH M. ANDREWS
Exhibit No. 601

Revenue Requirement and Allocations

AVISTA UTILITIES
OREGON NATURAL GAS
OREGON JURISDICTION FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2014

		PRESENT RATES			WITH PROPOSED RATES	
Line No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2014 AMA Forecasted Test Period	Proposed Revenues & Related Exp	Forecasted Proposed Total (AMA)
		a	*b*	*c*	*d*	*e*
1	OPERATING REVENUES					
2	Total General Business	$95,274	1,161	96,435	9,481	105,916
3	Total Transportation	2,888	35	2,923	0	2,923
4	Other Revenues	67,391	(67,247)	144	0	144
5	Total Operating Revenues	165,553	(66,051)	99,502	9,481	108,983
6						
7	OPERATING EXPENSES					
8	Gas Purchased	119,814	(64,355)	55,459	0	55,459
9	Operation and Maintenance	12,734	(907)	11,827	51	11,878
10	Administration & General	7,675	128	7,803	229	8,032
11	Total Operation & Maintenance	140,223	(65,134)	75,089	280	75,369
12						
13	DEPRECIATION, AMORTIZATION, TAXES					
14	Taxes Other than Income	5,654	(751)	4,903	699	5,602
15	Depreciation & Amortization	5,022	4,027	9,049	0	9,049
16	Total Operating Expenses	150,899	(61,858)	89,041	979	90,020
17						
18	OPERATING INCOME BEFORE FIT	14,654	(4,193)	10,461	8,502	18,963
19						
20	INCOME TAXES					
21	Current Federal Income Taxes	72	(1,355)	(1,283)	2,976	1,693
22	Debt Interest	0	(288)	(288)	0	(288)
23	Deferred Federal Income Taxes	3,817	0	3,817	0	3,817
24	State Income Taxes	268	(323)	(55)	0	(55)
25	Total Income Taxes	4,157	(1,966)	2,191	2,976	5,167
26						
27	NET OPERATING INCOME	$10,497	($2,227)	$8,270	$5,526	$13,796
28						
29						
30	RATE BASE					
31	Utility Plant in Service	269,913	42,241	312,154	0	312,154
32	Less: Accum Depr and Amort	(94,566)	(11,976)	(106,542)	0	(106,542)
33	Net Utility Plant	175,347	30,265	205,612	0	205,612
34						
35	Accumulated Deferred FIT	(36,866)	(7,694)	(44,560)	0	(44,560)
36	Inventory	3,084	0	3,084	0	3,084
37	Prepaid Pension (1)	0	5,710	5,710	0	5,710
38	Working Capital	0	6,355	6,355	0	6,355
39						
40	TOTAL RATE BASE	$141,565	$34,636	$176,201	$0	$176,201
41						
42	RATE OF RETURN	7.41%		4.69%		7.83%

(1) Prepaid Pension Asset of $5.71 million is offset by $2.0 million Accumulated Deferred Federal Income Tax (ADFIT), resulting in a net Prepaid Pension rate base amount of $3.71 million. See detail information at Andrews Exhibit No. 602, page 5.

AVISTA UTILITIES
OREGON NATURAL GAS
CONVERSION FACTOR EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2012

Line No.	Description	(000's of Dollars)	
1	Forecasted Rate Base	$176,201	-
2	Proposed Rate of Return	7.83%	
3	Net Operating Income Requirement	$13,797	
4	Forecasted Net Operating Income	$8,270	-
5	Net Operating Income Deficiency	$5,527	
6	Conversion Factor	0.58293	
7	Revenue Requirement	$9,481	
8	Total General Business Revenues	$99,358	
9	Percentage Revenue Increase	9.5%	

	AVISTA PROPOSED COST OF CAPITAL		
	Capital	**Cost**	**Weighted**
Long Term Debt	50.000%	5.550%	2.780%
Common Equity	50.000%	10.100%	5.050%
Total	100.00%		7.83%

AVISTA UTILITIES
OREGON NATURAL GAS
CONVERSION FACTOR EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2012

Line No.	Description		Factor	Amounts
1	Revenues		1.000000	9,481
	Expense:			
2	Uncollectibles		0.005329	51
3	Commission Fees		0.002500	24
4	Energy Resource Supplier Assessment		0.000751	7
5	Franchise Fees		0.020842	198
6	Oregon Excise Tax		0.073764	699
6	Total Expense		0.103186	979
7	Net Operating Income Before FIT		0.896814	8,502
8	Federal Income Tax @	35.00%	0.313885	2,976
9	REVENUE CONVERSION FACTOR		0.582929	5,526

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED 2012 AMA HISTORICAL TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description		Per Results of Operations Report	Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment	Weather Normalization Sales/Purch
	Adjustment Number		1.00	1.01	1.02	1.03	1.04
	Workpaper Refernce		G-ROO	G-FAF	G-MR	G-EAS	G-WN
	REVENUES						
8	SALES TO ULTIMATE CUSTOMERS		95,274	0	0	1,823	(556)
12	TRANSPORTATION REVENUES		2,888	0	0	(16)	0
19	OTHER OPERATING REVENUES		67,391	0	0	(36)	(67,211)
21	**TOTAL GAS REVENUES**		**165,553**	**0**	**0**	**1,771**	**(67,767)**
22							
23	**EXPENSES**						
28	TOTAL GAS PURCHASES		119,814	0	0	0	(63,161)
37	TOTAL OTHER GAS SUPPLY EXPENSE		246	18	0	4,730	(4,432)
39	**TOTAL PRODUCTION EXPENSES**		**120,060**	**18**	**0**	**4,730**	**(67,593)**
40							
45	TOTAL UG STORAGE OPER EXP		107	0	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		112	0	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		7	0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**226**	**0**	**0**	**0**	**0**
56							
79	DISTRIBUTION O&M EXPENSES		6,652	22	0	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		3,790	0	0	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		5,647	0	0	(1,574)	(11)
89	**TOTAL DISTRIBUTION EXPENSES**		**16,089**	**22**	**0**	**(1,574)**	**(11)**
90							
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,325**	**(3)**	**0**	**13**	**(3)**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**2,399**	**0**	**(2)**	**(1,848)**	**0**
109	**SALES OPERATING EXPENSES**		**5**	**0**	**0**	**0**	**0**
110							
123	ADMIN & GENERAL OPERATING EXP		7,675	157	(2)	9	(2)
126	TOTAL A&G DEPRCIATION EXP		1,169	0	0	0	0
131	TOTAL A&G AMRT/NON-FIT TAXES		760	0	0	0	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**9,604**	**157**	**(2)**	**9**	**(2)**
136							
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**(809)**	**0**	**0**	**809**	**0**
144							
145	**TOTAL EXPENSES BEFORE FIT**		**150,899**	**194**	**(4)**	**2,139**	**(67,609)**
146							
147	**NET OPERATING INCOME (LOSS) BEFORE FIT**		**14,654**	**(194)**	**4**	**(368)**	**(158)**
148							
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	72	(63)	1	(119)	(51)
152	DEBT INTEREST	3.078%	0	0	0	0	0
153	DEFERRED INCOME TAX		3,817	0	0	0	0
154	STATE INCOME TAXES	7.60%	268	(15)	0	(28)	(12)
155	**GAS NET OPERATING INCOME (LOSS)**		**10,497**	**(117)**	**2**	**(221)**	**(95)**
156							
157	**RATE BASE**						
158	**PLANT IN SERVICE**						
162	TOTAL INTANGIBLE PLANT		4,261	0	0	0	0
177	TOTAL UNDERGROUND STORAGE PLANT		5,773	0	0	0	0
182	TOTAL PRODUCTION PLANT		8	0	0	0	0
195	TOTAL DISTRIBUTION PLANT		240,252	0	0	0	0
208	TOTAL GAS GENERAL PLANT		19,619	0	0	0	0
210	**GROSS PLANT IN SERVICE**		**269,913**	**0**	**0**	**0**	**0**
211							
216	TOTAL ACCUMULATED DEPRECIATION		(92,659)	0	0	0	0
217							
222	TOTAL ACCUMULATED AMORTIZATION		(1,907)	0	0	0	0
224	**TOTAL ACCUMULATED DEPR/AMORT**		**(94,566)**	**0**	**0**	**0**	**0**
225							
226	NET GAS UTILITY PLANT before DFIT		175,347	0	0	0	0
227							
228	ACCUMULATED DFIT						
229	ADFIT - Gas Plant in Service		(33,625)	0	0	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		(2,681)	0	0	0	0
231	ADFIT - Common Plant (283750 from C-DTX)		(24)	0	0	0	0
232	ADFIT - Bond Redemptions		(536)	0	0	0	0
233	ADFIT - Prepaid Pension		0	0	0	0	0
234	**TOTAL ACCUMULATED DFIT**		**(36,866)**	**0**	**0**	**0**	**0**
235							
236	**NET GAS UTILITY PLANT**		**138,481**	**0**	**0**	**0**	**0**
237							
243	**TOTAL GAS INVENTORY**		**3,084**	**0**	**0**	**0**	**0**
244							
245	OTHER REGULATORY ASSETS						
246	Prepaid Pension		0	0	0	0	0
247	Working Capital		0	0	0	0	0
248	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**0**	**0**
249							
250	**NET RATE BASE**		**141,565**	**0**	**0**	**0**	**0**
251							
252	RATE OF RETURN		**7.41%**				
253							
254	**REVENUE REQUIREMENT**		**1,008**	**200**	**(4)**	**379**	**163**

AVISTA UTILITIES
OREGON NATURAL GAS
RESTATED 2012 AMA HISTORICAL TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description		Restate Debt Adjustment	Restated Historical 2012 AMA Test Period Total
	Adjustment Number		1.05	
	Workpaper Refernce		G-RD	
	REVENUES			
8	SALES TO ULTIMATE CUSTOMERS		0	**96,541**
12	TRANSPORTATION REVENUES		0	**2,872**
19	OTHER OPERATING REVENUES		0	**144**
21	**TOTAL GAS REVENUES**		**0**	**99,557**
22				
23	**EXPENSES**			
28	TOTAL GAS PURCHASES		0	**56,653**
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	**562**
39	**TOTAL PRODUCTION EXPENSES**		**0**	**57,215**
40				
45	TOTAL UG STORAGE OPER EXP		0	**107**
48	TOTAL UG STORAGE DEPRCIATION EXP		0	**112**
51	TOTAL UG STORAGE NON-FIT TAXES		0	**7**
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**226**
56				
79	DISTRIBUTION O&M EXPENSES		0	**6,674**
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	**3,790**
85	TOTAL DISTRIBUTION NON-FIT TAXES		0	**4,062**
89	**TOTAL DISTRIBUTION EXPENSES**		**0**	**14,526**
90				
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**0**	**3,332**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**549**
109	**SALES OPERATING EXPENSES**		**0**	**5**
110				
123	ADMIN & GENERAL OPERATING EXP		0	**7,837**
126	TOTAL A&G DEPRCIATION EXP		0	**1,169**
131	TOTAL A&G AMRT/NON-FIT TAXES		0	**760**
135	**TOTAL ADMIN & GENERAL EXPENSES**		**0**	**9,766**
136				
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**
144				
145	**TOTAL EXPENSES BEFORE FIT**		**0**	**85,619**
146				
147	**NET OPERATING INCOME (LOSS) BEFORE FIT**		**0**	**13,938**
148				
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	0	**(160)**
152	DEBT INTEREST	3.078%	96	**96**
153	DEFERRED INCOME TAX		0	**3,817**
154	STATE INCOME TAXES	7.60%	0	**214**
155	**GAS NET OPERATING INCOME (LOSS)**		**(96)**	**9,971**
156				
157	**RATE BASE**			
158	**PLANT IN SERVICE**			
162	TOTAL INTANGIBLE PLANT		0	**4,261**
177	TOTAL UNDERGROUND STORAGE PLANT		0	**5,773**
182	TOTAL PRODUCTION PLANT		0	**8**
195	TOTAL DISTRIBUTION PLANT		0	**240,252**
208	TOTAL GAS GENERAL PLANT		0	**19,619**
210	**GROSS PLANT IN SERVICE**		**0**	**269,913**
211				
216	TOTAL ACCUMULATED DEPRECIATION		0	**(92,659)**
217				
222	TOTAL ACCUMULATED AMORTIZATION		0	**(1,907)**
224	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**(94,566)**
225				
226	NET GAS UTILITY PLANT before DFIT		0	**175,347**
227				
228	ACCUMULATED DFIT			
229	ADFIT - Gas Plant in Service		0	**(33,625)**
230	ADFIT - Common Plant (282900 from C-DTX)		0	**(2,681)**
231	ADFIT - Common Plant (283750 from C-DTX)		0	**(24)**
232	ADFIT - Bond Redemptions		0	**(536)**
233	ADFIT - Prepaid Pension		0	**0**
234	**TOTAL ACCUMULATED DFIT**		**0**	**(36,866)**
235				
236	**NET GAS UTILITY PLANT**		**0**	**138,481**
237				
243	**TOTAL GAS INVENTORY**		**0**	**3,084**
244				
245	OTHER REGULATORY ASSETS			
246	Prepaid Pension		0	**0**
247	Working Capital		0	**0**
248	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**
249				
250	**NET RATE BASE**		**0**	**141,565**
251				
252	RATE OF RETURN			**7.04%**
253				
254	**REVENUE REQUIREMENT**		**165**	**1,911**

AVISTA UTILITIES
OREGON NATURAL GAS
FORECASTED 2014 AMA RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description		Restated Historical 2012 AMA Test Period Total	Forecast Expense Adjustment	Forecast Revenue Load Adjustment	Forecast Labor & Benefits Adjustment	Forecast VSIP Amort Adjustment
	Adjustment Number			2.00	2.01	2.02	2.03
	Workpaper Refernce			G-FE	G-FR	G-FLB	G-VSIP
	REVENUES						
8	SALES TO ULTIMATE CUSTOMERS		96,541	0	(106)	0	0
12	TRANSPORTATION REVENUES		2,872	0	51	0	0
19	OTHER OPERATING REVENUES		144	0	0	0	0
21	**TOTAL GAS REVENUES**		**99,557**	**0**	**(55)**	**0**	**0**
22							
23	**EXPENSES**						
28	TOTAL GAS PURCHASES		56,653	0	(1,194)	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		562	5	1	11	0
39	**TOTAL PRODUCTION EXPENSES**		**57,215**	**5**	**(1,193)**	**11**	**0**
40							
41	UNDERGROUND STORAGE EXPENSES:						
45	TOTAL UG STORAGE OPER EXP		107	5	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		112	0	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		7	0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**226**	**5**	**0**	**0**	**0**
56							
79	DISTRIBUTION O&M EXPENSES		6,674	103	0	198	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		3,790	0	0	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		4,062	0	(1)	0	0
89	**TOTAL DISTRIBUTION EXPENSES**		**14,526**	**103**	**(1)**	**198**	**0**
90							
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,332**	**50**	**0**	**82**	**0**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**549**	**11**	**0**	**7**	**0**
109	**SALES OPERATING EXPENSES**		**5**	**0**	**0**	**0**	**0**
110							
123	ADMIN & GENERAL OPERATING EXP		7,837	210	0	73	183
126	TOTAL A&G DEPRCIATION EXP		1,169	0	0	0	0
131	TOTAL A&G AMRT/NON-FIT TAXES		760	0	0	0	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**9,766**	**210**	**0**	**73**	**183**
136							
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**0**	**0**
144							
145	**TOTAL EXPENSES BEFORE FIT**		**85,619**	**384**	**(1,194)**	**371**	**183**
146							
147	**NET OPERATING INCOME (LOSS) BEFORE FIT**		**13,938**	**(384)**	**1,139**	**(371)**	**(183)**
148							
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	(160)	(124)	368	(120)	(59)
152	DEBT INTEREST	2.780%	96	0	0	(41)	0
153	DEFERRED INCOME TAX		3,817	0	0	0	0
154	STATE INCOME TAXES	7.60%	214	(29)	87	(28)	(14)
155	**GAS NET OPERATING INCOME (LOSS)**		**9,971**	**(231)**	**684**	**(182)**	**(110)**
156							
157	**RATE BASE**						
162	TOTAL INTANGIBLE PLANT		4,261	0	0	0	0
177	TOTAL UNDERGROUND STORAGE PLANT		5,773	0	0	0	0
182	TOTAL PRODUCTION PLANT		8	0	0	0	0
195	TOTAL DISTRIBUTION PLANT		240,252	0	0	0	0
208	TOTAL GAS GENERAL PLANT		19,619	0	0	0	0
209							
210	**GROSS PLANT IN SERVICE**		**269,913**	**0**	**0**	**0**	**0**
211							
212	ACCUMULATED DEPRECIATION						
213	Underground Storage		(354)	0	0	0	0
214	Distribution Plant		(86,493)	0	0	0	0
215	General Plant		(5,812)	0	0	0	0
216	TOTAL ACCUMULATED DEPRECIATION		(92,659)	0	0	0	0
217							
222	TOTAL ACCUMULATED AMORTIZATION		(1,907)	0	0	0	0
224	**TOTAL ACCUMULATED DEPR/AMORT**		**(94,566)**	**0**	**0**	**0**	**0**
225							
226	NET GAS UTILITY PLANT before DFIT		175,347	0	0	0	0
227							
228	ACCUMULATED DFIT						
229	ADFIT - Gas Plant in Service		(33,625)	0	0	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		(2,681)	0	0	0	0
231	ADFIT - Common Plant (283750 from C-DTX)		(24)	0	0	0	0
232	ADFIT - Bond Redemptions		(536)	0	0	0	0
233	ADFIT - Prepaid Pension		0	0	0	(2,000)	0
234	**TOTAL ACCUMULATED DFIT**		**(36,866)**	**0**	**0**	**(2,000)**	**0**
235							
236	**NET GAS UTILITY PLANT**		**138,481**	**0**	**0**	**(2,000)**	**0**
237							
243	**TOTAL GAS INVENTORY**		**3,084**	**0**	**0**	**0**	**0**
244							
245	OTHER REGULATORY ASSETS						
246	Prepaid Pension		0	0	0	5,710	0
247	Working Capital		0	0	0	0	0
248	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**5,710**	**0**
249							
250	**NET RATE BASE**		**141,565**	**0**	**0**	**3,710**	**0**
251							
252	RATE OF RETURN		7.04%				
253							
254	**REVENUE REQUIREMENT**		**1,911**	**396**	**(1,174)**	**810**	**189**

AVISTA UTILITIES
OREGON NATURAL GAS
FORECASTED 2014 AMA RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description		Forecast Property Tax Adjustment	2012 Capital Activity Adjustment	2013 Capital Activity Adjustment	2014 Capital Activity Adjustment	Depreciation Study Adjustment
	Adjustment Number		2.04	2.05	2.06	2.07	2.08
	Workpaper Refernce		G-FPT	G-CAP12	G-CAP13	G-CAP14	G-DEPR
	REVENUES						
8	SALES TO ULTIMATE CUSTOMERS		0	0	0	0	0
12	TRANSPORTATION REVENUES		0	0	0	0	0
19	OTHER OPERATING REVENUES		0	0	0	0	0
21	**TOTAL GAS REVENUES**		**0**	**0**	**0**	**0**	**0**
22							
23	**EXPENSES**						
28	TOTAL GAS PURCHASES		0	0	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	0	0	0
39	**TOTAL PRODUCTION EXPENSES**		**0**	**0**	**0**	**0**	**0**
40							
41	UNDERGROUND STORAGE EXPENSES:						
45	TOTAL UG STORAGE OPER EXP		0	0	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		0	1	2	1	(7)
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**1**	**2**	**1**	**(7)**
56							
79	DISTRIBUTION O&M EXPENSES		0	0	0	0	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	45	272	127	1,305
85	TOTAL DISTRIBUTION NON-FIT TAXES		200	62	367	206	0
89	**TOTAL DISTRIBUTION EXPENSES**		**200**	**107**	**639**	**333**	**1,305**
90							
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**0**	**0**	**0**	**0**	**0**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**0**	**0**	**0**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**0**	**0**	**0**
110							
123	ADMIN & GENERAL OPERATING EXP		0	0	0	0	0
126	TOTAL A&G DEPRCIATION EXP		0	1	28	0	226
131	TOTAL A&G AMRT/NON-FIT TAXES		0	75	433	528	181
135	**TOTAL ADMIN & GENERAL EXPENSES**		**0**	**76**	**461**	**528**	**407**
136							
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**0**	**0**
144							
145	**TOTAL EXPENSES BEFORE FIT**		**200**	**184**	**1,102**	**862**	**1,705**
146							
147	**NET OPERATING INCOME (LOSS) BEFORE FIT**		**(200)**	**(184)**	**(1,102)**	**(862)**	**(1,705)**
148							
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	(65)	(60)	(356)	(279)	(551)
152	DEBT INTEREST	2.780%	0	(18)	(174)	(93)	11
153	DEFERRED INCOME TAX		0	0	0	0	0
154	STATE INCOME TAXES	7.60%	(15)	(14)	(84)	(66)	(130)
155	**GAS NET OPERATING INCOME (LOSS)**		**(120)**	**(93)**	**(488)**	**(425)**	**(1,035)**
156							
157	**RATE BASE**						
162	TOTAL INTANGIBLE PLANT		0	412	1,902	6,584	0
177	TOTAL UNDERGROUND STORAGE PLANT		0	31	138	78	0
182	TOTAL PRODUCTION PLANT		0	0	0	0	0
195	TOTAL DISTRIBUTION PLANT		0	2,977	19,099	6,372	0
208	TOTAL GAS GENERAL PLANT		0	701	3,298	709	0
209							
210	**GROSS PLANT IN SERVICE**		**0**	**4,121**	**24,437**	**13,743**	**0**
211							
212	ACCUMULATED DEPRECIATION						
213	Underground Storage		0	(56)	(114)	(58)	4
214	Distribution Plant		0	(1,098)	(3,995)	(2,148)	(653)
215	General Plant		0	7	(1,301)	(792)	(74)
216	TOTAL ACCUMULATED DEPRECIATION		0	(1,147)	(5,410)	(2,998)	(723)
217							
222	TOTAL ACCUMULATED AMORTIZATION		0	(4)	(926)	(751)	(17)
224	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**(1,151)**	**(6,336)**	**(3,749)**	**(740)**
225							
226	NET GAS UTILITY PLANT before DFIT		0	2,970	18,101	9,994	(740)
227							
228	ACCUMULATED DFIT						
229	ADFIT - Gas Plant in Service		0	(1,222)	(2,138)	(1,043)	(237)
230	ADFIT - Common Plant (282900 from C-DTX)		0	(171)	(291)	(570)	(22)
231	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0	0
232	ADFIT - Bond Redemptions		0	0	0	0	0
233	ADFIT - Prepaid Pension		0	0	0	0	0
234	**TOTAL ACCUMULATED DFIT**		**0**	**(1,393)**	**(2,429)**	**(1,613)**	**(259)**
235							
236	**NET GAS UTILITY PLANT**		**0**	**1,577**	**15,672**	**8,381**	**(999)**
237							
243	**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**	**0**
244							
245	OTHER REGULATORY ASSETS						
246	Prepaid Pension		0	0	0	0	0
247	Working Capital		0	0	0	0	0
248	**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**0**	**0**
249							
250	**NET RATE BASE**		**0**	**1,577**	**15,672**	**8,381**	**(999)**
251							
252	RATE OF RETURN						
253							
254	**REVENUE REQUIREMENT**		**206**	**371**	**2,942**	**1,854**	**1,642**

AVISTA UTILITIES
OREGON NATURAL GAS
FORECASTED 2014 AMA RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description		Working Capital Adjustment	Forecast Insurance Adjustment	Forecasted 2014 AMA ROO Total
	Adjustment Number		2.09	2.10	
	Workpaper Refernce		G-FWC	G-IA	
	REVENUES				
8	SALES TO ULTIMATE CUSTOMERS		0	0	**96,435**
12	TRANSPORTATION REVENUES		0	0	**2,923**
19	OTHER OPERATING REVENUES		0	0	**144**
21	**TOTAL GAS REVENUES**		**0**	**0**	**99,502**
22					
23	**EXPENSES**				
28	TOTAL GAS PURCHASES		0	0	**55,459**
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	0	**579**
39	**TOTAL PRODUCTION EXPENSES**		**0**	**0**	**56,038**
40					
41	UNDERGROUND STORAGE EXPENSES:				
45	TOTAL UG STORAGE OPER EXP		0	0	**112**
48	TOTAL UG STORAGE DEPRCIATION EXP		0	0	**109**
51	TOTAL UG STORAGE NON-FIT TAXES		0	0	**7**
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**0**	**0**	**228**
56					
79	DISTRIBUTION O&M EXPENSES		0	0	**6,975**
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	0	**5,539**
85	TOTAL DISTRIBUTION NON-FIT TAXES		0	0	**4,896**
89	**TOTAL DISTRIBUTION EXPENSES**		**0**	**0**	**17,410**
90					
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**0**	**0**	**3,464**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**0**	**0**	**567**
109	**SALES OPERATING EXPENSES**		**0**	**0**	**5**
110					
123	ADMIN & GENERAL OPERATING EXP		0	76	**8,379**
126	TOTAL A&G DEPRCIATION EXP		0	0	**1,424**
131	TOTAL A&G AMRT/NON-FIT TAXES		0	0	**1,977**
135	**TOTAL ADMIN & GENERAL EXPENSES**		**0**	**76**	**11,780**
136					
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**
144					
145	**TOTAL EXPENSES BEFORE FIT**		**0**	**76**	**89,492**
146					
147	**NET OPERATING INCOME (LOSS) BEFORE FIT**		**0**	**(76)**	**10,010**
148					
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	0	(25)	**(1,430)**
152	DEBT INTEREST	2.780%	(71)	0	**(289)**
153	DEFERRED INCOME TAX		0	0	**3,817**
154	STATE INCOME TAXES	7.60%	0	(6)	**(85)**
155	**GAS NET OPERATING INCOME (LOSS)**		**71**	**(46)**	**7,997**
156					
157	**RATE BASE**				
162	TOTAL INTANGIBLE PLANT		0	0	**13,159**
177	TOTAL UNDERGROUND STORAGE PLANT		0	0	**6,020**
182	TOTAL PRODUCTION PLANT		0	0	**8**
195	TOTAL DISTRIBUTION PLANT		0	0	**268,700**
208	TOTAL GAS GENERAL PLANT		0	0	**24,327**
209					
210	**GROSS PLANT IN SERVICE**		**0**	**0**	**312,214**
211					
212	ACCUMULATED DEPRECIATION				
213	Underground Storage		0	0	**(578)**
214	Distribution Plant		0	0	**(94,387)**
215	General Plant		0	0	**(7,972)**
216	TOTAL ACCUMULATED DEPRECIATION		0	0	**(102,937)**
217					
222	TOTAL ACCUMULATED AMORTIZATION		0	0	**(3,605)**
224	**TOTAL ACCUMULATED DEPR/AMORT**		**0**	**0**	**(106,542)**
225					
226	NET GAS UTILITY PLANT before DFIT		0	0	**205,672**
227					
228	ACCUMULATED DFIT				
229	ADFIT - Gas Plant in Service		0	0	**(38,265)**
230	ADFIT - Common Plant (282900 from C-DTX)		0	0	**(3,735)**
231	ADFIT - Common Plant (283750 from C-DTX)		0	0	**(24)**
232	ADFIT - Bond Redemptions		0	0	**(536)**
233	ADFIT - Prepaid Pension		0	0	**(2,000)**
234	**TOTAL ACCUMULATED DFIT**		**0**	**0**	**(44,560)**
235					
236	**NET GAS UTILITY PLANT**		**0**	**0**	**161,112**
237					
243	**TOTAL GAS INVENTORY**		**0**	**0**	**3,084**
244					
245	OTHER REGULATORY ASSETS				
246	Prepaid Pension		0	0	**5,710**
247	Working Capital		6,355	0	**6,355**
248	**TOTAL OTHER REGULATORY ASSETS**		**6,355**	**0**	**12,065**
249					
250	**NET RATE BASE**		**6,355**	**0**	**176,261**
251					
252	RATE OF RETURN				**4.54%**
253					
254	**REVENUE REQUIREMENT**		**733**	**78**	**9,957**

AVISTA UTILITIES
OREGON NATURAL GAS
EXHIBIT 1 - 2014 FORECASTED TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description		Forecasted 2014 AMA ROO	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment	Atmos Testing Restate Adjustment	Restated Salaries and Wages Adjustment
	Adjustment Number			3.00	3.01	3.02	3.03	3.04
	Workpaper Refernce			G-UE	G-IP	G-MD	G-AT	G-SW
	REVENUES							
8	SALES TO ULTIMATE CUSTOMERS		96,435	0	0	0	0	0
12	TRANSPORTATION REVENUES		2,923	0	0	0	0	0
19	OTHER OPERATING REVENUES		144	0	0	0	0	0
21	**TOTAL GAS REVENUES**		**99,502**	**0**	**0**	**0**	**0**	**0**
22								
23	**EXPENSES**							
28	TOTAL GAS PURCHASES		55,459	0	0	0	0	0
37	TOTAL OTHER GAS SUPPLY EXPENSE		579	0	0	0	0	0
39	**TOTAL PRODUCTION EXPENSES**		**56,038**	**0**	**0**	**0**	**0**	**0**
40								
45	TOTAL UG STORAGE OPER EXP		112	0	0	0	0	0
48	TOTAL UG STORAGE DEPRCIATION EXP		109	0	0	0	0	0
51	TOTAL UG STORAGE NON-FIT TAXES		7	0	0	0	0	0
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		**228**	**0**	**0**	**0**	**0**	**0**
56								
79	DISTRIBUTION O&M EXPENSES		6,975	0	0	0	168	0
82	TOTAL DISTRIBUTION DEPRCIATION EXP		5,539	0	0	0	0	0
85	TOTAL DISTRIBUTION NON-FIT TAXES		4,896	0	0	0	0	0
89	**TOTAL DISTRIBUTION EXPENSES**		**17,410**	**0**	**0**	**0**	**168**	**0**
90								
97	**CUSTOMER ACCOUNTS OPERATING EXP**		**3,464**	**(43)**	**0**	**0**	**0**	**0**
103	**CUSTOMER SVC & INFO OPERATING EXP**		**567**	**0**	**0**	**0**	**0**	**0**
109	**SALES OPERATING EXPENSES**		**5**	**0**	**0**	**0**	**0**	**0**
110								
123	ADMIN & GENERAL OPERATING EXP		8,379	0	(438)	(40)	0	(98)
126	TOTAL A&G DEPRCIATION EXP		1,424	0	0	0	0	0
131	TOTAL A&G AMRT/NON-FIT TAXES		1,977	0	0	0	0	0
135	**TOTAL ADMIN & GENERAL EXPENSES**		**11,780**	**0**	**(438)**	**(40)**	**0**	**(98)**
136								
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		**0**	**0**	**0**	**0**	**0**	**0**
144								
145	**TOTAL EXPENSES BEFORE FIT**		**89,492**	**(43)**	**(438)**	**(40)**	**168**	**(98)**
146								
147	**NET OPERATING INCOME (LOSS) BEFORE FIT**		**10,010**	**43**	**438**	**40**	**(168)**	**98**
148								
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	(1,430)	14	142	13	(54)	32
152	DEBT INTEREST	2.780%	(289)	0	0	0	0	1
153	DEFERRED INCOME TAX		3,817	0	0	0	0	0
154	STATE INCOME TAXES	7.60%	(85)	3	33	3	(13)	7
155	**GAS NET OPERATING INCOME (LOSS)**		**7,997**	**26**	**263**	**24**	**(101)**	**58**
156								
157	**RATE BASE**							
158	**PLANT IN SERVICE**							
162	TOTAL INTANGIBLE PLANT		13,159	0	0	0	0	0
177	TOTAL UNDERGROUND STORAGE PLANT		6,020	0	0	0	0	0
182	TOTAL PRODUCTION PLANT		8	0	0	0	0	0
195	TOTAL DISTRIBUTION PLANT		268,700	0	0	0	0	(60)
208	TOTAL GAS GENERAL PLANT		24,327	0	0	0	0	0
210	**GROSS PLANT IN SERVICE**		**312,214**	**0**	**0**	**0**	**0**	**(60)**
211								
212	ACCUMULATED DEPRECIATION							
213	Underground Storage		(578)	0	0	0	0	0
214	Distribution Plant		(94,387)	0	0	0	0	0
215	General Plant		(7,972)	0	0	0	0	0
216	TOTAL ACCUMULATED DEPRECIATION		(102,937)	0	0	0	0	0
217								
222	TOTAL ACCUMULATED AMORTIZATION		(3,605)	0	0	0	0	0
224	**TOTAL ACCUMULATED DEPR/AMORT**		**(106,542)**	**0**	**0**	**0**	**0**	**0**
225								
226	NET GAS UTILITY PLANT before DFIT		205,672	0	0	0	0	(60)
227								
228	ACCUMULATED DFIT							
229	ADFIT - Gas Plant in Service		(38,265)	0	0	0	0	0
230	ADFIT - Common Plant (282900 from C-DTX)		(3,735)	0	0	0	0	0
231	ADFIT - Common Plant (283750 from C-DTX)		(24)	0	0	0	0	0
232	ADFIT - Bond Redemptions		(536)	0	0	0	0	0
233	ADFIT - Prepaid Pension		(2,000)	0	0	0	0	0
234	**TOTAL ACCUMULATED DFIT**		**(44,560)**	**0**	**0**	**0**	**0**	**0**
235								
236	**NET GAS UTILITY PLANT**		**161,112**	**0**	**0**	**0**	**0**	**(60)**
237								
243	**TOTAL GAS INVENTORY**		**3,084**	**0**	**0**	**0**	**0**	**0**
244								
245	OTHER REGULATORY ASSETS							
246	Prepaid Pension		5,710	0	0	0	0	0
247	Working Capital		6,355	0	0	0	0	0
248	**TOTAL OTHER REGULATORY ASSETS**		**12,065**	**0**	**0**	**0**	**0**	**0**
249								
250	**NET RATE BASE**		**176,261**	**0**	**0**	**0**	**0**	**(60)**
251								
252	RATE OF RETURN		4.54%					
253								
254	**REVENUE REQUIREMENT**		**9,957**	**(44)**	**(451)**	**(41)**	**173**	**(108)**

AVISTA UTILITIES
OREGON NATURAL GAS
EXHIBIT 1 - 2014 FORECASTED TEST PERIOD
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Description		State Income Tax Adjustment	Restated 2014 AMA Forecasted Test Period
	Adjustment Number		3.05	
	Workpaper Refernce		G-SIT	
	REVENUES			
8	SALES TO ULTIMATE CUSTOMERS		0	96,435
12	TRANSPORTATION REVENUES		0	2,923
19	OTHER OPERATING REVENUES		0	144
21	**TOTAL GAS REVENUES**		0	99,502
22				
23	**EXPENSES**			
28	TOTAL GAS PURCHASES		0	55,459
37	TOTAL OTHER GAS SUPPLY EXPENSE		0	579
39	**TOTAL PRODUCTION EXPENSES**		0	56,038
40				
45	TOTAL UG STORAGE OPER EXP		0	112
48	TOTAL UG STORAGE DEPRCIATION EXP		0	109
51	TOTAL UG STORAGE NON-FIT TAXES		0	7
55	**TOTAL UNDERGROUND STORAGE EXPENSES**		0	228
56				
79	DISTRIBUTION O&M EXPENSES		0	7,143
82	TOTAL DISTRIBUTION DEPRCIATION EXP		0	5,539
85	TOTAL DISTRIBUTION NON-FIT TAXES		0	4,896
89	**TOTAL DISTRIBUTION EXPENSES**		0	17,578
90				
97	**CUSTOMER ACCOUNTS OPERATING EXP**		0	3,421
103	**CUSTOMER SVC & INFO OPERATING EXP**		0	567
109	**SALES OPERATING EXPENSES**		0	5
110				
123	ADMIN & GENERAL OPERATING EXP		0	7,803
126	TOTAL A&G DEPRCIATION EXP		0	1,424
131	TOTAL A&G AMRT/NON-FIT TAXES		0	1,977
135	**TOTAL ADMIN & GENERAL EXPENSES**		0	11,204
136				
143	**TOTAL OTHER DEFERRALS AND AMORTIZATIONS**		0	0
144				
145	**TOTAL EXPENSES BEFORE FIT**		0	89,041
146				
147	**NET OPERATING INCOME (LOSS) BEFORE FIT**		0	10,461
148				
151	FEDERAL INCOME TAX--Normal Accrual	35.00%	1	(1,283)
152	DEBT INTEREST	2.780%	0	(288)
153	DEFERRED INCOME TAX		0	3,817
154	STATE INCOME TAXES	7.60%	(4)	(55)
155	**GAS NET OPERATING INCOME (LOSS)**		3	8,270
156				
157	**RATE BASE**			
158	**PLANT IN SERVICE**			
162	TOTAL INTANGIBLE PLANT		0	13,159
177	TOTAL UNDERGROUND STORAGE PLANT		0	6,020
182	TOTAL PRODUCTION PLANT		0	8
195	TOTAL DISTRIBUTION PLANT		0	268,640
208	TOTAL GAS GENERAL PLANT		0	24,327
210	**GROSS PLANT IN SERVICE**		0	312,154
211				
212	ACCUMULATED DEPRECIATION			
213	Underground Storage		0	(578)
214	Distribution Plant		0	(94,387)
215	General Plant		0	(7,972)
216	TOTAL ACCUMULATED DEPRECIATION		0	(102,937)
217				
222	TOTAL ACCUMULATED AMORTIZATION		0	(3,605)
224	**TOTAL ACCUMULATED DEPR/AMORT**		0	(106,542)
225				
226	NET GAS UTILITY PLANT before DFIT		0	205,612
227				
228	ACCUMULATED DFIT			
229	ADFIT - Gas Plant in Service		0	(38,265)
230	ADFIT - Common Plant (282900 from C-DTX)		0	(3,735)
231	ADFIT - Common Plant (283750 from C-DTX)		0	(24)
232	ADFIT - Bond Redemptions		0	(536)
233	ADFIT - Prepaid Pension		0	(2,000)
234	**TOTAL ACCUMULATED DFIT**		0	(44,560)
235				
236	**NET GAS UTILITY PLANT**		0	161,052
237				
243	**TOTAL GAS INVENTORY**		0	3,084
244				
245	OTHER REGULATORY ASSETS			
246	Prepaid Pension		0	5,710
247	Working Capital		0	6,355
248	**TOTAL OTHER REGULATORY ASSETS**		0	12,065
249				
250	**NET RATE BASE**		0	176,201
251				
252	RATE OF RETURN			4.69%
253				
254	**REVENUE REQUIREMENT**		(5)	9,480

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

ELIZABETH M. ANDREWS
Exhibit No. 602

Revenue Requirement and Allocations

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.		Acct. No.	Description	PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2014 AMA Forecasted Test Period	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Forecasted Proposed Total (AMA)
	REVENUES			a	b	c	d	e
1			SALES OF GAS:					
2	99	480000	Residential	62,400	455	62,855	9,481	72,336
3	99	481200	Commercial	33,022	(871)	32,151	0	32,151
4	99	481300	Industrial-Firm	539	(332)	207	0	207
5	99	481400	Interruptible	494	728	1,222	0	1,222
6	99	484000	Interdepartmental Sales	14	(14)	0	0	0
7	99	499000	Unbilled Revenue	(1,195)	1,195	0	0	0
8			SALES TO ULTIMATE CUSTOMERS	95,274	1,161	96,435	9,481	105,916
9								
10			TRANSPORTATION REVENUES					
11	99	489300	Transportation - Commercial/Industrial	2,888	35	2,923	0	2,923
12			TRANSPORTATION REVENUES	2,888	35	2,923	0	2,923
13								
14			OTHER OPERATING REVENUES:					
15	99	483XXX	Sales For Resale	67,211	(67,211)	0	0	0
16	99	488000	Miscellaneous Service Revenues	141	0	141	0	141
17	99	493000	Other Gas Revenue - Gas Property Rent	1	0	1	0	1
18	99	495XXX	Other Gas Revenues	38	(36)	2	0	2
19			OTHER OPERATING REVENUES	67,391	(67,247)	144	0	144
20								
21	**TOTAL GAS REVENUES**			**165,553**	**(66,051)**	**99,502**	**9,481**	**108,983**
22								
23	EXPENSES							
24			PRODUCTION EXPENSES:					
25								
26			GAS PURCHASES					
27	OR-804	804XXX	Gas Purchases	119,814	(64,355)	55,459	0	55,459
28			TOTAL GAS PURCHASES	119,814	(64,355)	55,459	0	55,459
29								
30			OTHE GAS SUPPLY EXPENSE					
31	OR-805	805XXX	Other Gas Purchases	(389)	389	0	0	0
32	99	807000	Purchased Gas Expenses	0	11	11	0	11
33	OR-808	808XXX	Natural Gas Storage Transactions	578	(576)	2	0	2
34	99	811000	Gas Used for Products Extraction	(485)	485	0	0	0
35	99	813000	Other Gas Expenses	498	23	521	0	521
36	99	813010	Gas Technology Institute (GTI) Expenses	44	1	45	0	45
37			TOTAL OTHER GAS SUPPLY EXPENSE	246	333	579	0	579
38								
39			TOTAL PRODUCTION EXPENSES	120,060	(64,022)	56,038	0	56,038
40								
41			UNDERGROUND STORAGE EXPENSES:					
42	**99**	814000	Supervision & Engineering	0	0	0	0	0
43	**99**	824000	Other Expenses	58	3	61	0	61
44	**99**	837000	Other Equipment	49	2	51	0	51
45			TOTAL UG STORAGE OPER EXP	107	5	112	0	112
46								
47	OR-DEPX		Depreciation Expense-Underground Storage	112	(3)	109	0	109
48			TOTAL UG STORAGE DEPRCIATION EXP	112	(3)	109	0	109
49								
50	OR-OTX		Taxes Other Than FIT-Underground Storage	7	0	7	0	7
51			TOTAL UG STORAGE NON-FIT TAXES	7	0	7	0	7
52								
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	119	(3)	116	0	116
54								
55			TOTAL UNDERGROUND STORAGE EXPENSES	226	2	228	0	228
56								

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.		Acct. No.	Description	PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2014 AMA Forecasted Test Period	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Forecasted Proposed Total (AMA)
57			DISTRIBUTION EXPENSES:					
58			OPERATION					
59	99	870000	Supervision & Engineering	549	29	578	0	578
60	99	871000	Distribution Load Dispatching	0	0	0	0	0
61	99	874000	Mains & Services Expenses	1,211	57	1,268	0	1,268
62	99	875000	Measuring & Reg Sta Exp-General	255	12	267	0	267
63	99	876000	Measuring & Reg Sta Exp-Industrial	2	0	2	0	2
64	99	877000	Measuring & Reg Sta Exp-City Gate	16	0	16	0	16
65	99	878000	Meter & House Regulator Expenses	122	7	129	0	129
66	99	879000	Customer Installation Expenses	1,001	52	1,053	0	1,053
67	99	880000	Other Expenses	917	217	1,134	0	1,134
68	99	881000	Rents	15	1	16	0	16
69								
70			MAINTENANCE					
71	99	885000	Supervision & Engineering	41	2	43	0	43
72	99	887000	Mains	1,267	57	1,324	0	1,324
73	99	889000	Measuring & Reg Sta Exp-General	127	6	133	0	133
74	99	890000	Measuring & Reg Sta Exp-Industrial	33	1	34	0	34
75	99	891000	Measuring & Reg Sta Exp-City Gate	7	0	7	0	7
76	99	892000	Services	467	21	488	0	488
77	99	893000	Meters & House Regulators	446	21	467	0	467
78	99	894000	Other Equipment	176	8	184	0	184
79			DISTRIBUTION O&M EXPENSES	6,652	491	7,143	0	7,143
80								
81	OR-DEPX		Depreciation Expense-Distribution	3,790	1,749	5,539	0	5,539
82			TOTAL DISTRIBUTION DEPRCIATION EXP	3,790	1,749	5,539	0	5,539
83								
84	OR-OTX		Taxes Other Than FIT-Distribution	5,647	(751)	4,896	699	5,595
85			TOTAL DISTRIBUTION NON-FIT TAXES	5,647	(751)	4,896	699	5,595
86								
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	9,437	998	10,435	699	11,134
88								
89			TOTAL DISTRIBUTION EXPENSES	16,089	1,489	17,578	699	18,277
90								
91			CUSTOMER ACCOUNTS EXPENSES:					
92	99	901000	Supervision	154	0	154	0	154
93	99	902000	Meter Reading Expenses	259	12	271	0	271
94	OR-903	903XXX	Customer Records & Collection Expenses	2,283	90	2,373	0	2,373
95	99	904000	Uncollectible Accounts	568	(8)	560	51	611
96	99	905000	Misc Customer Accounts	61	2	63	0	63
97			CUSTOMER ACCOUNTS OPERATING EXP	3,325	96	3,421	51	3,472
98								
99			CUSTOMER SERVICE & INFO EXPENSES:					
100	OR-908	908XXX	Customer Assistance Expenses	2,086	(1,843)	243	0	243
101	99	909000	Advertising	266	9	275	0	275
102	99	910000	Misc Customer Service & Info Exp	47	2	49	0	49
103			CUSTOMER SVC & INFO OPERATING EXP	2,399	(1,832)	567	0	567
104								
105			SALES EXPENSES:					
106	99	912000	Demonstrating & Selling Expenses	5	0	5	0	5
107	99	913000	Advertising	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0
109			SALES OPERATING EXPENSES	5	0	5	0	5

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.		Acct. No.	Description		PRESENT RATES: Per Results of Operations Report	PRESENT RATES: Total Adjustments	PRESENT RATES: Restated 2014 AMA Forecasted Test Period	WITH PROPOSED RATES: Proposed Revenues & Related Exp	WITH PROPOSED RATES: Forecasted Proposed Total (AMA)
110									
111			ADMINISTRATIVE & GENERAL EXPENSES:						
112	99	920000	Salaries		3,352	(141)	3,211	0	3,211
113	99	921000	Office Supplies & Expenses		503	32	535	0	535
114	99	922000	A&G Expenses Transferred		0	0	0	0	0
115	99	923000	Outside Services Employed		1,287	86	1,373	0	1,373
116	99	924000	Property Insurance Premium		127	27	154	0	154
117	99	925XXX	Injuries and Damages		343	37	380	0	380
118	99	926XXX	Employee Pensions and Benefits		85	5	90	0	90
119	99	928000	Regulatory Commission Expenses		759	42	801	24	825
120	99	930000	Miscellaneous General Expenses		384	(13)	371	205	576
121	99	931000	Rents		92	6	98	0	98
122	99	935000	Maintenance of General Plant		743	47	790	0	790
123			ADMIN & GENERAL OPERATING EXP		7,675	128	7,803	229	8,032
124									
125	OR-DEPX		Depreciation Expense-General		1,169	255	1,424	0	1,424
126			TOTAL A&G DEPRCIATION EXP		1,169	255	1,424	0	1,424
127									
128	OR-AMTX		Amortization Expense-General Plant-303000		8	493	501	0	501
129	OR-AMTX		Amortization Expense-Misc IT Intangible Plant-3031XX		745	724	1,469	0	1,469
130	OR-AMTX		Amortization Expense-General Plant-390200, 396200		7	0	7	0	7
131			TOTAL A&G AMRT/NON-FIT TAXES		760	1,217	1,977	0	1,977
132									
133			TOTAL A&G DEPR/AMRT/NON-FIT TAXES		1,929	1,472	3,401	0	3,401
134									
135			TOTAL ADMIN & GENERAL EXPENSES		9,604	1,600	11,204	229	11,433
136									
137			OTHER DEFERRALS AND AMORTIZATIONS:						
138	99	407330	Senate Bill 408		2	(2)	0	0	0
139	99	407408	Senate Bill Unbilled Add-Ons Amortization		156	(156)	0	0	0
140	99	407431	Senate Bill 408 Amortization		(844)	844	0	0	0
141	99	407321	Reg Amort Roseburg/Medford Deferral		200	(200)	0	0	0
142	99	407421	Reg Credit Roseburg/Medford Deferral		(323)	323	0	0	0
143			TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		(809)	809	0	0	0
144									
145	**TOTAL EXPENSES BEFORE FIT**				**150,899**	**(61,858)**	**89,041**	**979**	**90,020**
146									
147		NET OPERATING INCOME (LOSS) BEFORE FIT			14,654	(4,193)	10,461	8,502	18,963
148									
149		FEDERAL INCOME TAX--Normal Accrual		35.00%	72	(1,355)	(1,283)	2,976	1,693
150		DEBT INTEREST		2.780%	0	(288)	(288)	0	(288)
151		DEFERRED INCOME TAX			3,817	0	3,817	0	3,817
152		STATE INCOME TAXES		7.60%	268	(323)	(55)	0	(55)
153		GAS NET OPERATING INCOME (LOSS)			10,497	(2,227)	8,270	5,526	13,796
154									

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.		Acct. No.	Description	PRESENT RATES Per Results of Operations Report	Total Adjustments	Restated 2014 AMA Forecasted Test Period	WITH PROPOSED RATES Proposed Revenues & Related Exp	Forecasted Proposed Total (AMA)
155			RATE BASE					
156			PLANT IN SERVICE					
157			INTANGIBLE PLANT:					
158	99	303000	Misc Intangible Plant (303000)	420	0	420	0	420
159	99	3031XX	Misc Intangible IT Plant (3031XX)	3,841	0	3,841	0	3,841
			Misc Intangible Plant Proforma	0	8,898	8,898	0	8,898
160			TOTAL INTANGIBLE PLANT	4,261	8,898	13,159	0	13,159
161								
162			UNDERGROUND STORAGE PLANT:					
163	99	350100	Land in Fee	0	0	0	0	0
164	99	351100	S & I - Wells	0	0	0	0	0
165	99	351200	S & I - Compress Station	1	0	1	0	1
166	99	351300	S & I - Meas/Regulating Station	0	0	0	0	0
167	99	351400	S & I - Office	19	0	19	0	19
168	99	352000	Wells	2,812	0	2,812	0	2,812
169	99	352100	Wells - Leases	0	0	0	0	0
170	99	353000	Lines	62	0	62	0	62
171	99	354000	Compressor Stn Equipment	2,863	0	2,863	0	2,863
172	99	355000	Meas & Regulating Equipment	6	0	6	0	6
173	99	356000	Purification Equipment	0	0	0	0	0
174	99	357000	Other Equipment	10	0	10	0	10
			Underground Storage Plant Proforma	0	247	247	0	247
175			TOTAL UNDERGROUND STORAGE PLANT	5,773	247	6,020	0	6,020
176								
177			PRODUCTION PLANT:					
178	99	304000	Land & Land Rights	8	0	8	0	8
179	99	311XXX	LPG Equipment	0	0	0	0	0
			Production Plant Proforma	0	0	0	0	0
180			TOTAL PRODUCTION PLANT	8	0	8	0	8
181								
182			DISTRIBUTION PLANT:					
183	99	374200	Land & Land Rights	18	0	18	0	18
184	99	374400	Land Easements	96	0	96	0	96
185	99	375000	Structures & Improvements	267	0	267	0	267
186	99	376000	Mains	139,273	0	139,273	0	139,273
187	99	378000	Measuring & Reg Station Equip-General	4,010	0	4,010	0	4,010
188	99	379000	Measuring & Reg Station Equip-City Gate	1,348	0	1,348	0	1,348
189	99	380000	Services	58,481	0	58,481	0	58,481
190	99	381000	Meters	35,517	0	35,517	0	35,517
191	99	385000	Industrial Measuring & Reg Sta Equip	1,241	0	1,241	0	1,241
192	99	387000	Other Equipment	1	0	1	0	1
			Distribution Plant Proforma	0	28,388	28,388	0	28,388
193			TOTAL DISTRIBUTION PLANT	240,252	28,388	268,640	0	268,640
194								
195			GAS GENERAL PLANT: (From C-GPL)					
196		389XXX	Land & Land Rights	790	0	790	0	790
197		390XXX	Structures & Improvements	8,069	0	8,069	0	8,069
198		391XXX	Office Furniture & Equipment	3,878	0	3,878	0	3,878
199		392XXX	Transportation Equipment	2,448	0	2,448	0	2,448
200		393000	Stores Equipment	57	0	57	0	57
201		394000	Tools, Shop & Garage Equipment	1,777	0	1,777	0	1,777
202		395000	Laboratory Equipment	239	0	239	0	239
203		396XXX	Power Operated Equipment	88	0	88	0	88
204		397XXX	Communications Equipment	2,239	0	2,239	0	2,239
205		398000	Miscellaneous Equipment	34	0	34	0	34
			General Plant Proforma	0	4,708	4,708	0	4,708
206			TOTAL GAS GENERAL PLANT	19,619	4,708	24,327	0	24,327
207								
208			GROSS PLANT IN SERVICE	269,913	42,241	312,154	0	312,154
209								

AVISTA UTILITIES
OREGON NATURAL GAS
PROPOSED RATES EXHIBIT
TWELVE MONTHS ENDED DECEMBER 31, 2014

				PRESENT RATES			WITH PROPOSED RATES	
Line No.		Acct. No.	Description	Per Results of Operations Report	Total Adjustments	Restated 2014 AMA Forecasted Test Period	Proposed Revenues & Related Exp	Forecasted Proposed Total (AMA)
210			ACCUMULATED DEPRECIATION					
211	OR-ADEP		Underground Storage	(354)	(224)	(578)	0	(578)
212	OR-ADEP		Distribution Plant	(86,493)	(7,894)	(94,387)	0	(94,387)
213	OR-ADEP		General Plant	(5,812)	(2,160)	(7,972)	0	(7,972)
214			TOTAL ACCUMULATED DEPRECIATION	(92,659)	(10,278)	(102,937)	0	(102,937)
215								
216			ACCUMULATED AMORTIZATION					
217	OR-AAMT		General Plant - 303000	(45)	0	(45)	0	(45)
218	OR-AAMT		Misc IT Intangible IT Plant - 3031XX	(1,803)	(1,698)	(3,501)	0	(3,501)
219	OR-AAMT		General Plant - 390200, 396200	(59)	0	(59)	0	(59)
220			TOTAL ACCUMULATED AMORTIZATION	(1,907)	(1,698)	(3,605)	0	(3,605)
221								
222			TOTAL ACCUMULATED DEPR/AMORT	(94,566)	(11,976)	(106,542)	0	(106,542)
223								
224			NET GAS UTILITY PLANT before DFIT	175,347	30,265	205,612	0	205,612
225								
226			ACCUMULATED DFIT					
227	99	282900	ADFIT - Gas Plant in Service	(33,625)	(4,640)	(38,265)	0	(38,265)
228		282900	ADFIT - Common Plant (282900 from C-DTX)	(2,681)	(1,054)	(3,735)	0	(3,735)
229		283750	ADFIT - Common Plant (283750 from C-DTX)	(24)	0	(24)	0	(24)
230	99	283850	ADFIT - Bond Redemptions	(536)	0	(536)	0	(536)
231			ADFIT - Prepaid Pension	0	(2,000)	(2,000)	0	(2,000)
232			TOTAL ACCUMULATED DFIT	(36,866)	(7,694)	(44,560)	0	(44,560)
233								
234			NET GAS UTILITY PLANT	138,481	22,571	161,052	0	161,052
235								
236			GAS INVENTORY					
237	99	117100	Gas Stored - Recoverable Base Gas	1,261	0	1,261	0	1,261
238	99	164100	Gas Inventory - Jackson Prairie	1,680	0	1,680	0	1,680
239	99	164105	Gas Inventory - Jackson Prairie Expansion	143	0	143	0	143
240	99	164110	Gas Inventory - Mist	0	0	0	0	0
241			TOTAL GAS INVENTORY	3,084	0	3,084	0	3,084
242								
243			OTHER REGULATORY ASSETS					
244			Prepaid Pension	0	5,710	5,710	0	5,710
245			Working Capital	0	6,355	6,355	0	6,355
246	ER REGULATORY ASS		TOTAL WORKING CAPITAL	0	12,065	12,065	0	12,065
247								
248			NET RATE BASE	141,565	34,636	176,201	0	176,201
249								
250			RATE OF RETURN	7.41%		4.69%		7.83%

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.	Acct.	No.	Description	Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment	Weather Normalization Sales/Purch	Restate Debt Adjustment	Forecast Expense Adjustment	Forecast Revenue Load Adjustment
			Adjustment Number	1.01	1.02	1.03	1.04	1.05	2.00	2.01
			Workpaper Reference	G-FAF	G-MR	G-EAS	G-WN	G-RD	G-FE	G-FR
	REVENUES									
1			SALES OF GAS:							
2	99	480000	Residential	0	0	786	(382)	0	0	51
3	99	481200	Commercial	0	0	762	(174)	0	0	(1,459)
4	99	481300	Industrial-Firm	0	0	16	0	0	0	(348)
5	99	481400	Interruptible	0	0	66	0	0	0	662
6	99	484000	Interdepartmental Sales	0	0	0	0	0	0	(14)
7	99	499000	Unbilled Revenue	0	0	193	0	0	0	1,002
8			SALES TO ULTIMATE CUSTOMERS	0	0	1,823	(556)	0	0	(106)
9										
10			TRANSPORTATION REVENUES							
11	99	489300	Transportation - Commercial/Industrial	0	0	(16)	0	0	0	51
12			TRANSPORTATION REVENUES	0	0	(16)	0	0	0	51
13										
14			OTHER OPERATING REVENUES:							
15	99	483XXX	Sales For Resale	0	0	0	(67,211)	0	0	0
16	99	488000	Miscellaneous Service Revenues	0	0	0	0	0	0	0
17	99	493000	Other Gas Revenue - Gas Property Rent	0	0	0	0	0	0	0
18	99	495XXX	Other Gas Revenues	0	0	(36)	0	0	0	0
19			OTHER OPERATING REVENUES	0	0	(36)	(67,211)	0	0	0
20										
21	**TOTAL GAS REVENUES**			**0**	**0**	**1,771**	**(67,767)**	**0**	**0**	**(55)**
22										
23	**EXPENSES**									
24			PRODUCTION EXPENSES:							
25										
26			GAS PURCHASES							
27	OR-80	804XXX	Gas Purchases	0	0	0	(63,161)	0	0	(1,194)
28			TOTAL GAS PURCHASES	0	0	0	(63,161)	0	0	(1,194)
29										
30			OTHE GAS SUPPLY EXPENSE							
31	OR-80	805XXX	Other Gas Purchases	0	0	4,730	(4,341)	0	0	0
32	99	807000	Purchased Gas Expenses	0	0	0	0	0	0	0
33	OR-80	808XXX	Natural Gas Storage Transactions	0	0	0	(576)	0	0	0
34	99	811000	Gas Used for Products Extraction	0	0	0	485	0	0	0
35	99	813000	Other Gas Expenses	18	0	0	0	0	5	0
36	99	813010	Gas Technology Institute (GTI) Expenses	0	0	0	0	0	0	1
37			TOTAL OTHER GAS SUPPLY EXPENSE	18	0	4,730	(4,432)	0	5	1
38										
39			**TOTAL PRODUCTION EXPENSES**	**18**	**0**	**4,730**	**(67,593)**	**0**	**5**	**(1,193)**
40										
41			UNDERGROUND STORAGE EXPENSES:							
42	**99**	814000	Supervision & Engineering	0	0	0	0	0	0	0
43	**99**	824000	Other Expenses	0	0	0	0	0	3	0
44	**99**	837000	Other Equipment	0	0	0	0	0	2	0
45			TOTAL UG STORAGE OPER EXP	0	0	0	0	0	5	0
46										
47	R-DEPX		Depreciation Expense-Underground Storage	0	0	0	0	0	0	0
48			TOTAL UG STORAGE DEPRCIATION EXP	0	0	0	0	0	0	0
49										
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	0	0	0	0	0	0
51			TOTAL UG STORAGE NON-FIT TAXES	0	0	0	0	0	0	0
52										
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	0	0	0	0	0	0
54										
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**0**	**0**	**0**	**0**	**5**	**0**
56										
57			DISTRIBUTION EXPENSES:							
58			OPERATION							
59	99	870000	Supervision & Engineering	13	0	0	0	0	1	0
60	99	871000	Distribution Load Dispatching	0	0	0	0	0	0	0
61	99	874000	Mains & Services Expenses	2	0	0	0	0	31	0
62	99	875000	Measuring & Reg Sta Exp-General	0	0	0	0	0	3	0
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
65	99	878000	Meter & House Regulator Expenses	0	0	0	0	0	(9)	0
66	99	879000	Customer Installation Expenses	1	0	0	0	0	7	0
67	99	880000	Other Expenses	6	0	0	0	0	13	0
68	99	881000	Rents	0	0	0	0	0	1	0
69										
70			MAINTENANCE							
71	99	885000	Supervision & Engineering	0	0	0	0	0	0	0
72	99	887000	Mains	0	0	0	0	0	32	0
73	99	889000	Measuring & Reg Sta Exp-General	0	0	0	0	0	2	0
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	1	0
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
76	99	892000	Services	0	0	0	0	0	13	0
77	99	893000	Meters & House Regulators	0	0	0	0	0	5	0
78	99	894000	Other Equipment	0	0	0	0	0	3	0
79			DISTRIBUTION O&M EXPENSES	22	0	0	0	0	103	0
80										
81	OR-DEPX		Depreciation Expense-Distribution	0	0	0	0	0	0	0
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	0	0	0	0	0	0
83										
84	OR-OTX		Taxes Other Than FIT-Distribution	0	0	(1,574)	(11)	0	0	(1)
85			TOTAL DISTRIBUTION NON-FIT TAXES	0	0	(1,574)	(11)	0	0	(1)
86										
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	0	0	(1,574)	(11)	0	0	(1)
88										
89			**TOTAL DISTRIBUTION EXPENSES**	**22**	**0**	**(1,574)**	**(11)**	**0**	**103**	**(1)**
90										
91			CUSTOMER ACCOUNTS EXPENSES:							
92	99	901000	Supervision	0	0	0	0	0	0	0
93	99	902000	Meter Reading Expenses	0	0	0	0	0	2	0
94	OR-90	903XXX	Customer Records & Collection Expenses	(2)	0	0	0	0	22	0
95	99	904000	Uncollectible Accounts	(1)	0	13	(3)	0	26	0
96	99	905000	Misc Customer Accounts	0	0	0	0	0	0	0
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**(3)**	**0**	**13**	**(3)**	**0**	**50**	**0**
98										
99			CUSTOMER SERVICE & INFO EXPENSES:							
100	OR-90	908XXX	Customer Assistance Expenses	0	0	(1,848)	0	0	2	0
101	99	909000	Advertising	0	(2)	0	0	0	8	0
102	99	910000	Misc Customer Service & Info Exp	0	0	0	0	0	1	0
103			**CUSTOMER SVC & INFO OPERATING EXP**	**0**	**(2)**	**(1,848)**	**0**	**0**	**11**	**0**
104										
105			SALES EXPENSES:							
106	99	912000	Demonstrating & Selling Expenses	0	0	0	0	0	0	0
107	99	913000	Advertising	0	0	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0	0	0
109			**SALES OPERATING EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
110										
111			ADMINISTRATIVE & GENERAL EXPENSES:							
112	99	920000	Salaries	76	0	0	0	0	57	0
113	99	921000	Office Supplies & Expenses	10	1	0	0	0	20	0
114	99	922000	A&G Expenses Transferred	0	0	0	0	0	0	0
115	99	923000	Outside Services Employed	30	0	0	0	0	56	0
116	99	924000	Property Insurance Premium	3	0	0	0	0	1	0
117	99	925XXX	Injuries and Damages	8	(27)	0	0	0	3	0
118	99	926XXX	Employee Pensions and Benefits	2	0	0	0	0	3	0
119	99	928000	Regulatory Commission Expenses	2	21	9	(2)	0	24	0
120	99	930000	Miscellaneous General Expenses	10	2	0	0	0	14	0

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description		Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment	Weather Normalization Sales/Purch	Restate Debt Adjustment	Forecast Expense Adjustment	Forecast Revenue Load Adjustment
			Adjustment Number		**1.01**	**1.02**	**1.03**	**1.04**	**1.05**	**2.00**	**2.01**
			Workpaper Reference		**G-FAF**	**G-MR**	**G-EAS**	**G-WN**	**G-RD**	**G-FE**	**G-FR**
121	99	931000	Rents		2	0	0	0	0	4	0
122	99	935000	Maintenance of General Plant		14	1	0	0	0	28	0
123			ADMIN & GENERAL OPERATING EXP		157	(2)	9	(2)	0	210	0
124											
125	OR-DEPX		Depreciation Expense-General		0	0	0	0	0	0	0
126			TOTAL A&G DEPRCIATION EXP		0	0	0	0	0	0	0
127											
128	OR-AMTX		Amortization Expense-General Plant-303000		0	0	0	0	0	0	0
129	OR-AMTX		Amortization Expense-Misc IT Intangible Plant-3031XX		0	0	0	0	0	0	0
130	OR-AMTX		Amortization Expense-General Plant-390200, 396200		0	0	0	0	0	0	0
131			TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	0	0	0	0
132											
133			TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	0	0	0	0	0	0
134											
135			**TOTAL ADMIN & GENERAL EXPENSES**		**157**	**(2)**	**9**	**(2)**	**0**	**210**	**0**
136											
137			OTHER DEFERRALS AND AMORTIZATIONS:								
138	99	407330	Senate Bill 408		0	0	(2)	0	0	0	0
139	99	407408	Senate Bill Unbilled Add-Ons Amortization		0	0	(156)	0	0	0	0
140	99	407431	Senate Bill 408 Amortization		0	0	844	0	0	0	0
141	99	407321	Reg Amort Roseburg/Medford Deferral		0	0	(200)	0	0	0	0
142	99	407421	Reg Credit Roseburg/Medford Deferral		0	0	323	0	0	0	0
143			TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	0	809	0	0	0	0
144											
145	**TOTAL EXPENSES BEFORE FIT**				**194**	**(4)**	**2,139**	**(67,609)**	**0**	**384**	**(1,194)**
146											
147			**NET OPERATING INCOME (LOSS) BEFORE FIT**		**(194)**	**4**	**(368)**	**(158)**	**0**	**(384)**	**1,139**
148											
151			FEDERAL INCOME TAX--Normal Accrual	35.00%	(63)	1	(119)	(51)	0	(124)	368
152			DEBT INTEREST	2.780%	0	0	0	0	96	0	0
153			DEFERRED INCOME TAX			0	0	0	0	0	0
154			STATE INCOME TAXES	7.60%	(15)	0	(28)	(12)	0	(29)	87
155			GAS NET OPERATING INCOME (LOSS)		(117)	2	(221)	(95)	(96)	(231)	684
156											
157			RATE BASE								
158			PLANT IN SERVICE								
159			INTANGIBLE PLANT:								
160	99	303000	Misc Intangible Plant (303000)		0	0	0	0	0	0	0
161	99	3031XX	Misc Intangible IT Plant (3031XX)		0	0	0	0	0	0	0
			Misc Intangible Plant Proforma		0	0	0	0	0	0	0
162			TOTAL INTANGIBLE PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
163											
164			UNDERGROUND STORAGE PLANT:								
165	99	350100	Land in Fee		0	0	0	0	0	0	0
166	99	351100	S & I - Wells		0	0	0	0	0	0	0
167	99	351200	S & I - Compress Station		0	0	0	0	0	0	0
168	99	351300	S & I - Meas/Regulating Station		0	0	0	0	0	0	0
169	99	351400	S & I - Office		0	0	0	0	0	0	0
170	99	352000	Wells		0	0	0	0	0	0	0
171	99	352100	Wells - Leases		0	0	0	0	0	0	0
172	99	353000	Lines		0	0	0	0	0	0	0
173	99	354000	Compressor Stn Equipment		0	0	0	0	0	0	0
174	99	355000	Meas & Regulating Equipment		0	0	0	0	0	0	0
175	99	356000	Purification Equipment		0	0	0	0	0	0	0
176	99	357000	Other Equipment		0	0	0	0	0	0	0
			Underground Storage Plant Proforma		0	0	0	0	0	0	0
177			TOTAL UNDERGROUND STORAGE PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
178											
179			PRODUCTION PLANT:								
180	99	304000	Land & Land Rights		0	0	0	0	0	0	0
181	99	311XXX	LPG Equipment		0	0	0	0	0	0	0
			Production Plant Proforma		0	0	0	0	0	0	0
182			TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
183											
184			DISTRIBUTION PLANT:								
185	99	374200	Land & Land Rights		0	0	0	0	0	0	0
186	99	374400	Land Easements		0	0	0	0	0	0	0
187	99	375000	Structures & Improvements		0	0	0	0	0	0	0
188	99	376000	Mains		0	0	0	0	0	0	0
189	99	378000	Measuring & Reg Station Equip-General		0	0	0	0	0	0	0
190	99	379000	Measuring & Reg Station Equip-City Gate		0	0	0	0	0	0	0
191	99	380000	Services		0	0	0	0	0	0	0
192	99	381000	Meters		0	0	0	0	0	0	0
193	99	385000	Industrial Measuring & Reg Sta Equip		0	0	0	0	0	0	0
194	99	387000	Other Equipment		0	0	0	0	0	0	0
			Distribution Plant Proforma		0	0	0	0	0	0	0
195			TOTAL DISTRIBUTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
196											
197			GAS GENERAL PLANT: (From C-GPL)								
198		389XXX	Land & Land Rights		0	0	0	0	0	0	0
199		390XXX	Structures & Improvements		0	0	0	0	0	0	0
200		391XXX	Office Furniture & Equipment		0	0	0	0	0	0	0
201		392XXX	Transportation Equipment		0	0	0	0	0	0	0
202		393000	Stores Equipment		0	0	0	0	0	0	0
203		394000	Tools, Shop & Garage Equipment		0	0	0	0	0	0	0
204		395000	Laboratory Equipment		0	0	0	0	0	0	0
205		396XXX	Power Operated Equipment		0	0	0	0	0	0	0
206		397XXX	Communications Equipment		0	0	0	0	0	0	0
207		398000	Miscellaneous Equipment		0	0	0	0	0	0	0
			General Plant Proforma		0	0	0	0	0	0	0
208			TOTAL GAS GENERAL PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
209											
210			**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
211											
212			ACCUMULATED DEPRECIATION								
213	R-ADEP		Underground Storage		0	0	0	0	0	0	0
214	R-ADEP		Distribution Plant		0	0	0	0	0	0	0
215	R-ADEP		General Plant		0	0	0	0	0	0	0
216			TOTAL ACCUMULATED DEPRECIATION		0	0	0	0	0	0	0
217											
218			ACCUMULATED AMORTIZATION								
219	R-AAMT		General Plant - 303000		0	0	0	0	0	0	0
220	R-AAMT		Misc IT Intangible IT Plant - 3031XX		0	0	0	0	0	0	0
221	R-AAMT		General Plant - 390200, 396200		0	0	0	0	0	0	0
222			TOTAL ACCUMULATED AMORTIZATION		0	0	0	0	0	0	0
223											
224			TOTAL ACCUMULATED DEPR/AMORT		0	0	0	0	0	0	0
225											
226			NET GAS UTILITY PLANT before DFIT		0	0	0	0	0	0	0
227											
228			ACCUMULATED DFIT								
229	99	282900	ADFIT - Gas Plant in Service		0	0	0	0	0	0	0
230		282900	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	0	0	0	0
231		283750	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0	0	0	0
232	99	283850	ADFIT - Bond Redemptions		0	0	0	0	0	0	0
233			ADFIT - Prepaid Pension		0	0	0	0	0	0	0
234			**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
235											
236			**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description		Allocation Factor Adjustment	Miscellaneous Restating Adjustment	Eliminate Adder Schedule Adjustment	Weather Normalization Sales/Purch	Restate Debt Adjustment	Forecast Expense Adjustment	Forecast Revenue Load Adjustment
			Adjustment Number		**1.01**	**1.02**	**1.03**	**1.04**	**1.05**	**2.00**	**2.01**
			Workpaper Reference		**G-FAF**	**G-MR**	**G-EAS**	**G-WN**	**G-RD**	**G-FE**	**G-FR**
237											
238			GAS INVENTORY								
239	99	117100	Gas Stored - Recoverable Base Gas		0	0	0	0	0	0	0
240	99	164100	Gas Inventory - Jackson Prairie		0	0	0	0	0	0	0
241	99	164105	Gas Inventory - Jackson Prairie Expansion		0	0	0	0	0	0	0
242	99	164110	Gas Inventory - Mist		0	0	0	0	0	0	0
243			**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
244											
245			OTHER REGULATORY ASSETS								
246			Prepaid Pension		0	0	0	0	0	0	0
247			Working Capital		0	0	0	0	0	0	0
248			**TOTAL OTHER REGULATORY ASSETS**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
249											
250			**NET RATE BASE**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
251											
252			**RATE OF RETURN**		**0%**						
253											
254			**REVENUE REQUIREMENT**		**200**	**-4**	**379**	**163**	**165**	**396**	**-1,174**
255											
256			Pro Forma Rate of Return	7.83%							
257			Revenue Conversion Factor	0.58293							
258											
259			NOI Requirement		**117**	**-2**	**221**	**95**	**96**	**231**	**-684**
260			Revenue Requirement		**200**	**-4**	**379**	**163**	**165**	**396**	**-1,174**
261											
262			TAX CALCULATION:								
263			Net Operating Income		(194)	4	(368)	(158)	-	(384)	1,139
264			Other Deductions								
265			Interest		-	-	-	-	-	-	-
266			Net Schedule M Adjustments		-	-	-	-	-	-	-
267			Income Before Tax		(194)	4	(368)	(158)	-	(384)	1,139
268											
269			State Income Taxes		(15)	0	(28)	(12)	-	(29)	87
270			Taxable Income		(179)	4	(340)	(146)	-	(355)	1,052
271											
272			Federal Tax		(63)	1	(119)	(51)	-	(124)	368
273			Net Operating Income		(117)	2	(221)	(95)	-	(231)	684
270											
271			FOR INFORMATION ONLY:								
272			SIT Debt Interest		0	0	0	0	0	0	0
273			FIT Debt Interest		0	0	0	0	0	0	0
274					0	0	0	0	0	0	0

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
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Line No.		Acct. No.	Description	Forecast Labor & Benefits Adjustment	Forecast VSIP Amort Adjustment	Forecast Property Tax Adjustment	2012 Capital Activity Adjustment	2013 Capital Activity Adjustment	2014 Capital Activity Adjustment	Depreciation Study Adjustment
			Adjustment Number	2.02	2.03	2.04	2.05	2.06	2.07	2.08
			Workpaper Reference	G-FLB	G-VSIP	G-FPT	G-CAP12	G-CAP13	G-CAP14	G-DEPR
	REVENUES									
1			SALES OF GAS:							
2	99	480000	Residential	0	0	0	0	0	0	0
3	99	481200	Commercial	0	0	0	0	0	0	0
4	99	481300	Industrial-Firm	0	0	0	0	0	0	0
5	99	481400	Interruptible	0	0	0	0	0	0	0
6	99	484000	Interdepartmental Sales	0	0	0	0	0	0	0
7	99	499000	Unbilled Revenue	0	0	0	0	0	0	0
8			SALES TO ULTIMATE CUSTOMERS	0	0	0	0	0	0	0
9										
10			TRANSPORTATION REVENUES							
11	99	489300	Transportation - Commercial/Industrial	0	0	0	0	0	0	0
12			TRANSPORTATION REVENUES	0	0	0	0	0	0	0
13										
14			OTHER OPERATING REVENUES:							
15	99	483XXX	Sales For Resale	0	0	0	0	0	0	0
16	99	488000	Miscellaneous Service Revenues	0	0	0	0	0	0	0
17	99	493000	Other Gas Revenue - Gas Property Rent	0	0	0	0	0	0	0
18	99	495XXX	Other Gas Revenues	0	0	0	0	0	0	0
19			OTHER OPERATING REVENUES	0	0	0	0	0	0	0
20										
21	**TOTAL GAS REVENUES**			**0**	**0**	**0**	**0**	**0**	**0**	**0**
22										
23	**EXPENSES**									
24			PRODUCTION EXPENSES:							
25										
26			GAS PURCHASES							
27	OR-80	804XXX	Gas Purchases	0	0	0	0	0	0	0
28			TOTAL GAS PURCHASES	0	0	0	0	0	0	0
29										
30			OTHE GAS SUPPLY EXPENSE							
31	OR-80	805XXX	Other Gas Purchases	0	0	0	0	0	0	0
32	99	807000	Purchased Gas Expenses	11	0	0	0	0	0	0
33	OR-80	808XXX	Natural Gas Storage Transactions	0	0	0	0	0	0	0
34	99	811000	Gas Used for Products Extraction	0	0	0	0	0	0	0
35	99	813000	Other Gas Expenses	0	0	0	0	0	0	0
36	99	813010	Gas Technology Institute (GTI) Expenses	0	0	0	0	0	0	0
37			TOTAL OTHER GAS SUPPLY EXPENSE	11	0	0	0	0	0	0
38										
39			**TOTAL PRODUCTION EXPENSES**	**11**	**0**	**0**	**0**	**0**	**0**	**0**
40										
41			UNDERGROUND STORAGE EXPENSES:							
42	**99**	814000	Supervision & Engineering	0	0	0	0	0	0	0
43	**99**	824000	Other Expenses	0	0	0	0	0	0	0
44	**99**	837000	Other Equipment	0	0	0	0	0	0	0
45			TOTAL UG STORAGE OPER EXP	0	0	0	0	0	0	0
46										
47	R-DEPX		Depreciation Expense-Underground Storage	0	0	0	1	2	1	(7)
48			TOTAL UG STORAGE DEPRCIATION EXP	0	0	0	1	2	1	(7)
49										
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	0	0	0	0	0	0
51			TOTAL UG STORAGE NON-FIT TAXES	0	0	0	0	0	0	0
52										
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	0	0	1	2	1	(7)
54										
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**0**	**0**	**1**	**2**	**1**	**(7)**
56										
57			DISTRIBUTION EXPENSES:							
58			OPERATION							
59	99	870000	Supervision & Engineering	15	0	0	0	0	0	0
60	99	871000	Distribution Load Dispatching	0	0	0	0	0	0	0
61	99	874000	Mains & Services Expenses	24	0	0	0	0	0	0
62	99	875000	Measuring & Reg Sta Exp-General	9	0	0	0	0	0	0
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
65	99	878000	Meter & House Regulator Expenses	16	0	0	0	0	0	0
66	99	879000	Customer Installation Expenses	44	0	0	0	0	0	0
67	99	880000	Other Expenses	30	0	0	0	0	0	0
68	99	881000	Rents	0	0	0	0	0	0	0
69										
70			MAINTENANCE							
71	99	885000	Supervision & Engineering	2	0	0	0	0	0	0
72	99	887000	Mains	25	0	0	0	0	0	0
73	99	889000	Measuring & Reg Sta Exp-General	4	0	0	0	0	0	0
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
76	99	892000	Services	8	0	0	0	0	0	0
77	99	893000	Meters & House Regulators	16	0	0	0	0	0	0
78	99	894000	Other Equipment	5	0	0	0	0	0	0
79			DISTRIBUTION O&M EXPENSES	198	0	0	0	0	0	0
80										
81	OR-DEPX		Depreciation Expense-Distribution	0	0	0	45	272	127	1,305
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	0	0	45	272	127	1,305
83										
84	OR-OTX		Taxes Other Than FIT-Distribution	0	0	200	62	367	206	0
85			TOTAL DISTRIBUTION NON-FIT TAXES	0	0	200	62	367	206	0
86										
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	0	0	200	107	639	333	1,305
88										
89			**TOTAL DISTRIBUTION EXPENSES**	**198**	**0**	**200**	**107**	**639**	**333**	**1,305**
90										
91			CUSTOMER ACCOUNTS EXPENSES:							
92	99	901000	Supervision	0	0	0	0	0	0	0
93	99	902000	Meter Reading Expenses	10	0	0	0	0	0	0
94	OR-90	903XXX	Customer Records & Collection Expenses	70	0	0	0	0	0	0
95	99	904000	Uncollectible Accounts	0	0	0	0	0	0	0
96	99	905000	Misc Customer Accounts	2	0	0	0	0	0	0
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**82**	**0**	**0**	**0**	**0**	**0**	**0**
98										
99			CUSTOMER SERVICE & INFO EXPENSES:							
100	OR-90	908XXX	Customer Assistance Expenses	3	0	0	0	0	0	0
101	99	909000	Advertising	3	0	0	0	0	0	0
102	99	910000	Misc Customer Service & Info Exp	1	0	0	0	0	0	0
103			**CUSTOMER SVC & INFO OPERATING EXP**	**7**	**0**	**0**	**0**	**0**	**0**	**0**
104										
105			SALES EXPENSES:							
106	99	912000	Demonstrating & Selling Expenses	0	0	0	0	0	0	0
107	99	913000	Advertising	0	0	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0	0	0
109			**SALES OPERATING EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
110										
111			ADMINISTRATIVE & GENERAL EXPENSES:							
112	99	920000	Salaries	79	183	0	0	0	0	0
113	99	921000	Office Supplies & Expenses	1	0	0	0	0	0	0
114	99	922000	A&G Expenses Transferred	0	0	0	0	0	0	0
115	99	923000	Outside Services Employed	0	0	0	0	0	0	0
116	99	924000	Property Insurance Premium	0	0	0	0	0	0	0
117	99	925XXX	Injuries and Damages	0	0	0	0	0	0	0
118	99	926XXX	Employee Pensions and Benefits	0	0	0	0	0	0	0
119	99	928000	Regulatory Commission Expenses	(12)	0	0	0	0	0	0
120	99	930000	Miscellaneous General Expenses	1	0	0	0	0	0	0

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description		Forecast Labor & Benefits Adjustment	Forecast VSIP Amort Adjustment	Forecast Property Tax Adjustment	2012 Capital Activity Adjustment	2013 Capital Activity Adjustment	2014 Capital Activity Adjustment	Depreciation Study Adjustment
			Adjustment Number		2.02	2.03	2.04	2.05	2.06	2.07	2.08
			Workpaper Reference		G-FLB	G-VSIP	G-FPT	G-CAP12	G-CAP13	G-CAP14	G-DEPR
121	99	931000	Rents		0	0	0	0	0	0	0
122	99	935000	Maintenance of General Plant		4	0	0	0	0	0	0
123			ADMIN & GENERAL OPERATING EXP		73	183	0	0	0	0	0
124											
125	OR-DEPX		Depreciation Expense-General		0	0	0	1	28	0	226
126			TOTAL A&G DEPRCIATION EXP		0	0	0	1	28	0	226
127											
128	OR-AMTX		Amortization Expense-General Plant-303000		0	0	0	(4)	276	73	148
129	OR-AMTX		Amortization Expense-Misc IT Intangible Plant-3031XX		0	0	0	79	157	455	33
130	OR-AMTX		Amortization Expense-General Plant-390200, 396200		0	0	0	0	0	0	0
131			TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	75	433	528	181
132											
133			TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	0	0	76	461	528	407
134											
135			**TOTAL ADMIN & GENERAL EXPENSES**		**73**	**183**	**0**	**76**	**461**	**528**	**407**
136											
137			OTHER DEFERRALS AND AMORTIZATIONS:								
138	99	407330	Senate Bill 408		0	0	0	0	0	0	0
139	99	407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0	0	0	0	0
140	99	407431	Senate Bill 408 Amortization		0	0	0	0	0	0	0
141	99	407321	Reg Amort Roseburg/Medford Deferral		0	0	0	0	0	0	0
142	99	407421	Reg Credit Roseburg/Medford Deferral		0	0	0	0	0	0	0
143			TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	0	0	0	0	0	0
144											
145	**TOTAL EXPENSES BEFORE FIT**				**371**	**183**	**200**	**184**	**1,102**	**862**	**1,705**
146											
147			**NET OPERATING INCOME (LOSS) BEFORE FIT**		**(371)**	**(183)**	**(200)**	**(184)**	**(1,102)**	**(862)**	**(1,705)**
148											
151			FEDERAL INCOME TAX--Normal Accrual	35.00%	(120)	(59)	(65)	(60)	(356)	(279)	(551)
152			DEBT INTEREST	2.780%	(41)	0	0	(18)	(174)	(93)	11
153			DEFERRED INCOME TAX		0	0	0	0	0	0	0
154			STATE INCOME TAXES	7.60%	(28)	(14)	(15)	(14)	(84)	(66)	(130)
155			GAS NET OPERATING INCOME (LOSS)		(182)	(110)	(120)	(93)	(488)	(425)	(1,035)
156											
157			RATE BASE								
158			PLANT IN SERVICE								
159			INTANGIBLE PLANT:								
160	99	303000	Misc Intangible Plant (303000)		0	0	0	0	0	0	0
161	99	3031XX	Misc Intangible IT Plant (3031XX)		0	0	0	0	0	0	0
			Misc Intangible Plant Proforma		0	0	0	412	1,902	6,584	0
162			TOTAL INTANGIBLE PLANT		**0**	**0**	**0**	**412**	**1,902**	**6,584**	**0**
163											
164			UNDERGROUND STORAGE PLANT:								
165	99	350100	Land in Fee		0	0	0	0	0	0	0
166	99	351100	S & I - Wells		0	0	0	0	0	0	0
167	99	351200	S & I - Compress Station		0	0	0	0	0	0	0
168	99	351300	S & I - Meas/Regulating Station		0	0	0	0	0	0	0
169	99	351400	S & I - Office		0	0	0	0	0	0	0
170	99	352000	Wells		0	0	0	0	0	0	0
171	99	352100	Wells - Leases		0	0	0	0	0	0	0
172	99	353000	Lines		0	0	0	0	0	0	0
173	99	354000	Compressor Stn Equipment		0	0	0	0	0	0	0
174	99	355000	Meas & Regulating Equipment		0	0	0	0	0	0	0
175	99	356000	Purification Equipment		0	0	0	0	0	0	0
176	99	357000	Other Equipment		0	0	0	0	0	0	0
			Underground Storage Plant Proforma		0	0	0	31	138	78	0
177			TOTAL UNDERGROUND STORAGE PLANT		**0**	**0**	**0**	**31**	**138**	**78**	**0**
178											
179			PRODUCTION PLANT:								
180	99	304000	Land & Land Rights		0	0	0	0	0	0	0
181	99	311XXX	LPG Equipment		0	0	0	0	0	0	0
			Production Plant Proforma		0	0	0	0	0	0	0
182			TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
183											
184			DISTRIBUTION PLANT:								
185	99	374200	Land & Land Rights		0	0	0	0	0	0	0
186	99	374400	Land Easements		0	0	0	0	0	0	0
187	99	375000	Structures & Improvements		0	0	0	0	0	0	0
188	99	376000	Mains		0	0	0	0	0	0	0
189	99	378000	Measuring & Reg Station Equip-General		0	0	0	0	0	0	0
190	99	379000	Measuring & Reg Station Equip-City Gate		0	0	0	0	0	0	0
191	99	380000	Services		0	0	0	0	0	0	0
192	99	381000	Meters		0	0	0	0	0	0	0
193	99	385000	Industrial Measuring & Reg Sta Equip		0	0	0	0	0	0	0
194	99	387000	Other Equipment		0	0	0	0	0	0	0
			Distribution Plant Proforma		0	0	0	2,977	19,099	6,372	0
195			TOTAL DISTRIBUTION PLANT		**0**	**0**	**0**	**2,977**	**19,099**	**6,372**	**0**
196											
197			GAS GENERAL PLANT: (From C-GPL)								
198		389XXX	Land & Land Rights		0	0	0	0	0	0	0
199		390XXX	Structures & Improvements		0	0	0	0	0	0	0
200		391XXX	Office Furniture & Equipment		0	0	0	0	0	0	0
201		392XXX	Transportation Equipment		0	0	0	0	0	0	0
202		393000	Stores Equipment		0	0	0	0	0	0	0
203		394000	Tools, Shop & Garage Equipment		0	0	0	0	0	0	0
204		395000	Laboratory Equipment		0	0	0	0	0	0	0
205		396XXX	Power Operated Equipment		0	0	0	0	0	0	0
206		397XXX	Communications Equipment		0	0	0	0	0	0	0
207		398000	Miscellaneous Equipment		0	0	0	0	0	0	0
			General Plant Proforma		0	0	0	701	3,298	709	0
208			TOTAL GAS GENERAL PLANT		**0**	**0**	**0**	**701**	**3,298**	**709**	**0**
209											
210			**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**4,121**	**24,437**	**13,743**	**0**
211											
212			ACCUMULATED DEPRECIATION								
213	R-ADEP		Underground Storage		0	0	0	(56)	(114)	(58)	4
214	R-ADEP		Distribution Plant		0	0	0	(1,098)	(3,995)	(2,148)	(653)
215	R-ADEP		General Plant		0	0	0	7	(1,301)	(792)	(74)
216			TOTAL ACCUMULATED DEPRECIATION		0	0	0	(1,147)	(5,410)	(2,998)	(723)
217											
218			ACCUMULATED AMORTIZATION								
219	R-AAMT		General Plant - 303000		0	0	0	0	0	0	0
220	R-AAMT		Misc IT Intangible IT Plant - 3031XX		0	0	0	(4)	(926)	(751)	(17)
221	R-AAMT		General Plant - 390200, 396200		0	0	0	0	0	0	0
222			TOTAL ACCUMULATED AMORTIZATION		0	0	0	(4)	(926)	(751)	(17)
223											
224			TOTAL ACCUMULATED DEPR/AMORT		0	0	0	(1,151)	(6,336)	(3,749)	(740)
225											
226			NET GAS UTILITY PLANT before DFIT		0	0	0	2,970	18,101	9,994	(740)
227											
228			ACCUMULATED DFIT								
229	99	282900	ADFIT - Gas Plant in Service		0	0	0	(1,222)	(2,138)	(1,043)	(237)
230		282900	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	(171)	(291)	(570)	(22)
231		283750	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0	0	0	0
232	99	283850	ADFIT - Bond Redemptions		0	0	0	0	0	0	0
233			ADFIT - Prepaid Pension		(2,000)	0	0	0	0	0	0
234			**TOTAL ACCUMULATED DFIT**		**(2,000)**	**0**	**0**	**(1,393)**	**(2,429)**	**(1,613)**	**(259)**
235											
236			**NET GAS UTILITY PLANT**		**(2,000)**	**0**	**0**	**1,577**	**15,672**	**8,381**	**(999)**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description		Forecast Labor & Benefits Adjustment	Forecast VSIP Amort Adjustment	Forecast Property Tax Adjustment	2012 Capital Activity Adjustment	2013 Capital Activity Adjustment	2014 Capital Activity Adjustment	Depreciation Study Adjustment
			Adjustment Number		2.02	2.03	2.04	2.05	2.06	2.07	2.08
			Workpaper Reference		G-FLB	G-VSIP	G-FPT	G-CAP12	G-CAP13	G-CAP14	G-DEPR
237											
238			GAS INVENTORY								
239	99	117100	Gas Stored - Recoverable Base Gas		0	0	0	0	0	0	0
240	99	164100	Gas Inventory - Jackson Prairie		0	0	0	0	0	0	0
241	99	164105	Gas Inventory - Jackson Prairie Expansion		0	0	0	0	0	0	0
242	99	164110	Gas Inventory - Mist		0	0	0	0	0	0	0
243			**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
244											
245			OTHER REGULATORY ASSETS								
246			Prepaid Pension		5,710	0	0	0	0	0	0
247			Working Capital		0	0	0	0	0	0	0
248			**TOTAL OTHER REGULATORY ASSETS**		**5,710**	**0**	**0**	**0**	**0**	**0**	**0**
249											
250			**NET RATE BASE**		**3,710**	**0**	**0**	**1,577**	**15,672**	**8,381**	**(999)**
251											
252			**RATE OF RETURN**								
253											
254			**REVENUE REQUIREMENT**		**810**	**189**	**206**	**371**	**2,942**	**1,854**	**1,642**
255											
256			Pro Forma Rate of Return	7.83%							
257			Revenue Conversion Factor	0.58293							
258											
259			NOI Requirement		**472**	**110**	**120**	**216**	**1,715**	**1,081**	**957**
260			Revenue Requirement		**810**	**189**	**206**	**371**	**2,942**	**1,854**	**1,642**
261											
262			TAX CALCULATION:								
263			Net Operating Income		(371)	(183)	(200)	(184)	(1,102)	(862)	(1,705)
264			Other Deductions								
265			Interest		(103)	-	-	(44)	(436)	(233)	28
266			Net Schedule M Adjustments		-	-	-	-	-	-	-
267			Income Before Tax		(474)	(183)	(200)	(228)	(1,538)	(1,095)	(1,677)
268											
269			State Income Taxes		(36)	(14)	(15)	(17)	(117)	(83)	(127)
270			Taxable Income		(438)	(169)	(185)	(211)	(1,421)	(1,012)	(1,550)
271											
272			Federal Tax		(153)	(59)	(65)	(74)	(497)	(354)	(542)
273			Net Operating Income		(285)	(110)	(120)	(137)	(924)	(658)	(1,007)
270											
271			FOR INFORMATION ONLY:								
272			SIT Debt Interest		8	0	0	3	33	18	-2
273			FIT Debt Interest		33	0	0	14	141	75	-9
274					41	0	0	18	174	93	-11

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description	Working Capital Adjustment	Forecast Insurance Adjustment	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment	Atmos Testing Restate Adjustment	Restated Salaries and Wages Adjustment
			Adjustment Number	2.09	2.10	3.00	3.01	3.02	3.03	3.04
			Workpaper Reference	G-FWC	G-IA	G-UE	G-IP	G-MD	G-AT	G-SW
	REVENUES									
1			SALES OF GAS:							
2	99	480000	Residential	0	0	0	0	0	0	0
3	99	481200	Commercial	0	0	0	0	0	0	0
4	99	481300	Industrial-Firm	0	0	0	0	0	0	0
5	99	481400	Interruptible	0	0	0	0	0	0	0
6	99	484000	Interdepartmental Sales	0	0	0	0	0	0	0
7	99	499000	Unbilled Revenue	0	0	0	0	0	0	0
8			SALES TO ULTIMATE CUSTOMERS	0	0	0	0	0	0	0
9										
10			TRANSPORTATION REVENUES							
11	99	489300	Transportation - Commercial/Industrial	0	0	0	0	0	0	0
12			TRANSPORTATION REVENUES	0	0	0	0	0	0	0
13										
14			OTHER OPERATING REVENUES:							
15	99	483XXX	Sales For Resale	0	0	0	0	0	0	0
16	99	488000	Miscellaneous Service Revenues	0	0	0	0	0	0	0
17	99	493000	Other Gas Revenue - Gas Property Rent	0	0	0	0	0	0	0
18	99	495XXX	Other Gas Revenues	0	0	0	0	0	0	0
19			OTHER OPERATING REVENUES	0	0	0	0	0	0	0
20										
21	**TOTAL GAS REVENUES**			**0**	**0**	**0**	**0**	**0**	**0**	**0**
22										
23	**EXPENSES**									
24			PRODUCTION EXPENSES:							
25										
26			GAS PURCHASES							
27	OR-80	804XXX	Gas Purchases	0	0	0	0	0	0	0
28			TOTAL GAS PURCHASES	0	0	0	0	0	0	0
29										
30			OTHE GAS SUPPLY EXPENSE							
31	OR-80	805XXX	Other Gas Purchases	0	0	0	0	0	0	0
32	99	807000	Purchased Gas Expenses	0	0	0	0	0	0	0
33	OR-80	808XXX	Natural Gas Storage Transactions	0	0	0	0	0	0	0
34	99	811000	Gas Used for Products Extraction	0	0	0	0	0	0	0
35	99	813000	Other Gas Expenses	0	0	0	0	0	0	0
36	99	813010	Gas Technology Institute (GTI) Expenses	0	0	0	0	0	0	0
37			TOTAL OTHER GAS SUPPLY EXPENSE	0	0	0	0	0	0	0
38										
39			**TOTAL PRODUCTION EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
40										
41			UNDERGROUND STORAGE EXPENSES:							
42	**99**	814000	Supervision & Engineering	0	0	0	0	0	0	0
43	**99**	824000	Other Expenses	0	0	0	0	0	0	0
44	**99**	837000	Other Equipment	0	0	0	0	0	0	0
45			TOTAL UG STORAGE OPER EXP	0	0	0	0	0	0	0
46										
47	R-DEPX		Depreciation Expense-Underground Storage	0	0	0	0	0	0	0
48			TOTAL UG STORAGE DEPRCIATION EXP	0	0	0	0	0	0	0
49										
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	0	0	0	0	0	0
51			TOTAL UG STORAGE NON-FIT TAXES	0	0	0	0	0	0	0
52										
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	0	0	0	0	0	0
54										
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
56										
57			DISTRIBUTION EXPENSES:							
58			OPERATION							
59	99	870000	Supervision & Engineering	0	0	0	0	0	0	0
60	99	871000	Distribution Load Dispatching	0	0	0	0	0	0	0
61	99	874000	Mains & Services Expenses	0	0	0	0	0	0	0
62	99	875000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	0
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
65	99	878000	Meter & House Regulator Expenses	0	0	0	0	0	0	0
66	99	879000	Customer Installation Expenses	0	0	0	0	0	0	0
67	99	880000	Other Expenses	0	0	0	0	0	168	0
68	99	881000	Rents	0	0	0	0	0	0	0
69										
70			MAINTENANCE							
71	99	885000	Supervision & Engineering	0	0	0	0	0	0	0
72	99	887000	Mains	0	0	0	0	0	0	0
73	99	889000	Measuring & Reg Sta Exp-General	0	0	0	0	0	0	0
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	0	0	0	0	0	0
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	0	0	0	0	0	0
76	99	892000	Services	0	0	0	0	0	0	0
77	99	893000	Meters & House Regulators	0	0	0	0	0	0	0
78	99	894000	Other Equipment	0	0	0	0	0	0	0
79			DISTRIBUTION O&M EXPENSES	0	0	0	0	0	168	0
80										
81	OR-DEPX		Depreciation Expense-Distribution	0	0	0	0	0	0	0
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	0	0	0	0	0	0
83										
84	OR-OTX		Taxes Other Than FIT-Distribution	0	0	0	0	0	0	0
85			TOTAL DISTRIBUTION NON-FIT TAXES	0	0	0	0	0	0	0
86										
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	0	0	0	0	0	0	0
88										
89			**TOTAL DISTRIBUTION EXPENSES**	**0**	**0**	**0**	**0**	**0**	**168**	**0**
90										
91			CUSTOMER ACCOUNTS EXPENSES:							
92	99	901000	Supervision	0	0	0	0	0	0	0
93	99	902000	Meter Reading Expenses	0	0	0	0	0	0	0
94	OR-90	903XXX	Customer Records & Collection Expenses	0	0	0	0	0	0	0
95	99	904000	Uncollectible Accounts	0	0	(43)	0	0	0	0
96	99	905000	Misc Customer Accounts	0	0	0	0	0	0	0
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**0**	**0**	**(43)**	**0**	**0**	**0**	**0**
98										
99			CUSTOMER SERVICE & INFO EXPENSES:							
100	OR-90	908XXX	Customer Assistance Expenses	0	0	0	0	0	0	0
101	99	909000	Advertising	0	0	0	0	0	0	0
102	99	910000	Misc Customer Service & Info Exp	0	0	0	0	0	0	0
103			**CUSTOMER SVC & INFO OPERATING EXP**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
104										
105			SALES EXPENSES:							
106	99	912000	Demonstrating & Selling Expenses	0	0	0	0	0	0	0
107	99	913000	Advertising	0	0	0	0	0	0	0
108	99	916000	Miscellaneous Sales Expenses	0	0	0	0	0	0	0
109			**SALES OPERATING EXPENSES**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
110										
111			ADMINISTRATIVE & GENERAL EXPENSES:							
112	99	920000	Salaries	0	0	0	(438)	0	0	(98)
113	99	921000	Office Supplies & Expenses	0	0	0	0	0	0	0
114	99	922000	A&G Expenses Transferred	0	0	0	0	0	0	0
115	99	923000	Outside Services Employed	0	0	0	0	0	0	0
116	99	924000	Property Insurance Premium	0	23	0	0	0	0	0
117	99	925XXX	Injuries and Damages	0	53	0	0	0	0	0
118	99	926XXX	Employee Pensions and Benefits	0	0	0	0	0	0	0
119	99	928000	Regulatory Commission Expenses	0	0	0	0	0	0	0
120	99	930000	Miscellaneous General Expenses	0	0	0	0	(40)	0	0

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.	Acct. No.	Description		Working Capital Adjustment	Forecast Insurance Adjustment	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment	Atmos Testing Restate Adjustment	Restated Salaries and Wages Adjustment
		Adjustment Number		2.09	2.10	3.00	3.01	3.02	3.03	3.04
		Workpaper Reference		G-FWC	G-IA	G-UE	G-IP	G-MD	G-AT	G-SW
121	99 931000	Rents		0	0	0	0	0	0	0
122	99 935000	Maintenance of General Plant		0	0	0	0	0	0	0
123		ADMIN & GENERAL OPERATING EXP		0	76	0	(438)	(40)	0	(98)
124										
125	OR-DEPX	Depreciation Expense-General		0	0	0	0	0	0	0
126		TOTAL A&G DEPRCIATION EXP		0	0	0	0	0	0	0
127										
128	OR-AMTX	Amortization Expense-General Plant-303000		0	0	0	0	0	0	0
129	OR-AMTX	Amortization Expense-Misc IT Intangible Plant-3031XX		0	0	0	0	0	0	0
130	OR-AMTX	Amortization Expense-General Plant-390200, 396200		0	0	0	0	0	0	0
131		TOTAL A&G AMRT/NON-FIT TAXES		0	0	0	0	0	0	0
132										
133		TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	0	0	0	0	0	0
134										
135		**TOTAL ADMIN & GENERAL EXPENSES**		**0**	**76**	**0**	**(438)**	**(40)**	**0**	**(98)**
136										
137		OTHER DEFERRALS AND AMORTIZATIONS:								
138	99 407330	Senate Bill 408		0	0	0	0	0	0	0
139	99 407408	Senate Bill Unbilled Add-Ons Amortization		0	0	0	0	0	0	0
140	99 407431	Senate Bill 408 Amortization		0	0	0	0	0	0	0
141	99 407321	Reg Amort Roseburg/Medford Deferral		0	0	0	0	0	0	0
142	99 407421	Reg Credit Roseburg/Medford Deferral		0	0	0	0	0	0	0
143		TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	0	0	0	0	0	0
144										
145		**TOTAL EXPENSES BEFORE FIT**		**0**	**76**	**(43)**	**(438)**	**(40)**	**168**	**(98)**
146										
147		**NET OPERATING INCOME (LOSS) BEFORE FIT**		**0**	**(76)**	**43**	**438**	**40**	**(168)**	**98**
148										
151		FEDERAL INCOME TAX--Normal Accrual	35.00%	0	(25)	14	142	13	(54)	32
152		DEBT INTEREST	2.780%	(71)	0	0	0	0	0	1
153		DEFERRED INCOME TAX		0	0	0	0	0	0	0
154		STATE INCOME TAXES	7.60%	0	(6)	3	33	3	(13)	7
155		GAS NET OPERATING INCOME (LOSS)		71	(46)	26	263	24	(101)	58
156										
157		RATE BASE								
158		PLANT IN SERVICE								
159		INTANGIBLE PLANT:								
160	99 303000	Misc Intangible Plant (303000)		0	0	0	0	0	0	0
161	99 3031XX	Misc Intangible IT Plant (3031XX)		0	0	0	0	0	0	0
		Misc Intangible Plant Proforma		0	0	0	0	0	0	0
162		TOTAL INTANGIBLE PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
163										
164		UNDERGROUND STORAGE PLANT:								
165	99 350100	Land in Fee		0	0	0	0	0	0	0
166	99 351100	S & I - Wells		0	0	0	0	0	0	0
167	99 351200	S & I - Compress Station		0	0	0	0	0	0	0
168	99 351300	S & I - Meas/Regulating Station		0	0	0	0	0	0	0
169	99 351400	S & I - Office		0	0	0	0	0	0	0
170	99 352000	Wells		0	0	0	0	0	0	0
171	99 352100	Wells - Leases		0	0	0	0	0	0	0
172	99 353000	Lines		0	0	0	0	0	0	0
173	99 354000	Compressor Stn Equipment		0	0	0	0	0	0	0
174	99 355000	Meas & Regulating Equipment		0	0	0	0	0	0	0
175	99 356000	Purification Equipment		0	0	0	0	0	0	0
176	99 357000	Other Equipment		0	0	0	0	0	0	0
		Underground Storage Plant Proforma		0	0	0	0	0	0	0
177		TOTAL UNDERGROUND STORAGE PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
178										
179		PRODUCTION PLANT:								
180	99 304000	Land & Land Rights		0	0	0	0	0	0	0
181	99 311XXX	LPG Equipment		0	0	0	0	0	0	0
		Production Plant Proforma		0	0	0	0	0	0	0
182		TOTAL PRODUCTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
183										
184		DISTRIBUTION PLANT:								
185	99 374200	Land & Land Rights		0	0	0	0	0	0	0
186	99 374400	Land Easements		0	0	0	0	0	0	0
187	99 375000	Structures & Improvements		0	0	0	0	0	0	0
188	99 376000	Mains		0	0	0	0	0	0	0
189	99 378000	Measuring & Reg Station Equip-General		0	0	0	0	0	0	0
190	99 379000	Measuring & Reg Station Equip-City Gate		0	0	0	0	0	0	0
191	99 380000	Services		0	0	0	0	0	0	0
192	99 381000	Meters		0	0	0	0	0	0	0
193	99 385000	Industrial Measuring & Reg Sta Equip		0	0	0	0	0	0	0
194	99 387000	Other Equipment		0	0	0	0	0	0	0
		Distribution Plant Proforma		0	0	0	0	0	0	(60)
195		TOTAL DISTRIBUTION PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**(60)**
196										
197		GAS GENERAL PLANT: (From C-GPL)								
198	389XXX	Land & Land Rights		0	0	0	0	0	0	0
199	390XXX	Structures & Improvements		0	0	0	0	0	0	0
200	391XXX	Office Furniture & Equipment		0	0	0	0	0	0	0
201	392XXX	Transportation Equipment		0	0	0	0	0	0	0
202	393000	Stores Equipment		0	0	0	0	0	0	0
203	394000	Tools, Shop & Garage Equipment		0	0	0	0	0	0	0
204	395000	Laboratory Equipment		0	0	0	0	0	0	0
205	396XXX	Power Operated Equipment		0	0	0	0	0	0	0
206	397XXX	Communications Equipment		0	0	0	0	0	0	0
207	398000	Miscellaneous Equipment		0	0	0	0	0	0	0
		General Plant Proforma		0	0	0	0	0	0	0
208		TOTAL GAS GENERAL PLANT		**0**	**0**	**0**	**0**	**0**	**0**	**0**
209										
210		**GROSS PLANT IN SERVICE**		**0**	**0**	**0**	**0**	**0**	**0**	**(60)**
211										
212		ACCUMULATED DEPRECIATION								
213	R-ADEP	Underground Storage		0	0	0	0	0	0	0
214	R-ADEP	Distribution Plant		0	0	0	0	0	0	0
215	R-ADEP	General Plant		0	0	0	0	0	0	0
216		TOTAL ACCUMULATED DEPRECIATION		0	0	0	0	0	0	0
217										
218		ACCUMULATED AMORTIZATION								
219	R-AAMT	General Plant - 303000		0	0	0	0	0	0	0
220	R-AAMT	Misc IT Intangible IT Plant - 3031XX		0	0	0	0	0	0	0
221	R-AAMT	General Plant - 390200, 396200		0	0	0	0	0	0	0
222		TOTAL ACCUMULATED AMORTIZATION		0	0	0	0	0	0	0
223										
224		TOTAL ACCUMULATED DEPR/AMORT		0	0	0	0	0	0	0
225										
226		NET GAS UTILITY PLANT before DFIT		0	0	0	0	0	0	(60)
227										
228		ACCUMULATED DFIT								
229	99 282900	ADFIT - Gas Plant in Service		0	0	0	0	0	0	0
230	282900	ADFIT - Common Plant (282900 from C-DTX)		0	0	0	0	0	0	0
231	283750	ADFIT - Common Plant (283750 from C-DTX)		0	0	0	0	0	0	0
232	99 283850	ADFIT - Bond Redemptions		0	0	0	0	0	0	0
233		ADFIT - Prepaid Pension		0	0	0	0	0	0	0
234		**TOTAL ACCUMULATED DFIT**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
235										
236		**NET GAS UTILITY PLANT**		**0**	**0**	**0**	**0**	**0**	**0**	**(60)**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description		Working Capital Adjustment	Forecast Insurance Adjustment	Uncollectible Expense Adjustment	Incentive Pay Adjustment	Memberships and Dues Adjustment	Atmos Testing Restate Adjustment	Restated Salaries and Wages Adjustment
			Adjustment Number		2.09	2.10	3.00	3.01	3.02	3.03	3.04
			Workpaper Reference		G-FWC	G-IA	G-UE	G-IP	G-MD	G-AT	G-SW
237											
238			GAS INVENTORY								
239	99	117100	Gas Stored - Recoverable Base Gas		0	0	0	0	0	0	0
240	99	164100	Gas Inventory - Jackson Prairie		0	0	0	0	0	0	0
241	99	164105	Gas Inventory - Jackson Prairie Expansion		0	0	0	0	0	0	0
242	99	164110	Gas Inventory - Mist		0	0	0	0	0	0	0
243			**TOTAL GAS INVENTORY**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
244											
245			OTHER REGULATORY ASSETS								
246			Prepaid Pension		0	0	0	0	0	0	0
247			Working Capital		6,355	0	0	0	0	0	0
248			**TOTAL OTHER REGULATORY ASSETS**		**6,355**	**0**	**0**	**0**	**0**	**0**	**0**
249											
250			**NET RATE BASE**		**6,355**	**0**	**0**	**0**	**0**	**0**	**(60)**
251											
252			**RATE OF RETURN**								
253											
254			**REVENUE REQUIREMENT**		**733**	**78**	**-44**	**-451**	**-41**	**173**	**-108**
255											
256			Pro Forma Rate of Return	7.83%							
257			Revenue Conversion Factor	0.58293							
258											
259			NOI Requirement		**427**	**46**	**-26**	**-263**	**-24**	**101**	**-63**
260			Revenue Requirement		**733**	**78**	**-44**	**-451**	**-41**	**173**	**-108**
261											
262			TAX CALCULATION:								
263			Net Operating Income		-	(76)	43	438	40	(168)	98
264			Other Deductions								
265			Interest		(177)	-	-	-	-	-	2
266			Net Schedule M Adjustments		-	-	-	-	-	-	-
267			Income Before Tax		(177)	(76)	43	438	40	(168)	100
268											
269			State Income Taxes		(13)	(6)	3	33	3	(13)	8
270			Taxable Income		(163)	(70)	40	405	37	(155)	92
271											
272			Federal Tax		(57)	(25)	14	142	13	(54)	32
273			Net Operating Income		(106)	(46)	26	263	24	(101)	60
270											
271			FOR INFORMATION ONLY:								
272			SIT Debt Interest		13	0	0	0	0	0	0
273			FIT Debt Interest		57	0	0	0	0	0	-1
274					71	0	0	0	0	0	-1

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description	State Income Tax Adjustment	Total Adjustments
			Adjustment Number	**3.05**	
			Workpaper Reference	**G-SIT**	
	REVENUES				
1			SALES OF GAS:		
2	99	480000	Residential	0	**455**
3	99	481200	Commercial	0	**(871)**
4	99	481300	Industrial-Firm	0	**(332)**
5	99	481400	Interruptible	0	**728**
6	99	484000	Interdepartmental Sales	0	**(14)**
7	99	499000	Unbilled Revenue	0	**1,195**
8			SALES TO ULTIMATE CUSTOMERS	0	**1,161**
9					
10			TRANSPORTATION REVENUES		
11	99	489300	Transportation - Commercial/Industrial	0	**35**
12			TRANSPORTATION REVENUES	0	**35**
13					
14			OTHER OPERATING REVENUES:		
15	99	483XXX	Sales For Resale	0	**(67,211)**
16	99	488000	Miscellaneous Service Revenues	0	**0**
17	99	493000	Other Gas Revenue - Gas Property Rent	0	**0**
18	99	495XXX	Other Gas Revenues	0	**(36)**
19			OTHER OPERATING REVENUES	0	**(67,247)**
20					
21	**TOTAL GAS REVENUES**			**0**	**(66,051)**
22					
23	**EXPENSES**				
24			PRODUCTION EXPENSES:		
25					
26			GAS PURCHASES		
27	OR-80	804XXX	Gas Purchases	0	**(64,355)**
28			TOTAL GAS PURCHASES	0	**(64,355)**
29					
30			OTHE GAS SUPPLY EXPENSE		
31	OR-80	805XXX	Other Gas Purchases	0	**389**
32	99	807000	Purchased Gas Expenses	0	**11**
33	OR-80	808XXX	Natural Gas Storage Transactions	0	**(576)**
34	99	811000	Gas Used for Products Extraction	0	**485**
35	99	813000	Other Gas Expenses	0	**23**
36	99	813010	Gas Technology Institute (GTI) Expenses	0	**1**
37			TOTAL OTHER GAS SUPPLY EXPENSE	0	**333**
38					
39			**TOTAL PRODUCTION EXPENSES**	**0**	**(64,022)**
40					
41			UNDERGROUND STORAGE EXPENSES:		
42	**99**	814000	Supervision & Engineering	0	**0**
43	**99**	824000	Other Expenses	0	**3**
44	**99**	837000	Other Equipment	0	**2**
45			TOTAL UG STORAGE OPER EXP	0	**5**
46					
47	R-DEPX		Depreciation Expense-Underground Storage	0	**(3)**
48			TOTAL UG STORAGE DEPRCIATION EXP	0	**(3)**
49					
50	OR-OTX		Taxes Other Than FIT-Underground Storage	0	**0**
51			TOTAL UG STORAGE NON-FIT TAXES	0	**0**
52					
53			TOTAL UG STORAGE DEPR/AMRT/NON-FIT TAXES	0	**(3)**
54					
55			**TOTAL UNDERGROUND STORAGE EXPENSES**	**0**	**2**
56					
57			DISTRIBUTION EXPENSES:		
58			OPERATION		
59	99	870000	Supervision & Engineering	0	**29**
60	99	871000	Distribution Load Dispatching	0	**0**
61	99	874000	Mains & Services Expenses	0	**57**
62	99	875000	Measuring & Reg Sta Exp-General	0	**12**
63	99	876000	Measuring & Reg Sta Exp-Industrial	0	**0**
64	99	877000	Measuring & Reg Sta Exp-City Gate	0	**0**
65	99	878000	Meter & House Regulator Expenses	0	**7**
66	99	879000	Customer Installation Expenses	0	**52**
67	99	880000	Other Expenses	0	**217**
68	99	881000	Rents	0	**1**
69					
70			MAINTENANCE		
71	99	885000	Supervision & Engineering	0	**2**
72	99	887000	Mains	0	**57**
73	99	889000	Measuring & Reg Sta Exp-General	0	**6**
74	99	890000	Measuring & Reg Sta Exp-Industrial	0	**1**
75	99	891000	Measuring & Reg Sta Exp-City Gate	0	**0**
76	99	892000	Services	0	**21**
77	99	893000	Meters & House Regulators	0	**21**
78	99	894000	Other Equipment	0	**8**
79			DISTRIBUTION O&M EXPENSES	0	**491**
80					
81	OR-DEPX		Depreciation Expense-Distribution	0	**1,749**
82			TOTAL DISTRIBUTION DEPRCIATION EXP	0	**1,749**
83					
84	OR-OTX		Taxes Other Than FIT-Distribution	0	**(751)**
85			TOTAL DISTRIBUTION NON-FIT TAXES	0	**(751)**
86					
87			TOTAL DISTR DEPR/AMRT/NON-FIT TAXES	0	**998**
88					
89			**TOTAL DISTRIBUTION EXPENSES**	**0**	**1,489**
90					
91			CUSTOMER ACCOUNTS EXPENSES:		
92	99	901000	Supervision	0	**0**
93	99	902000	Meter Reading Expenses	0	**12**
94	OR-90	903XXX	Customer Records & Collection Expenses	0	**90**
95	99	904000	Uncollectible Accounts	0	**(8)**
96	99	905000	Misc Customer Accounts	0	**2**
97			**CUSTOMER ACCOUNTS OPERATING EXP**	**0**	**96**
98					
99			CUSTOMER SERVICE & INFO EXPENSES:		
100	OR-90	908XXX	Customer Assistance Expenses	0	**(1,843)**
101	99	909000	Advertising	0	**9**
102	99	910000	Misc Customer Service & Info Exp	0	**2**
103			**CUSTOMER SVC & INFO OPERATING EXP**	**0**	**(1,832)**
104					
105			SALES EXPENSES:		
106	99	912000	Demonstrating & Selling Expenses	0	**0**
107	99	913000	Advertising	0	**0**
108	99	916000	Miscellaneous Sales Expenses	0	**0**
109			**SALES OPERATING EXPENSES**	**0**	**0**
110					
111			ADMINISTRATIVE & GENERAL EXPENSES:		
112	99	920000	Salaries	0	**(141)**
113	99	921000	Office Supplies & Expenses	0	**32**
114	99	922000	A&G Expenses Transferred	0	**0**
115	99	923000	Outside Services Employed	0	**86**
116	99	924000	Property Insurance Premium	0	**27**
117	99	925XXX	Injuries and Damages	0	**37**
118	99	926XXX	Employee Pensions and Benefits	0	**5**
119	99	928000	Regulatory Commission Expenses	0	**42**
120	99	930000	Miscellaneous General Expenses	0	**(13)**

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.	Acct.	No.	Description		State Income Tax Adjustment	Total Adjustments
			Adjustment Number		3.05	
			Workpaper Reference		G-SIT	
121	99	931000	Rents		0	6
122	99	935000	Maintenance of General Plant		0	47
123			ADMIN & GENERAL OPERATING EXP		0	128
124						
125	OR-DEPX		Depreciation Expense-General		0	255
126			TOTAL A&G DEPRCIATION EXP		0	255
127						
128	OR-AMTX		Amortization Expense-General Plant-303000		0	493
129	OR-AMTX		Amortization Expense-Misc IT Intangible Plant-3031XX		0	724
130	OR-AMTX		Amortization Expense-General Plant-390200, 396200		0	0
131			TOTAL A&G AMRT/NON-FIT TAXES		0	1,217
132						
133			TOTAL A&G DEPR/AMRT/NON-FIT TAXES		0	1,472
134						
135			**TOTAL ADMIN & GENERAL EXPENSES**		0	1,600
136						
137			OTHER DEFERRALS AND AMORTIZATIONS:			
138	99	407330	Senate Bill 408		0	(2)
139	99	407408	Senate Bill Unbilled Add-Ons Amortization		0	(156)
140	99	407431	Senate Bill 408 Amortization		0	844
141	99	407321	Reg Amort Roseburg/Medford Deferral		0	(200)
142	99	407421	Reg Credit Roseburg/Medford Deferral		0	323
143			TOTAL OTHER DEFERRALS AND AMORTIZATIONS:		0	809
144						
145	**TOTAL EXPENSES BEFORE FIT**				0	(61,858)
146						
147			**NET OPERATING INCOME (LOSS) BEFORE FIT**		0	(4,193)
148						
151			FEDERAL INCOME TAX--Normal Accrual	35.00%	1	(1,355)
152			DEBT INTEREST	2.780%	0	(288)
153			DEFERRED INCOME TAX		0	0
154			STATE INCOME TAXES	7.60%	(4)	(323)
155			GAS NET OPERATING INCOME (LOSS)		3	(2,227)
156						
157			RATE BASE			
158			PLANT IN SERVICE			
159			INTANGIBLE PLANT:			
160	99	303000	Misc Intangible Plant (303000)		0	0
161	99	3031XX	Misc Intangible IT Plant (3031XX)		0	0
			Misc Intangible Plant Proforma		0	8,898
162			TOTAL INTANGIBLE PLANT		0	8,898
163						
164			UNDERGROUND STORAGE PLANT:			
165	99	350100	Land in Fee		0	0
166	99	351100	S & I - Wells		0	0
167	99	351200	S & I - Compress Station		0	0
168	99	351300	S & I - Meas/Regulating Station		0	0
169	99	351400	S & I - Office		0	0
170	99	352000	Wells		0	0
171	99	352100	Wells - Leases		0	0
172	99	353000	Lines		0	0
173	99	354000	Compressor Stn Equipment		0	0
174	99	355000	Meas & Regulating Equipment		0	0
175	99	356000	Purification Equipment		0	0
176	99	357000	Other Equipment		0	0
			Underground Storage Plant Proforma		0	247
177			TOTAL UNDERGROUND STORAGE PLANT		0	247
178						
179			PRODUCTION PLANT:			
180	99	304000	Land & Land Rights		0	0
181	99	311XXX	LPG Equipment		0	0
			Production Plant Proforma		0	0
182			TOTAL PRODUCTION PLANT		0	0
183						
184			DISTRIBUTION PLANT:			
185	99	374200	Land & Land Rights		0	0
186	99	374400	Land Easements		0	0
187	99	375000	Structures & Improvements		0	0
188	99	376000	Mains		0	0
189	99	378000	Measuring & Reg Station Equip-General		0	0
190	99	379000	Measuring & Reg Station Equip-City Gate		0	0
191	99	380000	Services		0	0
192	99	381000	Meters		0	0
193	99	385000	Industrial Measuring & Reg Sta Equip		0	0
194	99	387000	Other Equipment		0	0
			Distribution Plant Proforma		0	28,388
195			TOTAL DISTRIBUTION PLANT		0	28,388
196						
197			GAS GENERAL PLANT: (From C-GPL)			
198		389XXX	Land & Land Rights		0	0
199		390XXX	Structures & Improvements		0	0
200		391XXX	Office Furniture & Equipment		0	0
201		392XXX	Transportation Equipment		0	0
202		393000	Stores Equipment		0	0
203		394000	Tools, Shop & Garage Equipment		0	0
204		395000	Laboratory Equipment		0	0
205		396XXX	Power Operated Equipment		0	0
206		397XXX	Communications Equipment		0	0
207		398000	Miscellaneous Equipment		0	0
			General Plant Proforma		0	4,708
208			TOTAL GAS GENERAL PLANT		0	4,708
209						
210			**GROSS PLANT IN SERVICE**		0	42,241
211						
212			ACCUMULATED DEPRECIATION			
213	R-ADEP		Underground Storage		0	(224)
214	R-ADEP		Distribution Plant		0	(7,894)
215	R-ADEP		General Plant		0	(2,160)
216			TOTAL ACCUMULATED DEPRECIATION		0	(10,278)
217						
218			ACCUMULATED AMORTIZATION			
219	R-AAMT		General Plant - 303000		0	0
220	R-AAMT		Misc IT Intangible IT Plant - 3031XX		0	(1,698)
221	R-AAMT		General Plant - 390200, 396200		0	0
222			TOTAL ACCUMULATED AMORTIZATION		0	(1,698)
223						
224			TOTAL ACCUMULATED DEPR/AMORT		0	(11,976)
225						
226			NET GAS UTILITY PLANT before DFIT		0	30,265
227						
228			ACCUMULATED DFIT			
229	99	282900	ADFIT - Gas Plant in Service		0	(4,640)
230		282900	ADFIT - Common Plant (282900 from C-DTX)		0	(1,054)
231		283750	ADFIT - Common Plant (283750 from C-DTX)		0	0
232	99	283850	ADFIT - Bond Redemptions		0	0
233			ADFIT - Prepaid Pension		0	(2,000)
234			**TOTAL ACCUMULATED DFIT**		0	(7,694)
235						
236			**NET GAS UTILITY PLANT**		0	22,571

AVISTA UTILITIES
OREGON NATURAL GAS
TWELVE MONTHS ENDED DECEMBER 31, 2012
(000's OF DOLLARS)

Line No.		Acct. No.	Description		State Income Tax Adjustment	Total Adjustments
			Adjustment Number		**3.05**	
			Workpaper Reference		**G-SIT**	
237						
238			GAS INVENTORY			
239	99	117100	Gas Stored - Recoverable Base Gas		0	**0**
240	99	164100	Gas Inventory - Jackson Prairie		0	**0**
241	99	164105	Gas Inventory - Jackson Prairie Expansion		0	**0**
242	99	164110	Gas Inventory - Mist		0	**0**
243			**TOTAL GAS INVENTORY**		**0**	**0**
244						
245			OTHER REGULATORY ASSETS			
246			Prepaid Pension		0	**5,710**
247			Working Capital		0	**6,355**
248			**TOTAL OTHER REGULATORY ASSETS**		**0**	**12,065**
249						
250			**NET RATE BASE**		**0**	**34,636**
251						
252			**RATE OF RETURN**			
253						
254			**REVENUE REQUIREMENT**		**-5**	**8,472**
255						
256			Pro Forma Rate of Return	7.83%		
257			Revenue Conversion Factor	0.58293		
258						
259			NOI Requirement		**-3**	**4,939**
260			Revenue Requirement		**-5**	**8,472**
261						
262			TAX CALCULATION:			
263			Net Operating Income		-	**(4,193)**
264			Other Deductions			**-**
265			Interest		-	**(963)**
266			Net Schedule M Adjustments		-	-
267			Income Before Tax		-	**(5,156)**
268						**-**
269			State Income Taxes		-	**(392)**
270			Taxable Income		-	**(4,764)**
271						**-**
272			Federal Tax		-	**(1,667)**
273			Net Operating Income		-	**(3,097)**
270						
271			FOR INFORMATION ONLY:			
272			SIT Debt Interest		0	**73**
273			FIT Debt Interest		0	**311**
274					0	385

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

ELIZABETH M. ANDREWS
Exhibit No. 603

Revenue Requirement and Allocations

AVISTA®

ALLOCATION PROCESSES AND METHODOLOGIES

Oregon

July 15, 2013

Purpose of Presentation

UG-201 – Stipulation Resolving All Issues, Dated January 31, 2011

10. Other Issues

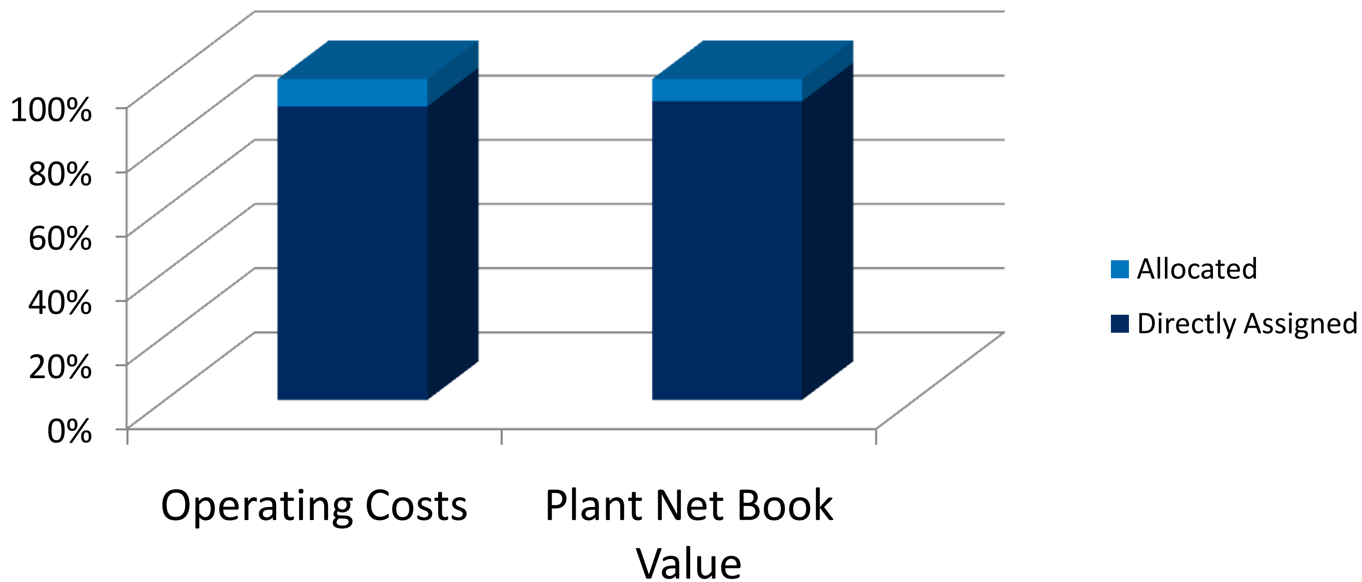
(c.) Allocation Methodology – The Company will meet with the Parties prior to the Company's next general rate case filing to discuss the Company's allocation processes and methodologies.

Introduction

- The Company directly assigns revenues and costs, when appropriate. Costs not specifically identifiable to a specific Service and Jurisdiction must be allocated using a reasonable method.
- The Company's methodology of using 4-factor allocation factors to allocate non-direct costs is consistently used in all 3 states.
- The Company updates the allocation factors each year, using actual direct costs. Updating factors with current costs and customers is appropriate so growth in each jurisdiction is factored into the allocation. By updating the factors, if any Service or Jurisdiction has disproportionate growth of customers or costs, the 4-factor will reflect the shift in costs.

Introduction (con't)

- Approximately 92% of Oregon's 2012 costs were directly assigned and 8% were allocated.
- Approximately 93% of Oregon's net plant at December 31, 2012 was directly assigned and 7% was allocated.



Agenda

I. Why are Costs Allocated?
II. How are Costs Allocated?
III. How are Allocation Factors Derived?
IV. How are Oregon's Costs Allocated?

I. Why are Costs Allocated?

Why are Costs Allocated?

The Company operates 3 operating divisions:

- Electric (provides service in WA and ID)
- Gas North (provides service in WA and ID)
- Gas South (provides service in OR)

Revenues, Costs and Rate Base not specifically identifiable to a specific Service and Jurisdiction must be allocated using a reasonable method.

For example, Avista's main headquarters in Spokane provides service to all services and jurisdictions, therefore the operating costs, depreciation expense and net book value of the building is allocated to all operating units using allocation factors.

Cost Assignment and Allocation

- Revenues, Operating Costs and Rate Base are DIRECTLY ASSIGNED to Service (electric/natural gas) and Jurisdiction (WA/ID/OR), whenever possible.
- For revenues, operating costs and rate base that are not directly assigned ("common"), the Company allocates based on the Service and Jurisdiction related to those common costs using the Service Codes and Jurisdiction Codes assigned to those common costs.
- The Company uses allocation factors derived from the directly assigned costs to allocate the “common” costs.

II. How are Costs Allocated?

Financial System Codes

Service Codes

- ED – Electric
- GD – Gas
- CD – Common
- ZZ – No Service

Jurisdiction Codes

- AA – Allocated All
- AN – Allocated North
- ID – Idaho
- MT – Montana
- OR – Oregon
- WA – Washington
- ZZ – No Jurisdiction

Possible Combinations of Service and Jurisdiction Codes

Service	CD	ED	GD	ZZ
Jurisdiction	AA, AN, ID, WA	AN, ID, MT, WA	AA, AN, ID, OR, WA	ZZ

Cost Assignment and Allocation – Where the Costs are Assigned

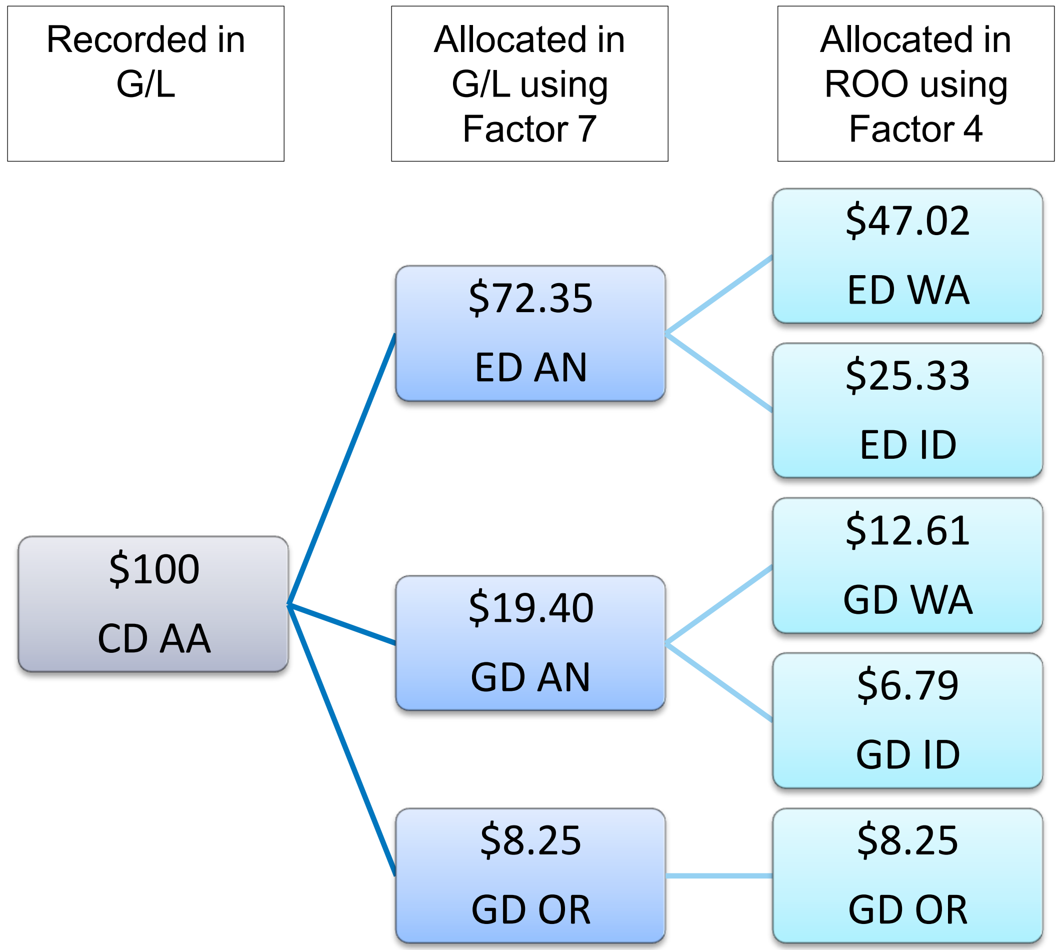
1	Service	CD				ED				GD					ZZ
2	Jurisdiction	**AA**	AN	ID	WA	AN	ID	MT	WA	**AA**	AN	ID	**OR**	WA	ZZ
3	Directly Assigned						ID	MT	WA			ID	**OR**	WA	
4	Allocated in GL	**AA**	AN	ID	WA					**AA**					
5	Allocation Factor	7	9	9	9					8					
6	**CD AA**					E1					G1		**G1**		
7	CD AN					E2					G2				
8	CD ID						E2					G2			
9	CD WA								E2					G2	
10	**GD AA**										G3		**G3**		
11	Allocated in ROO					AN					AN				
12						E1					G1				
13						E2					G2				
14											G3				

Service Codes
ED – Electric
GD – Gas
CD – Common
ZZ – No Service

Jurisdiction Codes
AA – Allocated All
AN – Allocated North
ID – Idaho
MT – Montana
OR – Oregon
WA – Washington
ZZ – No Jurisdiction

Note: Bolded/highlighted items represent assignments and allocations that impact Oregon.

How does $100 of Common costs get allocated?



III. How are Allocation Factors Derived?

Cost Assignment and Allocation – How the Factors are Computed

- As in the past, the Company computes 3 factors annually using the previous year's direct costs, including:
  - Factor 7 Allocate CD AA (Common costs for all services and jurisdictions)
  - Factor 8 Allocate GD AA (Common GAS costs for all 3 jurisdictions)
  - Factor 9 Allocate CD AN, ID, and WA (Common costs for both services for the North division, therefore, not used by Oregon)
- These factors are entered into the GL and the allocations of costs are recorded in the GL automatically

Allocation Factors 7, 8 and 9 (“4-Factor”)

- Based on equal weightings (i.e. 25% to each factor) of the following 4 factors:
  - Direct O&M and A&G costs (excluding labor)
  - Direct labor costs
  - Number of customers
  - Net direct plant

2013 Factor 7 (Used to Allocate CD AA Costs and Rate Base)

	Total	Electric	Gas North	Oregon
Direct Non-Labor				
O&M (Accts 500-894)	$68,965,506	$60,243,237	$5,651,108	$3,071,161
A&G - ED & GD (Accts 901-935)	41,147,627	29,854,933	8,129,433	3,163,261
A&G - CD (Accts 901-935)	4,465,312	3,053,607	1,411,705	-
Total	$114,578,445	$93,151,777	$15,192,246	$6,234,422
Percentage	100.000%	81.300%	13.259%	5.441%
Direct Labor				
O&M (Accts 500-894)	$65,772,800	$51,029,386	$10,468,202	$4,275,212
A&G - ED & GD (Accts 901-935)	5,175,642	3,333,358	497,385	1,344,899
A&G - CD (Accts 901-935)	10,669,036	7,158,435	3,510,601	-
Total	$81,617,478	$61,521,179	$14,476,188	$5,620,111
Percentage	100.000%	75.377%	17.737%	6.886%
Year End Customers at 12/31/12				
Washington	387,837	237,724	150,113	
Idaho	200,844	124,738	76,106	
Oregon	96,651			96,651
Total	685,332	362,462	226,219	96,651
Percentage	100.000%	52.888%	33.009%	14.103%
Net Direct Plant (Ending Balance at 12/31/12)				
Amount	$2,540,576,273	$2,027,886,265	$345,513,055	$167,176,953
Percentage	100.000%	79.820%	13.600%	6.580%
Four Factor				
Total	400.000%	289.385%	77.605%	33.010%
Average	100.000%	72.346%	19.401%	8.253%

Examples of Common (CD AA) Costs:
- Customer Service Reps
- Main Office Building
- Office Supplies

The factor for 2013 was computed using actual 2012 costs

2013 Factor 8 (Used to Allocate GD AA Costs and Rate Base)

	Total	Electric	Gas North	Oregon
Direct Non-Labor				
O&M (Accts 500-894)	$8,210,713		$5,319,674	$2,891,039
A&G - ED & GD (Accts 901-935)	10,885,298		7,836,155	3,049,143
A&G - CD (Accts 901-935)	1,411,705		1,411,705	-
Total	$20,507,716	$0	$14,567,534	$5,940,182
Percentage	100.000%	0.000%	71.034%	28.966%
Direct Labor				
O&M (Accts 500-894)	$11,244,329		$7,983,762	$3,260,567
A&G - ED & GD (Accts 901-935)	1,531,702		413,533	1,118,169
A&G - CD (Accts 901-935)	3,510,601		3,510,601	-
Total	$16,286,632	$0	$11,907,896	$4,378,736
Percentage	100.000%	0.000%	73.115%	26.885%
Year End Customers at 12/31/12	322,870		226,219	96,651
Percentage	100.000%	0.000%	70.065%	29.935%
Net Direct Plant (Ending Balance at 12/31/12)				
Amount	$504,945,491		$338,644,009	$166,301,482
Percentage	100.000%	0.000%	67.065%	32.935%
Four Factor				
Total	400.000%	0.000%	281.279%	118.721%
Average	100.000%	0.000%	70.320%	29.680%

Examples of Common (GD AA) Costs:
- Gas Operations Costs

The factor for 2013 was computed using actual 2012 costs

Direct Costs are Used to Derive Allocation Factors

- FERC Accounts 500000 through 935000 are summarized by:
  - Service/Jurisdiction
  - O&M, A&G and Power Supply Costs (Non-labor power supply costs are excluded from costs to determine allocation factors, due to high variability.)
  - Labor vs Non-Labor

2012 Costs Used for 2013 Factors – Non-Labor

Line	Service	Jurisdiction	A&G	O&M	PS	Grand Total
1	CD	AA	53,508,815	-	-	53,508,815
2		AN	2,261,617	-	-	2,261,617
3		ID	706,885	-	-	706,885
4		WA	1,496,811	-	-	1,496,811
5	CD Total		57,974,128	-	-	57,974,128
6	ED	AN	3,572,724	40,021,277	474,020,292	517,614,293
7		ID	7,520,329	7,086,539	3,902,652	18,509,520
8		WA	18,761,880	13,135,421	9,571,021	41,468,323
9	ED Total		29,854,933	60,243,238	487,493,965	577,592,136
10	GD	AA	407,396	511,556	-	918,953
11		AN	(22,684)	1,452,051	209,439,250	210,868,617
12		ID	1,227,450	1,084,933	(1,143,018)	1,169,365
13		OR	3,049,144	2,891,039	119,517,387	125,457,569
14		WA	6,631,389	2,782,690	(4,165,892)	5,248,187
15	GD Total		11,292,695	8,722,270	323,647,726	343,662,691
16	Grand Total		99,121,755	68,965,507	811,141,692	979,228,954

The 2012 costs were obtained from the Projects subledger using Discoverer.

2012 Costs Used for 2013 Factors – Labor

Line	Service	Jurisdiction	A&G	O&M	PS	Grand Total
1	CD	AA	52,333,168	-	-	52,333,168
2		AN	2,655,275	-	-	2,655,275
3		ID	1,579,164	-	-	1,579,164
4		WA	6,434,597	-	-	6,434,597
5	CD Total		63,002,204	-	-	63,002,204
6	ED	AN	2,300,780	30,830,183	6,739,614	39,870,576
7		ID	257,760	4,701,873	-	4,959,634
8		WA	774,818	8,757,716	-	9,532,533
9	ED Total		3,333,358	44,289,772	6,739,614	54,362,743
10	GD	AA	310,582	3,499,085	-	3,809,667
11		AN	-	1,605,723	-	1,605,723
12		ID	78,802	2,101,313	-	2,180,115
13		OR	1,118,169	3,260,567	-	4,378,736
14		WA	334,731	4,276,726	-	4,611,457
15	GD Total		1,842,284	14,743,414	-	16,585,698
16	Grand Total		68,177,846	59,033,186	6,739,614	133,950,646

The 2012 costs were obtained from the Projects subledger using Discoverer.

Summary of Costs by Allocation Factor

Non-Labor Costs

	Factor 7
Total Non-Labor	979,228,954
Less: Power Supply Costs	(811,141,692)
Less: CD AA Costs	(53,508,815)
	114,578,448

	Factor 8
Total Non-Labor GD	343,662,691
Less: Power Supply Costs GD	(323,647,726)
Less: GD AA Costs	(918,953)
Add: Gas North Share of Common CD Costs	1,411,705
	20,507,717

Labor Costs

	Factor 7
Total Labor	133,950,646
Less: CD AA Costs	(52,333,168)
	81,617,478

	Factor 8
Total Labor GD	16,585,698
Less: GD AA Costs	(3,809,667)
Add: Gas North Share of Common CD Costs	3,510,601
	16,286,633

Note: For purposes of computing the factors, common costs related to WA/ID are treated as direct. This ensures that the allocation factors include similar costs for all services and jurisdictions.

Cost Assignment and Allocation – How the Costs are Allocated

- The 3 factors (7, 8 and 9) are entered into the GL and the allocations of costs are recorded in the GL automatically.
- For “O&M Costs” and “A&G Costs”:
  - FERC Accounts 901 through 917 (Customer Accounts and Customers Service Costs), the number of customers is used as the allocation factor.
  - FERC Accounts 920 through 935 (A&G), the 4-factor allocator is used as the allocation factor.
- For “Revenues”, “Other Costs” and “Rate Base” not directly assigned, the 4-factor is used as the allocation factor.

IV. How are Oregon's Costs Allocated?

Allocation of 2012 Costs for Oregon

Line	Service	Jurisdiction	System	Oregon	Oregon %
1	CD	AA	124,292,134	11,313,037	7.5%
2		AN	4,916,892	-	
3		ID	2,286,049	-	
4		WA	7,931,408	-	
5	CD Total		139,426,483	11,313,037	
6	ED	AN	557,484,869	-	
7		ID	23,469,154	-	
8		WA	51,000,856	-	
9	ED Total		631,954,879	-	
10	GD	AA	5,269,370	1,563,949	1.0%
11		AN	212,474,341	-	
12		ID	3,349,480	-	
13		OR	138,801,390	138,801,390	91.5%
14		WA	9,859,644	-	
15	GD Total		369,754,225	140,365,339	
16	Grand Total		1,141,135,587	151,678,376	100.0%

The 2012 costs were obtained from the Projects subledger using Discoverer.

Detail of CD AA Costs Allocated to Oregon

Line	Ferc Acct	System	OR	Factor
1	403000	10,729,656	885,519	8.253%
2	404000	7,892,553	651,372	8.253%
3	901000	1,092,096	154,018	14.103%
4	903000	12,025,517	1,695,959	14.103%
5	904000	4,024,468	567,571	14.103%
6	905000	433,612	61,152	14.103%
7	908000	93	13	14.103%
8	909000	128,877	18,176	14.103%
9	910000	333,026	46,967	14.103%
10	920000	47,068,011	3,884,523	8.253%
11	921000	5,444,074	449,299	8.253%
12	922000	2,047	169	8.253%
13	923000	15,896,727	1,311,957	8.253%
14	924000	1,527,074	126,029	8.253%
15	925100	3,648,345	301,098	8.253%
16	926100	1,022,155	84,358	8.253%
17	928000	1,268,341	104,676	8.253%
18	930100	1,756	145	8.253%
19	930200	3,236,584	267,115	8.253%
20	931000	1,143,326	94,359	8.253%
21	935000	7,373,827	608,562	8.253%
22		124,292,164	11,313,037	

The 2012 costs were obtained from the Projects subledger using Discoverer.

Net Plant at December 31, 2012 for Oregon using 2013 Allocation Factors

Line	Ferc Acct	Ferc Acct Desc	Ser.	Jur.	System	OR %	Oregon
1	101000	PLANT IN SERVICE OWNED	CD	AA	182,185,575	8.253%	15,035,776
2	101000	PLANT IN SERVICE OWNED	GD	AA	5,052,685	29.680%	1,499,637
3	101000	PLANT IN SERVICE OWNED	GD	OR	257,861,488	100.000%	257,861,488
4					445,099,748		274,396,900
5	108000	ACCUMULATED PROVISION DEPRECIATION	CD	AA	(24,556,570)	8.253%	(2,026,654)
6	111000	ACCUMULATED PROVISION AMORTIZATION	CD	AA	(19,746,594)	8.253%	(1,629,686)
7	108000	ACCUMULATED PROVISION DEPRECIATION	GD	AA	(1,317,830)	29.680%	(391,132)
8	111000	ACCUMULATED PROVISION AMORTIZATION	GD	AA	(785,154)	29.680%	(233,034)
9	108000	ACCUMULATED PROVISION DEPRECIATION	GD	OR	(91,461,333)	100.000%	(91,461,333)
10	111000	ACCUMULATED PROVISION AMORTIZATION	GD	OR	(98,671)	100.000%	(98,671)
11					(137,966,152)		(95,840,509)

The 2012 costs were obtained from the General Ledger using Discoverer.

Summary

- The Company obtained approval from all 3 state utility commissions (WA, ID and OR) to utilize the current allocation methodology.
- The Company updates the allocation factors each year, using actual direct costs.
- Oregon's total costs in 2012 were 91.5% directly assigned costs and 8.5% allocated costs.
- Oregon's net plant at December 31, 2012 was 93.1% directly assigned and 6.9% allocated.
- Updating factors with current costs, customers and net plant is appropriate so growth in each jurisdiction is factored into the allocation of common costs.

Questions?

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF DAVE B. DEFELICE
REPRESENTING AVISTA CORPORATION

Capital Projects

I. INTRODUCTION

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

A. My name is Dave DeFelice. I am employed by Avista Corporation as a Senior Business Analyst. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your education background and professional experience.

A. I graduated from Eastern Washington University in June of 1983 with a Bachelor of Arts Degree in Business Administration majoring in Accounting. I have served in various positions within the Company, including Analyst positions in the Finance Department (Rates Section and Plant Accounting) and in the Marketing/Operations Departments, as well. In 1999, I accepted the Senior Business Analyst position that focuses on economic analysis of various project proposals as well as evaluations and recommendations pertaining to business policies and practices.

Q. As a Senior Business Analyst, what are your responsibilities?

A. As a Senior Business Analyst, I am involved in financial analysis of numerous projects within various departments such as Engineering, Operations, Marketing/Sales and Finance.

Q. What is the scope of your testimony?

A. My testimony in this proceeding will cover the Company's proposed regulatory treatment of capital investments in utility plant through June 30, 2014. In addition, for informational purposes only, I provide information on capital investment though 2015 as an indication of the ongoing capital investments by the Company. The 2015 capital additions have not been included in the Company's request. I also discuss the impact of the recently authorized depreciation study rates, approved by the Oregon Commission in Docket No. UM 1626, by Order No. 13-168.

II. CAPITAL INVESTMENT RECOVERY

Q. What does the Company's request for rate relief include regarding new investment in utility plant to serve customers?

A. In this filing, we are proposing to include in retail rates, the costs associated with utility plant that will be used to provide natural gas service to our customers up through June 30, 2014 of the 2014 forecasted test period. Including the costs associated with this investment in retail rates, provides a proper "matching" of revenues from customers, with the costs associated with providing service to customers (including the cost of utility plant to serve customers).

Q. How was rate base for the forecasted test year developed for this filing?

A. Avista started with rate base using historical accounting information, which for this case is the average of monthly average (AMA) balances for the twelve months ended December 31, 2012. Adjustments were made to plant in service, accumulated depreciation and deferred federal income taxes (DFIT) at December 31, 2012, to restate net plant to the end of period (EOP) balances June 30, 2014. In addition, adjustments were made to reflect 2013 and 2014[1] plant additions and associated accumulated depreciation and DFIT through June 30, 2014 on an EOP basis, such that the proposed rate base reflects the net plant in service that will be used to serve customers during the 2014 forecasted test year.

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[1] The Company has included EOP June 30, 2014 for all plant including the Customer Information System (CIS) project although it has an estimated in-service date of July 2014, at which time 90% of the project is estimated to be complete and will go-live. The remaining 10% is related to post production support expected for 90 days following the go-live date.

Company witness Ms. Andrews incorporates these adjustments in her revenue requirements computation and provides the adjustment detail in her workpapers.

Q. Why did the Company forecast additions through June 30, 2014 on an EOP basis, instead of forecasting all additions in 2014 and using a December 31, 2014 AMA basis?

A. The June 30, 2014 EOP rate base reflects the net plant in service that will be used to serve customers during the 2014 forecasted test year, and is consistent with the use of 2014 forecasted revenues and expenses. Including the costs associated with this investment in retail rates provides a proper "matching" of revenues from customers with the costs associated with providing service to customers, including the cost of utility plant used to serve customers.

The "test year" should reflect costs and revenues that will fairly represent the period when prices from the docket will be in effect following a general rate case proceeding. For capital expenditures, the test year rate base reflects capital additions through June 30, 2014. Most of these capital projects, with the exception of the Customer Information System, are blanket projects and are transferred to plant in service monthly. Therefore, using an end of period balance midway through the year, best reflects the conditions during the time new rates will be in effect, as well as the end of the statutory period for this docket. It also ensures that when new base rates go into effect, all plant will be used and useful.

Q. ORS 757.355 states "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation of real or personal property not presently used for providing utility service to the customer." Are the capital additions included in this case consistent with ORS 757.355?

A. Yes. Ballot Measure 9, codified as ORS 757.355, applies only to new facilities and does not apply to capital improvements to existing facilities that are currently used and useful, like the capital improvements included in this docket. See UM989, Order No. 02-227 ("ORS 757.355 does not apply to routine construction work in progress (CWIP) attached to an operating plant. Ballot Measure 9, codified as ORS 757.355, was intended to apply to CWIP that reflects preconstruction commercial operating plants, not smaller projects attached to an operating plant").

Q. Are the capital projects that will transfer to plant by June 30, 2014 that the Company pro formed into this case routine construction work that is attached to existing operating plant?

A. Yes, all of the projects that will transfer to plant by June 30, 2014 that were pro formed in this case (as well as the remaining 2014 plant additions the Company did not pro form into this case) are work on existing operating plant. Avista currently has natural gas infrastructure that is being used to provide service to customers. These capital additions are either expansions or upgrades to this existing plant. None of this work represents costs on preconstruction operating plant.

Q. If all 2014 plant additions are either expansions or upgrades to existing plant, why did the Company not include the second half of 2014 capital additions within its request?

A. The Company believes it could have included all 2014 capital additions within its request on an AMA basis, consistent with the Company's inclusion of all revenue and customers for the 2014 forecasted test period. However, in order to minimize the issues in this proceeding related to the question of "used and useful" during the forecasted test period by the parties, the

Company chose to include only plant through June 30, 2014, but reserves the right to pro form all forecasted test period capital additions in future rate proceedings.

Q. What is the net impact of the capital pro forma adjustments included in this filing?

A. Rate base currently authorized (UG-201) is $140,738,664 which represents plant through June 2011[2], while the forecasted level of rate base through June 30, 2014 in this filing is $162,301,000.

Q. What are Avista's capital expenditures that will transfer to plant in service in 2013 and the six months ended June 30, 2014 that have been included in this case?

A. As shown in Table 1 below, Avista forecasts system-wide general plant capital expenditures of $62.969 million in 2013 and $88.372 million through June 30, 2014 (Oregon's share totals $5.198 million and $7.294 million for 2013 and through June 30, 2014, respectively.)

[2] The total amount of $140,738,664 in rate base consists of $137,199,000 included in the final order 11-080 effective March 15, 2011 and an additional increase in rate base deferred and implemented June 1, 2012 of $3,539,664 associated with two additional large capital projects completed in Q.4 of 2011.

Table 1
General Plant Capital Expenditures in 000's

Project	2013 System	2013 Oregon Allocated	June 30, 2014 System	June 30, 2014 Oregon Allocated
Security Initiative	$ 848	$ 70	$ 269	$ 22
Information Technology Refresh Projects-Software	13,053	1,077	6,531	539
Information Technology Expansion Projects-Software	6,461	533	2,066	170
Security Systems	1,385	114	746	62
Next Gen Radio	7,997	660	1,371	113
Microwave Replacement with Fiber	1,500	124	758	63
Customer Information System	-	-	68,700	5,670
Transportation Equipment	10,728	885	3,013	249
Structures and Improvements	2,950	243	1,588	131
Tools Lab & Shop Equipment	880	73	848	70
COF HVAC Improvement	7,383	609	-	-
Long Term Campus Re-Structuring Plan	5,540	457	-	-
CNG Fleet Conversion	1,628	134	108	9
Small Technology Projects	1,880	155	1,635	135
Small General Projects	736	64	739	61
TOTAL	$ 62,969	$ 5,198	$ 88,372	$ 7,294

As shown in Table 2 below, Avista forecasts Oregon natural gas distribution capital expenditures of $19.237 million in 2013 and $6.452 million through June 30, 2014.

Table 2
Oregon Gas Distribution Capital Expenditures in 000's

Project	2013	June 30, 2014
Oregon - Gas Revenue Projects	$ 3,043	$ 1,004
Gas Reinforce - Minor Blanket	131	80
Replace Deteriorating Gas System	736	216
Regulator Reliable -Blanket	239	64
Gas Replace - Street & Highway	1,940	698
Cathodic Protection - Minor Blanket	121	54
Gas Distribution Non-Revenue Projects	2,943	903
Overbuilt Pipe Replacement Projects	878	388
Isolated Steel	881	531
Aldyl-A Pipe Replaement	4,100	2,026
East Medford Reinforcement	687	0
Klamath Falls Lateral [3]	2,650	0
Other small gas Projects	888	488
TOTAL	$ 19,237	$ 6,452

[3] Klamath Falls Lateral had a purchase price of $2,277,014. The revenue requirement associated with this purchase is $450,039. The difference between the purchase price of $2,277,014 and the amount listed above of $ 2,650,000 relates to overheads and additional time and expenses coded to the project.

Capital Projects

Q. What is driving the significant investment in new utility plant in Oregon?

A. The Company is being required to add significant new distribution facilities due to reliability requirements and capacity upgrades. Other issues driving the need for capital investment include replacing a legacy customer information system, aging infrastructure, physical degradation, and municipal compliance issues (i.e., street/highway relocations), etc. Detailed explanations of the two major projects (Aldyl-A Pipe Replacement Program and Customer Information System) that are included in this case are summarized by Company witness La Bolle in his testimony and exhibits.

III. DESCRIPTION OF CAPITAL PROJECTS

Q. For the capital projects that will transfer to plant in service in 2013 and the six months ended June 30, 2014 that were pro formed in this filing, please provide a description of the projects.

A. Tables 1 and 2 above detail the capital projects included in this filing that will be transferred to plant in service in 2013 and as of the six months ended June 30, 2014. Please note that all the items labeled 2014 below are for capital projects that will transfer to plant in service during the six months ended June 30, 2014. A short description of these projects and their costs allocated to Oregon follows:

Technology (Oregon):

ER 5002 Security Initiative – 2013: $70,000; 2014: $22,000
Various security measures including cameras and access controls for the office and branch facilities.

ER 5005 Information Technology Refresh Projects - 2013: $1,077,000; 2014: $539,000
A program to replace obsolete technology according to Avista's refresh cycles that are generally driven by hardware/software manufacturer and industry trends to maintain business operations.

ER 5006 Information Technology Expansion Projects – 2013: $533,000; 2014: $170,000

A program to deliver technology associated with expansion of existing solutions.

ER 5014 Security Systems - 2013: $114,000; 2014: $170,000

This program is to maintain and improve all security aspects to protect people, assets, information & operations through projects, activities and polices. It will also manage the number of security incidents at a level that aligns with our corporate risk expectations. Additionally it will increase the culture of security through education and training.

ER 5106 Next Gen Radio– 2013: $660,000; 2014: $113,000

This project is refreshing Avista's 20 year old Land Mobile Radio (LMR) system that is used for critical crew communications during outage restoration and daily operations of maintaining the electric and natural gas distribution and transmission systems. The driver for this project is a mandate from the Federal Communications Commission (FCC). The FCC has, through Rule Making and Order No. RM-9332 release date December 23, 2004, ruled that all licensees in the Industrial/Business Radio Pool operating in the 150-174 MHz and 421-512 MHz bands migrate to spectrum efficient narrowband technology. Failure to act would result in violation of the FCC Narrow banding mandate (Rule 9332), and as quoted from the order, "Operation in violation of the Commission's rules may subject licensees to appropriate enforcement action, including admonishments, license revocation, and/or monetary forfeitures of up to $16,000 for each such violation or each day of a continuing violation and up to $112,500 for any single act or failure to act."

ER 5121 Microwave Replacement with Fiber-2013: $124,000; 2014: $63,000

The project is designed to replace the aging and no longer supported microwave equipment with a supported technology. These systems support the communication for protection and relaying of the electrical transmission systems that allow the reliable delivery of electricity throughout our service territory.

ER 5138 Customer Information System (Project Compass) – 2014: $5,670,000

The Customer Information System (CIS) will be implemented in two waves. The first wave includes the Maximo application in the Company's areas of Generation, Production, and Substation Support. This wave has an estimated go-live date or transfer to plant date of September 2013 and a system cost of approximately $10,300,000. This first wave is not included in this filing, as it all relates to electric operations. The second wave, includes Maximo application in the Company's areas of Transmission, Distribution, and Gas Operations, as well as the Customer Care and Billing application. These applications have a transfer to plant date of July 2014 and a system cost of approximately $68,700,000. This large technology project is described in detail in the testimony of Mr. La Bolle.

Other Small Technology Projects – 2013: $155,000; 2014: $135,000

These projects include various small technology projects including, SCADA upgrades, enterprise continuity software, moducom replacement, high voltage protection upgrades, AvistaUtilities.com upgrades and mobility in the field projects.

General (Oregon):

ER 7001 Structures and Improvements – 2013: $243,000; 2014: $131,000
This is a group of capital maintenance projects that Facilities Management coordinates at the Spokane Central Operating Facilities and Avista branch facilities - offices and service centers.

ER 7006 Tools, Lab & Shop Equipment – 2013: $73,000; 2014: $70,000
Expenditures in this category include all large tools and instruments used throughout the company for natural gas and/or electric construction and maintenance work, distribution, transmission, or generation operations, telecommunications, and some fleet equipment (hoists, winch, etc) not permanently attached to the vehicle.

ER 7101 HVAC Renovation Project – 2013: $609,000
The heating, ventilating, and air conditioning systems throughout the Spokane Central Operating Facilities are approximately fifty years old and are in need of replacement. In 2007, the Company initiated a multi-year HVAC renovation project that involved replacing central air handling units and distribution systems in three buildings - the Spokane Service Center, the general office building, and the cafeteria auditorium building. The building envelope of the general office building was also renovated with high efficiency glass and insulation. The project will also achieve asbestos abatement and life safety (fire sprinkler) additions. New controls will also be installed which will enable energy conservation.

ER 7126 Long Term Campus Re-Structuring Plan –2013: $457,000
The campus restructuring plan is a 2-year, 3 phase plan to address critical parking and office space needs. Avista employees are forced to park on residential streets which sometimes disturbs our neighbors. Moreover, Avista does not meet the current city requirements for handicap and carpool parking spaces. The campus restructuring will create 109 additional parking spaces for employees inside of the Avista property. Avista is currently leasing office space for 75 employees that cannot fit into the current facility layout. In 2013, Facilities will remodel the old warehouse to then accommodate 120 cubicles, meeting rooms, offices and restroom facilities. By remodeling the old warehouse, Avista will make wise use of the square footage and return employees to a central location. The budget for the warehouse renovation is $5,000,000.

ER 7127 CNG Fleet conversion–2013: $134,000; 2014: $9,000
The Company will be purchasing 41 new 1/2 ton, extra cab, 4 wheel drive Company owned trucks to assign to Construction Project Coordinators’ throughout Avista’s service territory. This project will have a 3 year timeframe. These trucks will run on CNG (Compressed Natural Gas).

Other Small Projects – 2013: $64,000; 2014: $61,000
These projects include stores equipment, productivity initiatives, craft training software, office and other general facility upgrades.

Transportation (Oregon):

ER 7000 Transportation Equipment – 2013: $885,000; 2014: $249,000
Expenditures are for the scheduled replacement of trucks, off-road construction equipment and trailers that meet the Company's guidelines for replacement including age, mileage, hours of use and overall condition. In addition, includes additions to the fleet for new positions or crews working to support the maintenance and construction of our natural gas operations.

Natural Gas Distribution (Oregon):

ER 1001 Gas Revenue Projects – 2013: $3,043,000; 2014: $1,004,000
This annual project will install sections of gas piping, meters, regulators, etc. that are directly linked to new revenue.

ER 3000 Gas Reinforcement – Minor Blanket - 2013: $131,000; 2014: $80,000
Avista has an obligation to provide reliable gas service that is of adequate pressure and capacity. Periodic reinforcement of the system is required to reliably serve increased demand at existing service locations and new customers. This annual program will identify and install new sections of gas main to improve the operating reliability and performance of the gas distribution system. Execution of this program on an annual basis will ensure the continuation of reliable gas service that is of adequate pressure and capacity.

ER 3001 Replace Deteriorated Pipe - 2013: $736,000; 2014: $216,000
This annual project will replace sections of existing gas piping that are suspect for failure or have deteriorated within the gas system. This project will address the replacement of sections of gas main that no longer operate reliably and/or safely. Sections of the gas system require replacement due to many factors including material failures, environmental impact, increased leak frequency, or coating problems. This project will identify and replace sections of main to improve public safety and system reliability.

ER 3002 Regulator Station Reliability Projects - 2013: $239,000; 2014: $64,000
This annual program will replace or upgrade existing regulator stations and meter stations to current Avista standards. This program will address enhancements that will improve system operating performance, enhance safety, replace inadequate or antiquated equipment that is no longer supported, and ensure the reliable operation of metering and regulating equipment.

ER 3003 Gas Replacement Street and Highways - 2013: $1,940,000; 2014: $698,000
This annual project will replace sections of existing gas piping that require replacement due to relocation or improvement of streets or highways in areas where gas piping is installed. Avista installs many of its facilities in public right-of-way under established franchise agreements. Avista is required under the franchise agreements, in most cases, to relocate its facilities when they are in conflict with road or highway improvements.

After the Company finalized its revenue requirement in this case, additional capital expenditures were approved for 2013 totaling approximately $1,200,000, making the new total for 2013 $3,140,000. The Company will provide updated workpapers and information including this investment during the process of this case.

ER 3004 Cathodic Protection Projects - 2013: $121,000; 2014: $54,000
This annual program will replace existing and install new cathodic protection systems to ensure compliance with 49 CFR 192, Subpart I - "Requirements for Corrosion Control" that requires pipelines be protected against external corrosion by means of a cathodic protection system. This program will ensure appropriate cathodic protection levels are maintained, reduce corrosion related failures, help prevent leaks within steel pipeline systems and enhance public safety.

ER 3005 Gas Distribution Non-Revenue Projects - 2013: $2,943,000; 2014: $903,000
This annual project will replace sections of existing gas piping that require replacement to improve the operation of the gas system but are not directly linked to new revenue. The project includes relocation of main related to overbuilds [customer constructed improvements (i.e. decks, driveways, etc.) that restricts the Company's access to pipe], improvement in equipment and/or technology to improve system operation and/or maintenance, replacement of obsolete facilities, replacement of main to improve cathodic performance, and projects to improve public safety and/or improve system reliability.

ER 3006 Overbuild Pipe Replacement Projects - 2013: $878,000; 2014: $388,000
This annual project will replace sections of existing gas piping that have experienced encroachment or have been overbuilt. It will address the replacement of sections of gas main that no longer can be operated safely and will identify and replace sections of main to improve public safety. All types of overbuilds will be addressed with the primary focus of the project being overbuilds in manufactured home developments.

ER 3007 Isolated Steel Replacement - 2013: $881,000; 2014: $531,000
This annual program will replace sections of cathodically isolated steel pipe. Isolated portions of pipe including risers, service pipe and main will be replaced as required to meet the requirements of 49 CFR 192.455 & 157. This program will be conducted in WA and ID also to assure cathodically isolated steel is identified and replaced as needed.

ER 3008 Aldyl-A Replacement Project - 2013: $4,100,000; 2014: $2,026,000
Avista is undertaking a planned twenty-year program to systematically remove and replace select portions of the DuPont Aldyl A medium density polyethylene pipe in its natural gas distribution system. Due to the tendency for this material to suffer brittle-like cracking leak failures, Aldyl A will eventually reach a level of unreliability that is not safe. There is a potential harm to the public through damage to life and property. After the Company finalized its revenue requirement in this case, more information regarding 2013 and 2014 capital expenditures became available. The 2013 Oregon costs will increase $250,000 and the estimated capital expenditures for 2014 could increase beyond what is included in this filing and will be updated during the process of this case. Also, of

the total $4,100,000 listed above for 2013, approximately $2,187,123 has transferred to plant during the six months ended June 30, 2013. This large replacement project is described further in the testimony of Mr. La Bolle.

ER3203 East Medford Reinforcement - 2013: $687,000

This project will install a 12" high-pressure steel pipeline from North Phoenix Road, ending in White City, OR. The total length of the line will be approximately 12.3 miles. As of July 2013 approximately 8.9 miles of this total project has been completed and transferred to service. Avista's Gas Integrated Resource Plan requires increased natural gas deliveries from the TransCanada Pipeline source at Phoenix Road Gate Station in SE Medford. Existing distribution piping exiting the station will be unable to receive the increased natural gas volumes. A new high-pressure natural gas line encircling Medford to the east and tying into an existing high pressure main in White City will improve delivery capacity and provide a much needed reinforcement in the East Medford area which is forecasting higher growth. The total of $687,000 transferred to plant in March of 2013. The remaining 3.4 miles of project is scheduled to start in 2018, and is not included in this case.

ER 3293 Klamath Falls Lateral Purchase - 2013: $2,650,000

The Company purchased the Klamath Falls lateral from Northwest Pipeline effective January 1, 2013. This project was approved for rate recovery in Order 12-429 on November 7, 2012, in Docket No. UG-228, with rates effective on January 1, 2013 coincident with the purchase date. The Company is currently passing through to customers the net benefits associated with the Company’s purchase of the Klamath Falls Lateral. This benefit is administered through Rate Schedule 498, and includes both the revenue requirement associated with the purchase and the reduction in firm demand costs. The Company is seeking recovery of the Klamath Falls Lateral revenue requirement in base rates. To avoid double recovery of the revenue requirement, the Company is proposing to cancel Schedule 498 as a part of its compliance filing when base rates change in this general rate case. The testimony of Company witnesses Mr. Harper and Mr. Ehrbar provide further detail on this purchase.

Other Small Projects – 2013: $888,000; 2014: $488,000

These projects include meters, regulators, ERTs and Jackson Prairie Storage capital expenditures.

V. SUMMARY OF ADJUSTMENTS

Q. What was the net impact to natural gas <u>rate base</u> for the capital adjustments forecasted in this case?

A. Natural gas net rate base for capital investment increased $23,632,000, from AMA results of operations balance of $138,669,000 to a forecasted June 30, 2014 balance of 162,301,000. Table 3 below summarizes the adjustments included in the case.

Table 3
Summary of Adjustments

($000's)		Adjustment 1 (2.05)		Adjustment 2 (2.06)		Adjustment 3 (2.07)			Adjustment 4 (2.08)	
	Rate Base 2012 AMA	Adjust 2012 to EOP Basis	Rate Base 12/31/12 EOP	Adjust 12/31/12 Vintage to 12/31/13 EOP	2013 Capital Additions to 12/31/13 EOP	Adjust 12/31/12 Vintage to June 30, 2014 EOP	2013 Capital Additions to June 30, 2014 EOP	2014 Capital Additions to June 30, 2014 EOP	Depreciation Study Adjustment impact EOP	Forecasted Rate Base June 30, 2014 EOP
Plant	$ 270,276	$ 4,121	$ 274,397	$ -	$ 24,437	$ -	$ -	$ 13,744	$ -	$ 312,578
A/D	(94,666)	(1,152)	(95,818)	(5,979)	(357)	(3,634)	(454)	(402)	(740)	$(107,384)
DFIT	(36,941)	(1,393)	(38,334)	(1,957)	(471)	(755)	(400)	(717)	(259)	$ (42,893)
Rate Base	$ 138,669	$ 1,576	$ 140,245	$ (7,936)	$ 23,609	$ (4,389)	$ (854)	$ 12,625	$ (999)	$ 162,301

Company witness Ms. Andrews includes the following four adjustments in her testimony and exhibits:

<u>2012 Capital Activity Adjustment</u> – Adjusts the 2012 test period rate base stated on an AMA basis to an EOP basis. The revenue-producing distribution plant of the 2012 capital additions were adjusted to EOP, to maintain the matching of revenues and costs associated with these assets.

<u>2013 Capital Activity Adjustment</u> – First, the plant that was in service at December 31, 2012, was depreciated through 2013, adjusting accumulated depreciation and DFIT to a December 31, 2013 EOP basis. Second, 2013 capital additions were forecasted on a December

31, 2013 EOP basis.

<u>2014 Capital Activity Adjustment</u> – First, the plant that was in service at December 31, 2012, was depreciated through June 30, 2014 adjusting accumulated depreciation and DFIT to a June 30, 2014 EOP basis. Second, the 2013 forecasted capital additions were depreciated through June 30, 2014, adjusting accumulated depreciation and DFIT to a June 30, 2014 EOP basis. Third, transfers to plant in service during the six months ended June 30, 2014 were forecasted on a June 30, 2014 EOP basis.

<u>Depreciation Study Adjustment</u> - The Company had new depreciation rates approved in Docket UM-1626, described further below. The depreciation rates for general plant were changed effective January 1, 2013, as approved in the first phase of the settlement. The depreciation rates for Oregon direct natural gas plant will be implemented with the effective date of customer's rates from this case. For the Company forecasted depreciation study adjustment, the Company annualized the depreciation expense for the forecasted rate period. Depreciation expense was computed using the new depreciation rates on all plant expected to be in service at December 31, 2013. This adjustment reflects the impact to accumulated depreciation and DFIT by changing the depreciation rates.

Q. What is the impact to <u>expense</u> for the forecasted test period?

A. Depreciation expense and property taxes increased approximately $2,148,000, before federal income taxes, for the capital additions pro formed in this case. As described below, this does not include the impact of changing depreciation rates at the conclusion of this rate case. This total represents the sum of expense adjustments 2.05 through 2.07 listed in Ms. Andrews' workpapers.

Capital Projects

VI. DEPRECIATION STUDY

Q. Please summarize the outcome of the Company's most recently completed depreciation study.

A. The Company was authorized to change its depreciation rates by the Oregon Commission in Order 13-168, dated May 6, 2013 (Docket No. UM 1626) in two phases[4]. The first phase approved common plant (allocated) depreciation rates, including transportation vehicles, as described below, to commence with the Company's Washington and Idaho jurisdictions' implementation on January 1, 2013. The second phase approved implementation of depreciation rates on plant directly assigned to Oregon, and will be effective with the effective date of new customer base rates at the conclusion of this general rate case.

Q. What is the impact of changing depreciation rates on depreciation expense for the forecasted test period?

A. Depreciation expense increased $1,705,627 due to the change in depreciation rates approved by the Oregon Commission for all plant that will be in service at December 31, 2013. This represents $238,287 on common plant, $226,451 on transportation vehicles, for which the Company changed depreciation rates effective January 1, 2013, and an additional $1,240,889 for Oregon direct plant, which will take effect at the conclusion of this rate case. These amounts are reflected in the Depreciation Study Adjustment (2.08) in Company witness Ms. Andrews' workpapers and exhibits.

Q. Please describe the computation of the depreciation study adjustment?

A. The Depreciation Study Adjustment (2.08) was computed as follows:

[4] The Company was last authorized to change its depreciation rates on January 1, 2008, per Order 08-182, dated March 31, 2008 (Docket No. UM 1351).

Plant in Service at December 31, 2012 – Depreciation expense for the 2014 rate year was computed using the new approved depreciation rates for all plant, excluding transportation vehicles, in service at December 31, 2012. Please see this computation in Adjustment 2.05 – 2012 Capital Activity in Ms. Andrews' workpapers. For the 2014 capital additions included in this case, depreciation expense was computed at the new approved depreciation rates, and therefore, are not part of the depreciation study adjustment.

2013 Capital Additions - Depreciation expense for the 2014 rate year was computed using the new approved depreciation rates for all 2013 capital additions pro formed in this case. Please see this computation in Adjustment 2.06 – 2013 Capital Activity in Ms. Andrews' workpapers.

Transportation Vehicles - Depreciation expense for the 2014 rate year was computed using the new approved depreciation rates for all transportation vehicles in service at December 31, 2012. Please see this computation in Adjustment 2.08 – Depreciation Study in Ms. Andrews' workpapers. These workpapers show a system increase of approximately $4.3 million to depreciation expense on transportation vehicles due to changing depreciation rates. Using the Company's method for allocating these costs to projects, including both capital and O&M projects, the impact to Oregon is an increase of $226,451 of depreciation expense that will be recorded as O&M and an increase of $22,972 of depreciation expense that will be recorded as capital. The Company used the actual allocation that occurred in 2012 to determine the impact in 2014.

VII. 2015 CAPITAL ADDITIONS

Q. Why has Avista included information regarding 2015 capital additions?

A. The Company has included 2015 information regarding capital additions to provide an indication of the Company's need for additional rate relief beyond June 30, 2014. The

2015 plant additions have been included for information purposes only and have not otherwise been included in the Company's request. As discussed further in Ms. Andrews and Mr. Thies' testimony, the Company's plans call for significant capital expenditure requirements over the next five years.

Q. How were the Capital Additions for 2015 computed?

A. The forecasted capital investment for 2015 was derived as a part of the capital budget process that was completed in the fall of 2012. The Company is currently updating its capital budget numbers, and the amounts included for 2015 are expected to increase beyond what has been discussed in this case. The current forecasted capital additions for 2015 have been previously approved by the Board of Directors. The Company will update the information discussed in this case for 2015 capital additions, once the capital budget is approved by the Board of Directors in September of this year.

Q. What are the Company's expected 2015 capital expenditures?

A. As shown in Table 4 below, Avista forecasts system-wide general plant capital expenditures of $44.514 million for the twelve months ended June 30, 2015 (Oregon share totals $3.846 million).

Table 4
General Plant Capital Expenditures in 000's

Project	June 30, 2015 System	June 30, 2015 Oregon Allocated
Security Initiative	$ 517	$ 41
Information Technology Refresh Projects-Software	13,525	1,078
Information Technology Expansion Projects-Software	4,958	397
Security Systems	1,433	114
Next Gen Radio	1,288	98
Microwave Replacement with Fiber	1,265	100
Transportation Equipment	5,825	463
Structures and Improvements	3,053	243
Tools Lab & Shop Equipment	1,672	133
COF HVAC Improvement	5,104	710
Long Term Campus Re-Structuring Plan	1,872	154
CNG Fleet Conversion	207	16
Small Technology Projects	2,358	185
Small General Projects	1,437	114
TOTAL	$ 44,514	$ 3,846

As shown in Table 5 below, Avista forecasts Oregon natural gas distribution capital expenditures of $12.510 million for the twelve months ended June 30, 2015.

Table 5
Oregon Gas Distribution Capital Expenditures in 000's

Project	June 30, 2015
Oregon - Gas Revenue Projects	$ 2,015
Gas Reinforce - Minor Blanket	148
Replace Deteriorating Gas System	506
Regulator Reliable -Blanket	118
Gas Replace - Street & Highway	1,291
Cathodic Protection - Minor Blanket	100
Gas Distribution Non-Revenue Projects	1,699
Overbuilt Pipe Replacement Projects	717
Isolated Steel	983
Aldyl-A Pipe Replaement	3,795
Other small gas Projects	1,138
TOTAL	$ 12,510

Tables 4 and 5 above detail the capital projects that will be transferred to plant in service from July 1, 2014 through June 30, 2015. The items listed in these tables have the same or similar descriptions as those provided for the 2013 and June 30, 2014 additions discussed earlier in my testimony.

Q. What was the net impact to natural gas rate base for capital expenditures forecasted between June 30, 2014 and June 30, 2015?

A. Natural gas net rate base for capital investment increased $5,387,000 from June 30, 2014 EOP balance of 162,301,000 to $167,688,000 at EOP June 30, 2015. Table 6 below summarizes the impact at June 30, 2015.

Table 6

2015 Adjustment Summary

($000's)

	Forecasted Rate Base June 30, 2014 EOP	Adjust 12/31/12 Vintage to June 30, 2015 EOP	2013 Capital Additions to June 30, 2015 EOP	2014 (Jul-Dec) Capital Additions to June 30, 2015 EOP	2015 Capital Additions to June 30, 2015 EOP	Forecasted Rate Base June 30, 2015 EOP
Plant	$ 312,578	$ -	$ -	$ 7,499	$ 8,857	$ 328,934
A/D	(107,384)	(7,268)	(908)	(233)	(82)	(115,875)
DFIT	(42,893)	(1,477)	(703)	(219)	(79)	(45,371)
Rate Base	$ 162,301	$ (8,745)	$ (1,611)	$ 7,047	$ 8,696	$ 167,688

VIII. CONCLUSION

Q. Please summarize Avista's proposal regarding the capital additions to rate base that has been included in the Company's filing.

A. Using an end of period balance midway through 2014, best reflects the conditions during the time new rates will be in effect, as well as the end of the statutory period for this case. Including the costs associated with the Company's forecasted 2014 capital investment in retail rates provides a proper "matching" of revenues from customers with the costs associated with providing service to customers, including the cost of utility plant used to serve customers. All plant included in the Company's request will be used and useful during the second half of the 2014 forecasted test year. Without the forecasted capital additions, the Company would not have the opportunity to earn its allowed rate of return on investment during the rate year.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF JOSEPH D. MILLER
REPRESENTING AVISTA CORPORATION

Long-Run Incremental Cost

I. INTRODUCTION

Q. Would you please state your name, business address and present position with Avista Corporation?

A. My name is Joseph D. Miller. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your responsibilities?

A. I am responsible for preparing data for and maintaining the regulatory natural gas cost of service models for the Company. I also provide support in the preparation of revenue analysis, rate spread and rate design, and miscellaneous other duties as required.

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

A. I am a 1999 graduate of Portland State University with a Bachelors degree in Business Administration, majoring in Accounting. In 2005 I graduated from Gonzaga University with a Masters degree in Business Administration. I joined the Company in March 2008 after spending eight years in both the public and private accounting sector. I started with Avista as a Natural Gas Accounting Analyst in the Company's Resource Accounting department. In January 2009, I joined the State and Federal Regulation Department as a Regulatory Analyst. My primary responsibility was coordinating discovery for the Company's general rate case filings. In my current role as a Senior Regulatory Analyst, I am responsible for the Company's natural gas cost of service studies in all jurisdictions, among other things.

Q. Would you please briefly summarize your testimony?

A. My testimony presents the natural gas cost of service study prepared for this filing. The results of the long-run incremental cost study indicate that at current rates, on a relative margin to cost basis, residential and interruptible customers are generally in line with relative cost of service, small commercial customers are paying less than their relative cost of service, while large general, seasonal, and transportation customer groups exceed their relative cost of service to varying degrees. Company witness Mr. Ehrbar uses the results of the study as a guide to spread the proposed increase by service schedule.

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

A. Yes. I am sponsoring Exhibit No. 801, which is the Company's long-run incremental cost (LRIC) study and Exhibit No. 802, which shows the functional component classification of the Company's proposed revenue requirement in this case.

Q. Were these exhibits prepared by you?

A. Yes.

II. LONG-RUN INCREMENTAL COST 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 by rate schedule. When applied to current results of operations, the study indicates the adequacy of current rates compared to costs. The study results are used as one of the guidelines in determining the appropriate rate spread among rate schedules.

Q. 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 natural gas supplied to a customer. All of the information is accumulated in terms of cost per customer for an average or typical customer on each rate schedule and then summarized to represent the long-run incremental cost of the 2014 total pro forma customers and therms.

<u>Incremental Investment Costs</u>

Q. What is included in incremental plant investment?

A. Incremental plant investment is segregated into three separate categories which are summarized below and discussed in further detail later in my testimony.

<u>New Customer Related Plant Investment:</u>

- Natural gas main extension to reach the customer;
- Service line to connect the customer to the main;
- Metering equipment at the customer's premises;

<u>System Main Related Plant Investment:</u>

- Capacity reinforcements to maintain system planning requirements in order to meet the peak needs of all customers (capacity related investment);
- Mandated safety and reliability requirements for the benefit of all customers (commodity related investment);
- Long-run incremental <u>capacity</u> and <u>commodity</u> system main replacement investment;

<u>Underground Storage Plant Investment</u>

- Oregon's share of the Company's investment in underground storage facilities.

Q. Are these items identified in the cost study presented in this case?

A. Yes. Exhibit No. 801 page 2 shows the calculation of the 2014 cost per customer of the various investment costs included in this study. System core main investments have been categorized into capacity or commodity unit costs.

Q. How are new customer related plant investments quantified in this study?

A. Typical natural gas main extensions are quantified in terms of the size and length of pipe recently provided for customers, multiplied by recent costs for each pipe size. A summary of the last seven years of Oregon project work orders were used to identify the average length and typical size of pipe to serve different residential and small commercial 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 transportation customers, who have a feasible option to direct-connect to the interstate pipeline, were assigned the estimated bypass cost. For large general service customers on Schedule 424, a random sample comprising approximately 25% of the population was selected. Using the facilities mapping system and the in-service date of the mains, the length and size of apparent line extensions associated with the randomly selected customers were identified and current costs applied to determine the sample line extension cost per customer for this group, and the resulting values were also used for the seasonal customers on Schedule 444.

Service lines were quantified by the size of pipe typically needed for the type of customer. For large general service, interruptible and transportation customers, the sample analysis and identified dedicated pipe were used to determine average current cost, similar to the main extension cost assignment.

Metering equipment was quantified by a weighted average current meter cost per customer. The weighted average captures the actual equipment types in service on each rate schedule priced at the 2012 average installed cost. For transportation customers, $1,000 was added to approximate the additional cost of telemetering equipment required for transportation service.

Q. You stated that system main related plant investment costs were simplified into capacity-related and commodity-related investments. Would you please explain what is included in these categories?

A. Yes. First, the Company's Oregon (non-revenue producing) distribution system investment projects were segregated into reinforcement projects versus safety and reliability projects based on the capital project categories described in Company witness Mr. DeFelice's testimony. A four-year average (2 years actual and 2 years budget) annual investment total was determined for the two types of projects. The reinforcement projects are considered capacity-related and therefore were divided by estimated Oregon total design day usage in therms. The safety and reliability projects are considered commodity-related and therefore were divided by annual therms.

Long-run replacement cost was estimated by computing the current cost of all Oregon mains in service at December 31, 2012 by size and type. The current cost already accounted for by customer main extensions, reinforcement projects, and safety/reliability projects were deducted to determine remaining system replacement investment. The remaining value was segregated into capacity versus commodity by the 2012 peak and average ratio. The capacity portion was then divided by estimated Oregon total design day usage and the commodity portion was divided by annual therms.

Q. How was the 2014 incremental capacity-related investment per customer quantified?

A. The sum of the Investment per Design Day therm for reinforcement projects and the capacity-related portion of system replacement were divided by days in the year to arrive at a 100% load factor cost per therm shown on line 13 of page 2 of Exhibit No. 801. This cost per therm has been adjusted for each rate schedule, based on the average estimated design day load factor for customers served under the schedule. Customers' design day load characteristics are the primary criteria associated with system capacity planning. The rate schedule cost per therm is then applied to average annual consumption per customer to get capacity main investment per customer for each schedule.

Q. How was the 2014 incremental commodity-related main investment per customer quantified?

A. The investment per therm for safety and reliability projects and the commodity-related portion of system replacement are added together to determine the incremental commodity main investment per therm. This per therm cost is then multiplied by the average annual consumption per customer to get the capacity-related main investment per customer for each schedule.

Q. How was underground storage plant investment quantified?

A. The Oregon jurisdictional underground storage plant balance at December 31, 2012 was used to represent investment in underground storage facilities. The assignment of costs associated with Oregon's share of the Jackson Prairie Storage facility recognizes that storage provides benefits to customers both through the mitigation of natural gas commodity costs and pipeline balancing. The assignment related to the Jackson Prairie Storage facility was split based on an 87% sales commodity and 13% throughput (balancing) basis. This relationship has been utilized in this cost study by determining the cost per therm based on throughput of 13% of the investment, and the cost per therm based on sales volumes of the remaining 87% of the investment. These unit costs are then multiplied by the average use per customer to determine the investment per customer for each schedule.

Q. Does the methodology related to the assignment of costs related to underground storage differ from prior cases?

A. No, it does not.

Q. Exhibit No. 801 page 2 shows a "levelized plant cost factor" for each investment. What is the purpose of this factor?

A. The levelized plant cost factor is an annual carrying charge applied to plant investments. There is a different factor for services, meters, mains and underground storage based on different estimated lives.

Q. How are the levelized plant cost factors determined?

A. A "Revenue Requirement Model" is used to determine the levelized revenue requirement (annual cost) associated with incremental plant over the estimated life of the asset. The model accounts for all costs and expenses associated with owning and maintaining the asset.

<u>Operating Expenses</u>

Q. What is included in gas supply and customer service related incremental operating and maintenance expenses?

A. This category captures the current costs associated with 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 No. 801 page 3 itemizes the various operating and maintenance expenses included in this study.

Q. Please explain the items shown on Exhibit No. 801 page 3.

A. Gas supply schedulers schedule and track all the natural gas being delivered at all delivery points on the system, including the natural gas owned by transportation customers. The majority of their time is spent for the benefit of core customers, however, transportation customers require individual attention. A proportion of their time devoted to providing services for transportation versus core customers was applied to the scheduler's hours charged to FERC Account 813 "Other Gas Expenses" during 2012, 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 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 2012 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 2012 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 natural gas?

A. The cost of gas includes all of the items included in the Purchased Gas Cost Adjustment provision rate Schedule 461, excluding the Gross Revenue Factor. These include the entire commodity, demand and upstream transportation charges (including the benefits of storage) the Company passes through to customers. The gas commodity costs shown on Exhibit No. 801, page 1, line 4, reflect the rates approved as a result of the most recent purchased gas adjustment (PGA) filing that went into effect November 1, 2012, grossed up for the revenue related expenses shown in Company witness Ms. Andrews revenue conversion factor.

Results Analysis

Q. What is shown on Exhibit No. 801, Page 1 entitled "Result Summary"?

A. The first three lines present the pro forma rate year usage and customer statistics relevant to the study. The next section, beginning on line 5 and ending on line 16, shows the pro forma rate year incremental costs for each component in the study. All items include revenue related expenses either through an after the fact gross up or embedded in the carrying charge on investment costs. The Long Run Incremental Distribution Cost on Line 17 is the sum of all the components (excluding natural gas commodity costs). Beginning on line 20 the study brings in the Company revenue requirement segregated into components comparable with the LRIC components shown above. Each component cost is then assigned to the rate schedules based on the LRIC results for the equivalent component. Once all of the components have been assigned, the results for each schedule are summed to produce the LRIC Based Target Margin on line 27. Following this are the resulting Current Margin to Target Margin ratios stated both in the absolute (Line 29) and on a relative basis (Line 29A). LRIC Based Target Margin results in an Oregon Total margin to cost ratio (shown on line 29) of 0.82. On line 28, I also included a comparison of Total Current Revenue to Total Proposed Cost, which includes the cost of gas in both the numerator and denominator. The Component LRIC Target Increase by Schedule, on line 30, represents the margin revenue (including the proposed increase) required from each schedule that would be perfectly aligned with the cost study. Mr. Ehrbar uses the Relative Margin to Cost at Present Rates, on line 29A, as a guide to spread the proposed increase by service schedule.

Q. Where did the revenue requirement components come from?

A. Exhibit No. 802 shows how the pro forma results of operations, including the requested revenue increase from Company witness Ms. Andrews Exhibit No. 601, have been assigned to the functional component classifications used in the cost of service.

Q. What are the results of the Company's LRIC study?

A. The following table shows the relative margin-to-cost ratio at present rates for each rate schedule:

Table 1 Long Run Incremental Cost Study

Customer Class	LRIC Summary Component Allocation Relative Margin-to-Cost Present Rates
Residential Service Schedule 410	0.99
General Service Schedule 420	0.93
Large General Service Schedule 424	1.47
Interruptible Sales Service Schedule 440	1.01
Seasonal Sales Service 444	1.12
Special Contracts Schedule 447	0.87
Transportation Service Schedule 456	1.58
Total Oregon Gas	1.00

The present relative margin-to-cost ratios indicate that general service (primarily commercial) customers on Schedule 420 are paying somewhat less than their relative cost of service, while large general (Schedule 424), seasonal (Schedule 444) and transportation (Schedule 456) service customers are paying somewhat more than their relative cost of service. Residential service customers on Schedule 410 and interruptible customers on Schedule 440 are not far from parity on a relative margin to cost basis. The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. Please summarize your testimony regarding the LRIC study.

A. I have provided a long-run incremental cost study by service schedule for the Company's Oregon jurisdiction. The study incorporates the essential elements of providing service to customers over the long term. As a guideline for the proposed rate spread, the study indicates that it would be reasonable for small general service customers on Schedule 420 to receive a somewhat larger percentage margin increase than other customer groups, and large general service, seasonal, and transportation customers on Schedules 424, 444 and 456 to receive a smaller percentage margin increase than other customer groups. This is reflected in Mr. Ehrbar's proposed rate spread.

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

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

JOSEPH D. MILLER
Exhibit No. 801

Long-Run Incremental Cost

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2014

RESULT SUMMARY *(Component Allocation)*

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS								
1	2014 ANNUAL THERM DELIVERIES	119,557,603	48,912,477	26,046,807	4,098,586	2,536,455	238,479	7,350,651	30,374,148
2	2014 CUSTOMERS	96,953	85,557	11,231	80	35	9	4	37
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		572	2,319	51,286	72,470	26,498	1,837,663	819,078
4	Gas Commodity Costs	$ 57,140,000	34,655,000	18,455,000	2,904,000	957,000	169,000	-	-
5	Gas Scheduling 1.03031	$ 43,321	27,465	3,605	26	1,426	3	1,051	9,745
6	Gas Planning	$ 121,278	107,023	14,048	100	44	11	5	46
7	Meter Reading	$ 117,929	103,957	13,646	97	100	11	11	106
8	Billing	$ 2,282,665	2,010,717	263,938	1,878	2,724	212	311	2,886
	Customer Installation Investment Cost								
9	Meters	$ 4,398,289	3,111,372	1,153,403	41,039	22,390	5,425	14,463	50,198
10	Services	$ 13,939,585	12,060,504	1,343,181	125,788	111,435	14,166	29,045	255,467
11	Main Extensions 100%	$ 96,144,833	58,155,842	36,472,908	476,000	179,918	53,606	238,498	568,061
12	Total Customer Installation Investment Cost	$ 114,482,707	73,327,717	38,969,491	642,827	313,743	73,197	282,006	873,726
	System Core Main Cost								
13	Capacity	$ 13,464,961	6,678,889	3,267,892	290,641	135,962	-	285,217	2,806,360
14	Commodity	$ 14,444,681	5,911,510	3,145,968	495,086	306,388	28,807	887,913	3,669,009
15	Total Core Main Cost	$ 27,909,642	12,590,399	6,413,859	785,727	442,349	28,807	1,173,131	6,475,369
16	Underground Storage Cost	$ 1,041,021	596,863	317,637	49,987	30,935	2,909	8,318	34,372
17	Long Run Incremental Distribution Cost	$ 145,998,563	88,764,141	45,996,224	1,480,642	791,322	105,149	1,464,834	7,396,251
18	Revenue at Present Rates	$ 99,358,000	62,855,000	28,616,000	3,535,000	1,221,000	207,000	279,000	2,645,000
19	**Margin Revenue at Present Rates**	**$ 42,218,000**	**28,200,000**	**10,161,000**	**631,000**	**264,000**	**38,000**	**279,000**	**2,645,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
20	Cost of Gas Commodity	$ 57,140,000	34,655,000	18,455,000	2,904,000	957,000	169,000	-	-
21	Scheduling and Planning Costs	$ 597,000	487,787	64,030	456	5,332	51	3,831	35,514
22	Meter Reading, Billing, Etc. Costs	$ 3,569,000	3,143,918	412,688	2,937	4,198	331	480	4,448
23	Meters & Services Costs	$ 16,244,000	13,439,505	2,211,516	147,778	118,544	17,354	38,540	270,763
24	System Core Main Costs	$ 29,844,000	17,019,546	10,317,344	303,536	149,700	19,826	339,598	1,694,450
25	Underground Storage Costs	$ 1,445,000	828,482	440,899	69,385	42,939	4,037	11,546	47,711
26	Proposed Cost	$ 108,839,000	69,574,238	31,901,477	3,428,091	1,277,714	210,599	393,995	2,052,886
27	**LRIC Based Target Margin**	**$ 51,699,000**	**34,919,238**	**13,446,477**	**524,091**	**320,714**	**41,599**	**393,995**	**2,052,886**
28	Current Revenue to Proposed Cost (Includes Cost of Gas)	**0.91**	**0.90**	**0.90**	**1.03**	**0.96**	**0.98**	**0.71**	**1.29**
29	Current Margin Revenue to LRIC Based Target Margin	**0.82**	**0.81**	**0.76**	**1.20**	**0.82**	**0.91**	**0.71**	**1.29**
	29A **Relative Margin to Cost at Present Rates**	**1.00**	**0.99**	**0.93**	**1.47**	**1.01**	**1.12**	**0.87**	**1.58**
30	Component LRIC Target Increase by Schedule	$ 9,481,000	$ 6,719,238	$ 3,285,477	$ (106,909)	$ 56,714	$ 3,599	$ 114,995	$ (592,114)
31	Target Increase as Percent of Total Present Revenue	9.54%	10.69%	11.48%	-3.02%	4.64%	1.74%	41.22%	-22.39%
	31A Target Increase as Percent of Present Margin Revenue	22.46%	23.83%	32.33%	-16.94%	21.48%	9.47%	41.22%	-22.39%
32	Avg Cost Per Month for Meter Reading, Billing & Meters & Services		$ 16.15						

UG-246 Exhibit 801 Miller (Avista) (Aug2013).xlsm

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2014

INCREMENTAL INVESTMENT COSTS

Line No.			Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	SERVICE INSTALLATIONS	48 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	1"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	1/2" - 1.25"	1/2" - 1.25"
2	AVERAGE SERVICE COST		$ 786.19	$ 667.03	$ 8,778.51	$ 17,757.18	$ 8,778.51	$ 40,497.46	$ 38,421.57
3	LEVELIZED PLANT COST FACTOR		0.1793	0.1793	0.1793	0.1793	0.1793	0.1793	0.1793
4	ANNUAL REVENUE REQUIREMENT		$ 140.96	$ 119.60	$ 1,573.99	$ 3,183.86	$ 1,573.99	$ 7,261.19	$ 6,888.99
	METERS & REGULATORS	36 yr life							
5	METERS & REGULATORS		$ 194.47	$ 549.20	$ 2,746.13	$ 3,420.90	$ 3,223.31	$ 19,335.30	$ 7,238.83
6	LEVELIZED PLANT COST FACTOR		0.1870	0.1870	0.1870	0.1870	0.1870	0.1870	0.1870
7	ANNUAL REVENUE REQUIREMENT		$ 36.37	$ 102.70	$ 513.53	$ 639.71	$ 602.76	$ 3,615.70	$ 1,353.66
	MAIN INVESTMENT	58 yr life							
8	AVERAGE MAIN EXTENSION PER CUSTOMER		72	344	805	534	805	Estimated	1120
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	sample	dedicated plt	same as 424	Bypass Cost	dedicated plt
10	AVERAGE COST PER FOOT 2012		52.39	52.39	41.06	$ 53.42	41.06		$ 75.90
11	MAIN EXTENSION INVESTMENT		$ 3,772.08	$ 18,022.16	$ 33,053.30	$ 28,526.79	$ 33,053.30	$ 330,880.00	$ 85,008.28
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	22.93%	24.94%	44.13%	58.38%	0.00%	80.65%	33.87%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.173660	$ 0.757348	$ 0.696311	$ 0.393519	$ 0.297465	$ -	$ 0.215325	$ 0.512725
14	2014 AVERAGE THERMS PER CUSTOMER		572	2,319	51,286	72,470	26,498	1,837,663	819,078
15	CAPACITY MAIN INVESTMENT		$ 433.20	$ 1,614.75	$ 20,182.02	$ 21,557.28	$ -	$ 395,695.67	$ 419,961.87
16	INCR COMMODITY MAIN INVESTMENT PER THERM		0.670332	$ 0.670332	$ 0.670332	$ 0.670332	$ 0.670332	$ 0.670332	$ 0.670332
17	2014 AVERAGE THERMS PER CUSTOMER		572	2,319	51,286	72,470	26,498	1,837,663	819,078
18	SAFETY MAIN INVESTMENT		$ 383.43	$ 1,554.50	$ 34,378.65	$ 48,578.96	$ 17,762.46	$ 1,231,844.31	$ 549,054.19
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 4,588.71	$ 21,191.41	$ 87,613.97	$ 98,663.03	$ 50,815.76	$ 1,958,419.98	$ 1,054,024.34
20	LEVELIZED PLANT COST FACTOR	58 yr life	0.1802	0.1802	0.1802	0.1802	0.1802	0.1802	0.1802
21	ANNUAL REVENUE REQUIREMENT		$ 826.89	$ 3,818.69	$ 15,788.04	$ 17,779.08	$ 9,157.00	$ 352,907.28	$ 189,935.19
	UNDERGROUND STORAGE INVESTMENT								
22	BALANCING INVESTMENT PER THROUGPUT THERM		$ 0.006311	$ 0.006311	$ 0.006311	$ 0.006311	$ 0.006311	$ 0.006311	$ 0.006311
23	STORAGE INVESTMENT PER SALES THERM		$ 0.061709	$ 0.061709	$ 0.061709	$ 0.061709	$ 0.061709		
24	2014 AVERAGE THERMS PER CUSTOMER		572	2,319	51,286	72,470	26,498	1,837,663	819,078
25	UNDERGROUND STORAGE INVESTMENT		$ 38.91	$ 157.74	$ 3,488.51	$ 4,929.46	$ 1,802.41	$ 11,598.20	$ 5,169.52
26	LEVELIZED PLANT COST FACTOR	48 yr life	0.1793	0.1793	0.1793	0.1793	0.1793	0.1793	0.1793
27	ANNUAL REVENUE REQUIREMENT		$ 6.98	$ 28.28	$ 625.49	$ 883.85	$ 323.17	$ 2,079.56	$ 926.89
28	**TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER**		**$ 1,011.19**	**$ 4,069.27**	**$ 18,501.04**	**$ 22,486.50**	**$ 11,656.92**	**$ 365,863.73**	**$ 199,104.73**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2014

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	0.00794	0.00794	0.00794	1.00794	0.00794	6.50000	6.50000
2	AVERAGE RATE PER HOUR	$ 39.24	$ 39.24	$ 39.24	$ 39.24	$ 39.24	$ 39.24	$ 39.24
3	LABOR COST	$ 0.31157	$ 0.31157	$ 0.31157	$ 39.55157	$ 0.31157	$ 255.06000	$ 255.06000
	GAS MANAGEMENT (PLANNING)							
4	ANNUAL HOURS	0.020976	0.020976	0.020976	0.020976	0.020976	0.020976	0.020976
5	AVERAGE RATE PER HOUR	$ 57.88	$ 57.88	$ 57.88	$ 57.88	$ 57.88	$ 57.88	$ 57.88
6	LABOR COST	$ 1.21409	$ 1.21409	$ 1.21409	$ 1.21409	$ 1.21409	$ 1.21409	$ 1.21409
7	**TOTAL GAS SUPPLY O&M**	**$ 1.53**	**$ 1.53**	**$ 1.53**	**$ 40.77**	**$ 1.53**	**$ 256.27**	**$ 256.27**
	METER READING							
8	ANNUAL HOURS	0.04665	0.04665	0.04665	0.10526	0.04665	0.10526	0.10526
9	AVERAGE RATE PER HOUR	$ 25.28	$ 25.28	$ 25.28	$ 26.43	$ 25.28	$ 26.43	$ 26.43
10	LABOR COST	$ 1.17931	$ 1.17931	$ 1.17931	$ 2.78202	$ 1.17931	$ 2.78202	$ 2.78202
	CUSTOMER HANDBILLS							
11	ANNUAL HOURS	0.00000	0.00000	0.00000	1.87145	0.00000	1.87145	1.87145
12	AVERAGE RATE PER HOUR	$ -	$ -	$ -	$ 28.17	$ -	$ 28.17	$ 28.17
13	LABOR COST	$ -	$ -	$ -	$ 52.72	$ -	$ 52.72	$ 52.72
	BILLING							
14	ANNUAL POSTAGE PER CUST	$ 2.86	$ 2.86	$ 2.86	$ 2.86	$ 2.86	$ 2.86	$ 2.86
15	5 YR AVERAGE PER CUST	$ 19.95	$ 19.95	$ 19.95	$ 19.95	$ 19.95	$ 19.95	$ 19.95
16	BILLING COST	$ 22.81	$ 22.81	$ 22.81	$ 22.81	$ 22.81	$ 22.81	$ 22.81
17	**TOTAL CUSTOMER O&M**	**$ 23.99**	**$ 23.99**	**$ 23.99**	**$ 78.31**	**$ 23.99**	**$ 78.31**	**$ 78.31**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST STUDY
TWELVE MONTHS ENDED DECEMBER 2014

RESULT SUMMARY ***(Component Allocation)***

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS								
1	2014 ANNUAL THERM DELIVERIES	119,557,603	48,912,477	26,046,807	4,098,586	2,536,455	238,479	7,350,651	30,374,148
2	2014 CUSTOMERS	96,953	85,557	11,231	80	35	9	4	37
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		572	2,319	51,286	72,470	26,498	1,837,663	819,078
4	Gas Commodity Costs	$ 57,140,000	34,655,000	18,455,000	2,904,000	957,000	169,000	-	-
5	Gas Scheduling 1.03031	$ 43,321	27,465	3,605	26	1,426	3	1,051	9,745
6	Gas Planning	$ 121,278	107,023	14,048	100	44	11	5	46
7	Meter Reading	$ 117,929	103,957	13,646	97	100	11	11	106
8	Billing	$ 2,282,665	2,010,717	263,938	1,878	2,724	212	311	2,886
	Customer Installation Investment Cost								
9	Meters	$ 4,398,289	3,111,372	1,153,403	41,039	22,390	5,425	14,463	50,198
10	Services	$ 13,939,585	12,060,504	1,343,181	125,788	111,435	14,166	29,045	255,467
11	Main Extensions 100%	$ 96,144,833	58,155,842	36,472,908	476,000	179,918	53,606	238,498	568,061
12	Total Customer Installation Investment Cost	$ 114,482,707	73,327,717	38,969,491	642,827	313,743	73,197	282,006	873,726
	System Core Main Cost								
13	Capacity	$ 13,464,961	6,678,889	3,267,892	290,641	135,962	-	285,217	2,806,360
14	Commodity	$ 14,444,681	5,911,510	3,145,968	495,086	306,388	28,807	887,913	3,669,009
15	Total Core Main Cost	$ 27,909,642	12,590,399	6,413,859	785,727	442,349	28,807	1,173,131	6,475,369
16	Underground Storage Cost	$ 1,041,021	596,863	317,637	49,987	30,935	2,909	8,318	34,372
17	Long Run Incremental Distribution Cost	$ 145,998,563	88,764,141	45,996,224	1,480,642	791,322	105,149	1,464,834	7,396,251
18	Revenue at Present Rates	$ 99,358,000	62,855,000	28,616,000	3,535,000	1,221,000	207,000	279,000	2,645,000
19	**Margin Revenue at Present Rates**	**$ 42,218,000**	**28,200,000**	**10,161,000**	**631,000**	**264,000**	**38,000**	**279,000**	**2,645,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
20	Cost of Gas Commodity	$ 57,140,000	34,655,000	18,455,000	2,904,000	957,000	169,000	-	-
21	Scheduling and Planning Costs	$ 597,000	487,787	64,030	456	5,332	51	3,831	35,514
22	Meter Reading, Billing, Etc. Costs	$ 3,569,000	3,143,918	412,688	2,937	4,198	331	480	4,448
23	Meters & Services Costs	$ 16,244,000	13,439,505	2,211,516	147,778	118,544	17,354	38,540	270,763
24	System Core Main Costs	$ 29,844,000	17,019,546	10,317,344	303,536	149,700	19,826	339,598	1,694,450
25	Underground Storage Costs	$ 1,445,000	828,482	440,899	69,385	42,939	4,037	11,546	47,711
26	Proposed Cost	$ 108,839,000	69,574,238	31,901,477	3,428,091	1,277,714	210,599	393,995	2,052,886
27	**LRIC Based Target Margin**	**$ 51,699,000**	**34,919,238**	**13,446,477**	**524,091**	**320,714**	**41,599**	**393,995**	**2,052,886**
28	Current Revenue to Proposed Cost (Includes Cost of Gas)	**0.91**	**0.90**	**0.90**	**1.03**	**0.96**	**0.98**	**0.71**	**1.29**
29	Current Margin Revenue to LRIC Based Target Margin	**0.82**	**0.81**	**0.76**	**1.20**	**0.82**	**0.91**	**0.71**	**1.29**
	29A **Relative Margin to Cost at Present Rates**	**1.00**	**0.99**	**0.93**	**1.47**	**1.01**	**1.12**	**0.87**	**1.58**
30	Component LRIC Target Increase by Schedule	$ 9,481,000	$ 6,719,238	$ 3,285,477	$ (106,909)	$ 56,714	$ 3,599	$ 114,995	$ (592,114)
31	Target Increase as Percent of Total Present Revenue	9.54%	10.69%	11.48%	-3.02%	4.64%	1.74%	41.22%	-22.39%
	31A Target Increase as Percent of Present Margin Revenue	22.46%	23.83%	32.33%	-16.94%	21.48%	9.47%	41.22%	-22.39%
32	Avg Cost Per Month for Meter Reading, Billing & Meters & Services		$ 16.15						

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

JOSEPH D. MILLER
Exhibit No. 802

Long-Run Incremental Cost

AVISTA UTILITIES
NATURAL GAS RESULTS OF OPERATION
OREGON FORECASTED RESULTS
TWELVE MONTHS ENDED DECEMBER 31, 2014
(000'S OF DOLLARS)

Compute Functional Revenue Requirement

FUNCTIONAL CLASSIFICATION

Line No.	DESCRIPTION		Forecasted Total	Cost of Gas Commodity & Amortizations	Scheduling and Planning Costs	Meter Reading Billing, Etc Costs	Meters & Services Costs	System Core Main Costs	Underground Storage Costs
	a		-						
	REVENUES								
1	Revenue From Rates		$99,358	57,140	597	3,569	16,244	29,844	1,445
2	Proposed Increase		9,481						
3	Other Revenues		144				144		
4	Total Gas Revenues		108,983	57,140	597	3,569	16,388	29,844	1,445
	EXPENSES								
5	Exploration and Development		0						
	Production								
6	City Gate Purchases		55,459	55,459					
7	Purchased Gas Expense		0						
8	Other Gas Expenses		579		579				
9	Depreciation		0						0
10	Taxes		0						0
11	Total Production		56,038	55,459	579	0	0	0	0
	Underground Storage								
12	Operating Expenses		112						112
13	Depreciation		109						109
14	Taxes		7						7
15	Total Underground Storage		228	0	0	0	0	0	228
	Distribution								
16	Operating Expenses		7,143				2,532	4,611	
17	Depreciation		5,539				1,964	3,575	
18	Taxes		2,824				1,001	1,823	
19	Total Distribution		15,506	0	0	0	5,497	10,009	0
20	Customer Accounting		2,892			2,892			
21	Customer Service & Information		567			567			
22	Sales Expenses		5			5			
	Administrative & General								
23	Operating Expenses		7,480				2,594	4,723	164
24	Depreciation & Amortization		1,424				494	899	31
25	Taxes		1,977				686	1,248	43
26	Total Admin. & General		10,881	0	0	0	3,774	6,870	238
	Revenue Related Expenses								
	20 Uncollectibles	0.005329	580	305	3	19	87	159	7
	23 Commission Fees	0.002500	272	144	1	9	41	75	4
	23 ERSA	0.000751	82	43	0	3	12	22	1
	18 Franchise Fees	0.020842	2,269	1,191	12	74	339	622	30
27	Total Gas Expense	0.029422	89,320	57,142	597	3,569	9,749	17,757	508
28	OPERATING INCOME BEFORE FIT		19,663	(2)	0	0	6,639	12,087	937
	FEDERAL INCOME TAX								
29	Current and Deferred FIT		2,534	-	-	-	856	1,558	121
	Debt Interest		(288)				(97)	(177)	(14)
30	FIT on Revenue Increase	0.313885	2,976	-	-	-	1,005	1,829	142
31	State Income Tax		(55)	-	-	-	(19)	(34)	(3)
	SIT on Revenue Increase	0.073764	699	-	-	-	236	430	33
32	NET OPERATING INCOME		$13,797	($2)	$0	$0	$4,658	$8,481	$658
	Interest Expense	2.78%	4,898	0	0	0	1,654	3,011	233
	RATE BASE: PLANT IN SERVICE								
33	Production Plant		8						8
34	Underground Storage Plant		6,020						6,020
35	Transmission Plant		0						
36	Distribution Plant		268,640				95,239	173,401	
37	General Plant		37,486				12,998	23,664	823
38	Total Plant in Service		312,154	0	0	0	108,237	197,065	6,851
	ACCUMULATED DEPRECIATION								
39	Production Plant		0						0
40	Underground Storage Plant		(578)						(578)
41	Transmission Plant		0						
42	Distribution Plant		(94,387)				(33,462)	(60,925)	
43	General Plant		(11,577)				(4,014)	(7,309)	(254)
44	Total Accum. Depreciation		(106,542)	0	0	0	(37,476)	(68,234)	(832)
45	DEFERRED FIT		(44,560)				(15,451)	(28,131)	(978)
46	GAS INVENTORY		3,084						3,084
	PREPAID PENSION		5,710				1,980	3,605	125
47	WORKING CAPITAL		6,355				2,204	4,012	139
48	TOTAL RATE BASE		$176,201	$0	$0	$0	$59,494	$108,317	$8,389
49	RATE OF RETURN		7.83%	#DIV/0!	#DIV/0!	#DIV/0!	7.83%	7.83%	7.83%

Compute Functional Revenue Requirement

FUNCTIONAL CLASSIFICATION

Line No.	DESCRIPTION		Forecasted Total	Cost of Gas Commodity & Amortizations	Scheduling and Planning Costs	Meter Reading Billing, Etc Costs	Meters & Services Costs	System Core Main Costs	Underground Storage Costs
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24	Depreciation & Amortization		1,424				494	899	31
25	Taxes		1,977				686	1,248	43
26	Total Admin. & General		10,881	0	0	0	3,774	6,870	238
	Revenue Related Expenses								
	20 Uncollectibles	0.005329	580	305	3	19	87	159	7
	23 Commission Fees	0.002500	272	144	1	9	41	75	4
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49	RATE OF RETURN		7.83%	#DIV/0!	#DIV/0!	#DIV/0!	7.83%	7.83%	7.83%

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

DIRECT TESTIMONY OF PATRICK D. EHRBAR
REPRESENTING AVISTA CORPORATION

Forecast Revenue Load Adjustment, Rate Spread, and Rate Design

I. INTRODUCTION

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

A. My name is Patrick D. Ehrbar and my business address is 1411 East Mission Avenue, Spokane, Washington. My present position is Manager of Rates and Tariffs.

Q. Would you briefly describe your duties?

A. Yes. My primary areas of responsibility include electric and natural gas rate design, customer usage and revenue analysis, and tariff administration.

Q. Please briefly describe your educational background and professional experiences.

A. I am a 1995 graduate of Gonzaga University with a Bachelors degree in Business Administration. In 1997 I graduated from Gonzaga University with a Masters degree in Business Administration. I started with Avista in April 1997 as a Resource Management Analyst in the Company's DSM department. Later, I became a Program Manager, responsible for energy efficiency program offerings for the Company's educational and governmental customers. In 2000, I was selected to be one of the Company's key Account Executives. In this role I was responsible for, among other things, being the primary point of contact for numerous commercial and industrial customers, including delivery of the Company's site specific energy efficiency programs.

I joined the State and Federal Regulation Department as a Senior Regulatory Analyst in 2007. Responsibilities in this role included being the discovery coordinator for the Company's rate cases, line extension policy tariffs, as well as miscellaneous regulatory issues.

In November 2009, I was promoted to my current role.

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

A. In addition to discussing the Company's Forecast Revenue Load Adjustment, my testimony in this proceeding will cover the spread of the proposed annual margin/revenue increase among the Company's natural gas service schedules as well as the application of the increase to the rates within each of the schedules. The results of the Long-run Incremental Cost study ("LRIC") sponsored by Company witness Mr. Miller was used as a guide to spread the proposed margin/revenue increase by service schedule.

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

A. Yes. I am sponsoring Exhibit Nos. 901, 902 and 903, which were prepared under my direction.

Q. Would you please explain what is contained in Exhibit No. 901 and 902?

A. Yes. Exhibit No. 901 contains the present natural gas rates and schedules which are on file with the Commission as a part of our present tariff, PUC OR. No. 5. Exhibit No. 902 contains the proposed natural gas rates and schedules which reflect the proposed annual revenue increase of $9,481,000.

Q. What is contained in Exhibit No. 903?

A. Exhibit No. 903 contains information regarding the proposed rate spread and rate design of the proposed annual revenue increase of $9,481,000. Page 1 shows customer usage information by service schedule for 2012, 2013[1], and forecasted for 2014 and 2015. Page 2 shows the application of the overall revenue/margin increase by service schedule and

[1] Usage for 2013 includes actual booked usage for January through June and forecast usage for July through December.

the cost of service results before and after application of the proposed increase. Page 3 shows the proposed revenue and percentage increase by service schedule. Page 4 shows the present 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.

II. REVENUE ADJUSTMENT AND CUSTOMER USAGE

Q. Would you please describe the Forecast Revenue Load Adjustment?

A. Yes. The Forecast Revenue Load Adjustment, included in this filing as Adjustment 2.01 in Company witness Ms. Andrews' Exhibit No. 601, represents the difference between the Company's restated historical test period revenue during 2012 and forecasted revenue for 2014. Actual revenue for 2012 was restated for adjustments 1.01 through 1.05 as discussed by Ms. Andrews. These adjustments include test year weather normalization and the elimination of adder schedules. Forecasted revenue for 2014 is based on projected customer usage and number of customers from the Company's most recent forecast applied to the present natural gas rates in effect.

The Forecast Revenue Load Adjustment also contains an adjustment for purchased gas costs, which represents the difference between actual recorded natural gas costs during 2012 and "pro forma" natural gas costs for 2014. Pro forma natural gas costs for 2014 were determined using forecasted 2014 customer usage applied to the natural gas costs reflected in present rates, as approved by the Commission in UG-225 (the Company's 2012 Purchased Gas Adjustment ("PGA") filing).

Q. You mentioned that projected customer usage for 2014 was taken from the Company's most recent forecast. Could you please explain?

A. Yes. The Company's financial forecast is updated periodically to include the most recent actual results and for significant changes in the assumptions included in the forecast. The most recent financial forecast update was in July 2013. That forecast included an updated natural gas load forecast of the number of customers and total therm usage for future periods starting in July 2013.

Q. How often is the natural gas load forecast updated?

A. Prior to July 2013, the natural gas load forecast was updated on an annual basis. As of July 2013, the natural gas load forecast will be updated semi-annually; one forecast in the 2nd Quarter and one in the 4th Quarter.

Q. In Docket UG-201, what was agreed to as it relates to the forecast used for the Forecast Revenue Load Adjustment?

A. The Company agreed that it would use the most recent forecast of customer counts and natural gas usage that is used for financial reporting purposes in its future general rate cases, Integrated Resource Plan, and PGA proceedings.

Q. Did the Company meet that requirement in this general rate case?

A. Yes, the Company used the most recent forecast of customer counts and natural gas usage that is used for financial reporting.

Q. Did the Company utilize projected usage from this forecast for all schedules/customer classes?

A. Yes, projected customer usage from the forecast was used for all schedules.

Q. How does projected 2014 customer usage compare to (weather-normalized) usage since the Company's last general filing?

A. Page 1 of Exhibit No. 903 shows actual and weather-normalized usage by rate schedule for 2012, the actual/forecasted usage for 2013, and the forecasted usage for 2014 used in this filing. As shown on lines 35 and 37, total throughput (sales and transportation volumes) is projected to increase by approximately 3.3% over the two year period. Approximately 60% of the projected load increase is from sales customers, with the other 40% coming from transportation customers.

Q. How does the 2014 usage for residential customers compare to 2012?

A. As shown in Exhibit No. 903, page 1 lines 1 and 3, total forecasted 2014 usage for residential customers is 4.6% higher than total (weather-corrected) residential usage in 2012. In evaluating residential monthly use per customer, forecasted 2014 use per customer is 3.5% higher than monthly use per customer (weather-corrected) in 2012.

Q. How does projected 2014 usage for commercial customers compare to 2012 usage for that customer classes?

A. As shown in Exhibit No. 903, page 1 lines 7 and 9, total forecasted 2014 usage for commercial customers is 3.7% higher than total (weather-corrected) commercial usage in 2012.

Q. What was the impact on the Company's net operating income and revenue requirement resulting from the forecasted increase in natural gas loads?

A. As Ms. Andrews describes in her direct testimony (Exhibit No. 600), the forecasted increase in loads in 2014 as compared to 2012 results in an increase to net operating income of approximately $0.7 million and a reduction to revenue requirement of approximately $1.2 million. The Forecast Revenue Load Adjustment is Adjustment 2.01 in Exhibit No. 701.

Q. Is the Company proposing any changes to the present allocation of natural gas costs by rate schedule used in its PGA filings?

A. No, it is not.

III. PROPOSED RATE DESIGN AND RATE SPREAD

Q. Would you please describe the Company's present rate schedules and the types of natural gas service offered under each?

A. Yes. Table 1 below shows the type of customer and the number of customers served as of December 31, 2012, under each of the Company's Oregon natural gas schedules:

Table 1 – Customers by Rate Schedule

Schedule	Type of Customer	No. of Customers
Residential Sch. 410	Residential	85,322
General Sch. 420	Commercial	11,168
Lge. General Sch. 424	Large Commercial & Industrial	76
Interruptible Sch. 440	Large Commercial & Industrial	36
Seasonal Sch. 444	Non-winter Use	8
Transportation Sch. 456	Large Industrial	37
Sp. Contract Sch. 447	Large Industrial Transportation	4

Q. How does the Company propose to spread the proposed base revenue increase of $9,481,000, or 9.5%, among its various service schedules?

A. The Company utilized the results of the Long-run Incremental Cost study ("LRIC") sponsored by Company witness Mr. Miller as a guide to spread the proposed margin/revenue increase by service schedule. The spread of the proposed increase for Schedules 410 and 440 generally results in the margin-to-cost ratios for those service schedules moving to 1.00 (unity). The Company chose to move Schedules 410 and 420 to unity as their present margin-to-cost ratio was close to unity at present rates. The spread of the proposed increase for the other schedules, Schedules 420, 424, 444, and 456, generally results in the margin-to-cost ratios for the various service schedules moving approximately 50% closer to 1.00 (unity). Table 2 below shows the margin-to-cost ratio under present rates and proposed rates.

Table 2 – Margin to Cost Ratios

Schedule	Margin to Cost at Present Rates	Margin to Cost at Proposed Rates
Residential Schedule 410	0.99	1.00
General Schedule 420	0.93	0.96
Large General Schedule 424	1.47	1.27
Interruptible Schedule 440	1.01	1.00
Seasonal Schedule 444	1.12	1.06
Transportation Schedule 456	1.58	1.34

This information is also shown in more detail on page 2 of Exhibit No. 903.

Q. Did the Company consider moving all rate schedules to unity (1.00)?

A. The Company analyzed the resulting margin revenue increase for each schedule had all rate schedules been moved to unity. Avista chose not to make the full movement to unity because, had the Company proposed to move all schedules to unity, some schedules would have received a rate decrease, and others would have received an even larger overall increase. Given the size of the overall requested increase, the Company believes that a movement towards, but not to, unity for Schedules 420, 424, 444 and 456 is appropriate.

Q. Using the Company's proposed rate spread, what is the proposed percentage increase in base revenue for each schedule?

A. Table 3 below shows the proposed percentage increase in base revenue (including natural gas costs) for each service schedule[2]:

Table 3 – Proposed Base Revenue Increase by Rate Schedule

Schedule	Increase in Present Revenue
Residential Schedule 410	10.4%
General Schedule 420	9.6%
Large General Schedule 424	1.0%
Interruptible Schedule 440	4.6%
Seasonal Schedule 444	3.0%
Transportation Schedule 456	3.7%

More detailed information related to the revenue increase by schedule is shown on Page 3 of Exhibit No. 903.

Q. Is the Company projecting a PGA rate increase or decrease for customers this fall?

A. The Company will file its annual PGA on or before August 31, 2013, and is projecting an overall rate decrease. That projected reduction would help offset the requested

[2] For Schedule 456, including an estimate of 50.0 cents per therm for the cost of natural gas and pipeline transportation, the proposed increase to Schedule 456 rates represents an average increase of 0.6% in those customers' total natural gas bill.

general increase. The ultimate level of PGA rate change is dependent upon the Company's October 2013 PGA Update filing[3].

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 4 of Exhibit No. 903?

A. Yes. Page 4 of Exhibit No. 903 shows the present rates for each of the various schedules, the proposed increases to those rates, and the resulting proposed rates.

Q. Please describe the proposed changes in the rates for Residential Schedule 410 that result in the overall base revenue increase of 10.4% for that Schedule.

A. As shown on Page 4 of Exhibit No. 903, the Company is proposing an increase in the present monthly customer charge of $2.00 per month, from $7.00 to $9.00. The present charge per therm would be increased by $0.09190 per therm, from $0.42980 to $0.52170 per therm[4].

Q. Why is the Company proposing to increase the basic charge for Schedule 410?

A. A significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. As shown in Company witness Mr. Miller's Exhibit No. 801, the costs associated with billing, meter reading, meters and services are $16.15 per month for Schedule

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[3] Pursuant to Docket UM-1286, Avista is required to file its initial PGA on or before August 31 of each year, and provide an update to that filing in the first two weeks of October.

[4] The current base rate for Schedule 410 is $0.42993. This base rate includes the revenue adjustment factor for LIRAP Schedule 493 ($0.00013). As discussed later in my testimony, the Company is proposing to move that revenue adjustment factor to Schedule 493 and out of base rates. This change was made in Adjustment 1.03 (Eliminate Adder Schedules).

410[5]. The Company believes that it is appropriate to recover a more reasonable level of these fixed customer costs through the basic charge.

Q. What is the change in the average bill for a residential customer as a result of these proposed changes?

A. Based on an average usage level of 48 therms per month, the average bill for a residential customer, which includes both base and adder schedules, would increase $6.17 per month, or 10.6%, from $58.00 to $64.17.

Q. Could you please describe the changes you propose to the rates of General Service Schedule 420?

A. Yes. As shown on Page 4 of Exhibit No. 903, the present rates for service under Schedule 420 consist of an $9.00 per month customer charge and a base volumetric rate of $0.34376 per therm. The Company is proposing an increase in the customer charge of $3.00 per month, from $9.00 to $12.00, and an increase of $0.08961 per therm in the usage charge. These changes result in an overall proposed increase of 9.6% in base revenue for the Schedule.

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 and who have a relatively high load-factor compared to other firm service customers. The Company is proposing an increase of $0.00737 per therm to the present usage rate under the Schedule and an increase of $5.00 per

[5] See Exhibit 801, Page 1 line 32.

month in the present monthly customer charge, from $50.00 to $55.00 per month, resulting in an overall increase of 1.0% in base revenue under the Schedule.

Seasonal Service Schedule 444 is for customers who use no natural gas during December, January and February. There are 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 an increase in the per therm charge under the Schedule of $0.02597 per therm, resulting in an overall increase of 3.0% in base revenue under the Schedule.

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 are not assigned firm pipeline transportation costs 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 $0.02209 per therm, resulting in the proposed base revenue increase of 4.6% for the Schedule. There is also an annual minimum charge under the Schedule associated with usage of 50,000 therms per year multiplied by the margin rate; correspondingly, the annual minimum margin rate is proposed to increase by $0.02209 per therm.

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 4 of Exhibit No. 903, the present rates under the Schedule consist of a monthly customer charge of $275.00 and a five-block rate structure with declining rates for higher usage. The Company is proposing an increase of $25.00 per month to $300.00 for the monthly customer charge, and a uniform percentage increase of approximately 3.4% to all rate blocks under the Schedule[6].

Q. Is the Company proposing any other changes to its natural gas service tariffs in this filing?

A. The Company is proposing two additional changes to its natural gas service tariffs in this filing. The first tariff change that the Company is requesting relates to tariff Schedule 493, “Residential Low Income Rate Assistance Program (LIRAP) – Oregon” (“LIRAP”). In the Company’s last general rate case, the funding associated with LIRAP was removed from base rates (Schedule 410) and is now administered as a stand-alone tariff (Schedule 493). However, the Company inadvertently failed to remove the Revenue Adjustment Factor for LIRAP from Schedule 410. The rate under Schedule 493 is currently set at $0.00438 per therm. However, it should have been set at $0.00451 per therm including the Revenue Adjustment Factor. The Company adjusted for this error in Adjustment 1.03

[6] For Schedule 456, including an estimate of 50.0 cents per therm for the cost of natural gas and pipeline transportation, the proposed increase to Schedule 456 rates represents an average increase of 0.6% in those customers’ total natural gas bill.

(Eliminate Adder Schedules), and has included in its filing a revised Schedule 493 in Exhibit No. 902[7].

Q. What is the second change that the Company is proposing in this filing?

A. As Company witness Mr. Harper described in his testimony, the Company is currently passing through to customers the net benefits associated with the Company's purchase of the Klamath Falls Lateral. This benefit is administered through Rate Schedule 498, and includes both the revenue requirement associated with the purchase ($450,039 annually), and the reduction in firm demand costs ($1,424,294 annually).

As a part of the Company's upcoming 2013 PGA filing, scheduled to be filed on or before August 31, 2013, the Company will propose to remove from Schedule 498 the cost savings associated with the reduction in firm demand costs and pass those savings through to customers, along with any other changes in commodity and demand, through Schedule 461, "Purchased Gas Cost Adjustment Provision". As a result, Schedule 498 will then only contain the incremental revenue requirement associated with the Klamath Falls Lateral.

As Company witness Ms. Andrews discusses in her testimony, the Company is seeking recovery of the Klamath Falls Lateral revenue requirement in base rates. To avoid double recovery of the revenue requirement, the Company is proposing to cancel Schedule 498 as a part of its compliance filing when base rates change in this general rate case.

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

A. Yes, it does.

[7] The total amount of this error is $763.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

PATRICK D. EHRBAR
Exhibit No. 901

Present Natural Gas Service Tariffs

AVISTA CORPORATION
dba Avista Utilities

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:	**$7.00**
Commodity Charge Per Therm:	
Base Rate	$0.42993
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)
Schedule 476 – Intervenor Funding	$0.00066
Schedule 478 – DSM Cost Recovery	$0.01588
Schedule 493 – Low Income Rate Assistance Program	$0.00438
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)
Total Billing Rate *	**$1.06245**

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month
Customer Charge:	**$9.00**
Commodity Charge Per Therm:	
Base Rate	$0.34376
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)
Schedule 478 – DSM Cost Recovery	$0.01588
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)
Total Billing Rate *	**$0.97124**

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	**$50.00**
Commodity Charge Per Therm:	
Base Rate	$0.14259
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)
Schedule 478 – DSM Cost Recovery	$0.01588
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)
Total Billing Rate *	**$0.77007**

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Commodity Charge Per Therm:	
Base Rate	$0.10462
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.37688
Schedule 462 – Gas Cost Rate Adjustment	($0.08134)
Schedule 476 – Intervenor Funding	$0.00006
Total Billing Rate *	**$0.40022**

Annual Minimum Charge:

Each Customer shall be subject to an Annual Minimum Charge if their gas usage during the prior year does not equal or exceed 50,000 therms. Such Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 10.462 cents per therm.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Commodity Charge Per Therm:	
Base Rate	$0.15877
OTHER CHARGES:	
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)
Schedule 478 – DSM Cost Recovery	$0.01588
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)
Total Billing Rate *	**$0.78625**

Minimum Charge:
$5,810.92 per season.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month
Customer Charge:	**$275.00**

Volumetric Charge Per Therm:

	Base Rate	Schedule 476	Billing Rate*
First 10,000	$0.15639	$0.00006	**$0.15645**
Next 20,000	$0.09412	$0.00006	**$0.09418**
Next 20,000	$0.07737	$0.00006	**$0.07743**
Next 200,000	$0.06056	$0.00006	**$0.06062**
All Additional	$0.03072	$0.00006	**$0.03078**

Minimum Charge:
The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

* The rates shown in this Rate Schedule may not always reflect actual billing rates. See the corresponding rate schedules for the actual rates.

(continued)

Kelly Norwood

SCHEDULE 493

RESIDENTIAL LOW INCOME RATE ASSISTANCE PROGRAM (LIRAP)-OREGON

PURPOSE:

The purpose of this schedule is to adjust rates in Schedule 410 – General Residential Natural Gas Service – Oregon, to generate funds to be used for bill payment assistance for Avista's qualifying low-income residential customers, in accordance with ORS 757.315.

APPLICABLE:

To all residential Customers in the State of Oregon where the Company has natural gas service available. This Residential Low Income Rate Assistance Program (LIRAP) Adjustment shall be applicable to all residential customers taking service under Schedule 410. This Rate Adjustment, set below is approximately 0.5% of retail rates.

MONTHLY RATE:

The Commodity Charge per therm of the individual rate schedules are to be adjusted by the following amounts:

Rate Schedule	**Rate**
Schedule 410	$0.00438 per Therm

SPECIAL CONDITIONS:

1. Each month, the Company will bill and collect low-income bill payment assistance funds from all Residential Customers. By the 10th of the month following the billing month, using the Company's internal cashless voucher system, the Company will determine and send the monthly voucher amount showing the Program Payment funds available to each participating Community Action Agency. By the 20th of the month following the billing month, the Company will remit payment to each Agency for allowed administrative and program delivery costs. Each agency will process client intake, authorize payments, and provide the Company with a client voucher list. Based on this client voucher list, the Company will transfer the authorized payments to the individual customer's utility account.

(continued)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

PATRICK D. EHRBAR
Exhibit No. 902

Proposed Natural Gas Service Tariffs

SCHEDULE 410

GENERAL RESIDENTIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to residential natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	**$9.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.52170	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831	
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)	
Schedule 476 – Intervenor Funding	$0.00066	
Schedule 478 – DSM Cost Recovery	$0.01588	
Schedule 493 – Low Income Rate Assistance Program	$0.00451	(I)
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)	
Total Billing Rate *	**$1.15435**	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 420
GENERAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to commercial and small industrial natural gas service for all purposes.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month	
Customer Charge:	**$12.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.43337	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831	
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)	
Schedule 478 – DSM Cost Recovery	$0.01588	
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)	
Total Billing Rate *	**$1.06085**	(I)

Minimum Charge:

The Customer Charge constitutes the Minimum Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 424

LARGE GENERAL AND INDUSTRIAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable to large commercial and industrial use customers where at least 75% of the natural gas requirements are for uses other than space heating and where adequate capacity exists in the Company's system. Customers served under this schedule must use a minimum of 29,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Customer Charge:	**$55.00**	(I)
Commodity Charge Per Therm:		
Base Rate	$0.14996	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831	
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)	
Schedule 478 – DSM Cost Recovery	$0.01588	
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)	
Total Billing Rate *	**$0.77744**	(I)

Minimum Charge:

The minimum monthly charge shall consist of the Monthly Customer Charge.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 440

INTERRUPTIBLE NATURAL GAS SERVICE FOR LARGE COMMERCIAL AND INDUSTRIAL - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must use a minimum of 50,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:

	Per Meter Per Month	
Commodity Charge Per Therm:		
Base Rate	$0.12671	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.37688	
Schedule 462 – Gas Cost Rate Adjustment	($0.08134)	
Schedule 476 – Intervenor Funding	$0.00006	
Total Billing Rate *	**$0.42231**	(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 Annual Minimum Charge shall be determined by subtracting their actual usage for a twelve-month period from 50,000 therms multiplied by 12.671 cents per therm. (I)

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 444

SEASONAL NATURAL GAS SERVICE - OREGON

APPLICABILITY:

Applicable for natural gas service to customers whose entire natural gas requirements for any calendar year are supplied during the period from and after March 1, and continuing through November 30, of each year.

Service under this schedule is not available to any "essential agricultural user" or "high priority user" (as defined in section 281.203(a), Title 18, Code of Federal Regulations), who has requested protection from curtailment, as contemplated by Section 401 of the NGPA (Public Law 95-261). An "essential agricultural" or "high-priority" user receiving service under this schedule can obtain protection from curtailment by requesting transfer to the appropriate firm rate schedule of the Company.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month	
Commodity Charge Per Therm:		
Base Rate	$0.18474	(I)
OTHER CHARGES:		
Schedule 461 – Purchased Gas Cost Adjustment	$0.70831	
Schedule 462 – Gas Cost Rate Adjustment	($0.08595)	
Schedule 478 – DSM Cost Recovery	$0.01588	
Schedule 498 – Klamath Falls Lateral Capital Project	($0.01076)	
Total Billing Rate *	**$0.81222**	(I)

Minimum Charge:
$5,810.92 per season.

* The rates shown in this Rate Schedule as Other Charges may not always reflect actual billing rates. See the corresponding rate schedules under Other Charges for the actual rates.

(continued)

SCHEDULE 456

INTERRUPTIBLE TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE - OREGON

APPLICABILITY:

Applicable, subject to interruptions in capacity and supply, for the transportation of customer-owned natural gas for large commercial and industrial use where capacity in excess of the existing requirements of firm sales and transportation customers exists in the Company's system. Customers served under this schedule must transport over the Company's system a minimum of 225,000 therms annually.

TERRITORY:

This schedule is applicable to the entire territory in the State of Oregon served by the Company.

THERM:

The word "therm" means one hundred thousand British Thermal Units (100,000 B.T.U.)

RATES:	Per Meter Per Month	
Customer Charge:	**$300.00**	(I)

Volumetric Charge Per Therm:

	Base Rate	Schedule 476	Billing Rate*	
First 10,000	$0.16174	$0.00006	**$0.16180**	(I)
Next 20,000	$0.09734	$0.00006	**$0.09740**	|
Next 20,000	$0.08002	$0.00006	**$0.08008**	|
Next 200,000	$0.06263	$0.00006	**$0.06269**	|
All Additional	$0.03177	$0.00006	**$0.03183**	(I)

Minimum Charge:

The minimum monthly charge shall be $1,354.30 per month, accumulative annually.

* The rates shown in this Rate Schedule may not always reflect actual billing rates. See the corresponding rate schedules for the actual rates.

(continued)

SCHEDULE 493

RESIDENTIAL LOW INCOME RATE ASSISTANCE PROGRAM (LIRAP)-OREGON

PURPOSE:

The purpose of this schedule is to adjust rates in Schedule 410 – General Residential Natural Gas Service – Oregon, to generate funds to be used for bill payment assistance for Avista's qualifying low-income residential customers, in accordance with ORS 757.315.

APPLICABLE:

To all residential Customers in the State of Oregon where the Company has natural gas service available. This Residential Low Income Rate Assistance Program (LIRAP) Adjustment shall be applicable to all residential customers taking service under Schedule 410. This Rate Adjustment, set below is approximately 0.5% of retail rates.

MONTHLY RATE:

With Gross Revenue Factor:	$.00451 per therm	(C)
Without Gross Revenue Factor:	$.00438 per therm	(C)

SPECIAL CONDITIONS:

1. Each month, the Company will bill and collect low-income bill payment assistance funds from all Residential Customers. By the 10th of the month following the billing month, using the Company's internal cashless voucher system, the Company will determine and send the monthly voucher amount showing the Program Payment funds available to each participating Community Action Agency. By the 20th of the month following the billing month, the Company will remit payment to each Agency for allowed administrative and program delivery costs. Each agency will process client intake, authorize payments, and provide the Company with a client voucher list. Based on this client voucher list, the Company will transfer the authorized payments to the individual customer's utility account.

(continued)

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-246

PATRICK D. EHRBAR
Exhibit No. 903

Rate Spread & Rate Design

Avista Utilities
State of Oregon
Comparison of Natural Gas Usage
2012 Weather-Normalized, 2013 Actual & Forecast *, and 2014-2015 Forecast

Line No.		Actual Usage	Weather Adj.	Normalized Usage	Avg. Customers	Annual Use/ Customer	Monthly Use/ Customer
	Residential Sch 410						
1	2012	47,041,367	(288,897)	46,752,470	84,638	552.4	46.0
2	2013	46,593,333	5,800	46,599,133	85,009	548.2	45.7
3	2014	48,912,477		48,912,477	85,557	571.7	47.6
4	2015	49,231,963		49,231,963	86,190	571.2	47.6
5							
6	**Commercial Sch 420**						
7	2012	25,257,200	(138,795)	25,118,405	11,119	2,259	188
8	2013	25,296,630	23,338	25,319,968	11,172	2,266	189
9	2014	26,046,807		26,046,807	11,231	2,319	193
10	2015	26,166,977		26,166,977	11,307	2,314	193
11							
12							
13	**Large Sales Schs. 424, 440 & 444**						
14	2012	7,682,086		7,682,086	117	65,659	5,472
15	2013	6,991,182		6,991,182	117	59,584	4,965
16	2014	6,873,520		6,873,520	118	58,250	4,854
17	2015	6,952,885		6,952,885	120	57,941	4,828
18							
19							
20	**Total Sales Volumes**						
21	2012			79,552,961	95,874		
22	2013			78,910,283	96,299		
23	2014			81,832,804	96,906		
24	2015			82,351,825	97,617		
25							
26							
27	**Transport Schs. 447 & 456**						
28	2012	36,219,432		36,219,432	40	905,486	75,457
29	2013	36,728,323		36,728,323	40	910,620	75,885
30	2014	37,724,799		37,724,799	40	943,120	78,593
31	2015	39,433,624		39,433,624	40	985,841	82,153
32							
33							
34	**Total Throughput**						
35	2012			115,772,393			
36	2013			115,638,606			
37	2014			119,557,603			
38	2015			121,785,449			

* The 2013 numbers include January through June actual booked usage and July through December forecasted usage.

Avista Utilities
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2014

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
1	CURRENT REVENUE	$ 99,358,000	62,855,000	28,616,000	3,535,000	1,221,000	207,000	279,000	2,645,000
2	COST OF GAS	$ 57,140,000	34,655,000	18,455,000	2,904,000	957,000	169,000	$ -	$ -
3	CURRENT MARGIN	$ 42,218,000	$ 28,200,000	$ 10,161,000	$ 631,000	$ 264,000	$ 38,000	$ 279,000	$ 2,645,000
4	% of Current Margin excl Sch 447	100.00%	67.24%	24.23%	1.50%	0.63%	0.09%		6.31%
5	Total Revenue Requirement	$ 9,481,000							
6	Revenue Requirement as a Percent of Margin Revenue	22.46%							
7	Percentage Applied to Overall Margin Increase		103.40%	120.00%	25.00%	95.00%	70.00%		16.31%
8	Increase as a Percent of Total Current Margin		23.22%	26.95%	5.61%	21.33%	15.72%		3.66%
9	**PROPOSED MARGIN REVENUE INCREASE**	**$ 9,481,000**	**$ 6,548,134**	**$ 2,738,257**	**$ 35,426**	**$ 56,323**	**$ 5,974**		**$ 96,887**
10	**Percentage Revenue Increase**	**9.54%**	**10.42%**	**9.57%**	**1.00%**	**4.61%**	**2.89%**		**3.66%**
	Cost of Service								
11	Proposed Margin	$ 51,699,000	$ 34,748,134	$ 12,899,257	$ 666,426	$ 320,323	$ 43,974	$ 279,000	$ 2,741,887
12	LRIDC Based Target Margin (Line 27 of Miller Exhibit 801 Page 1 of 3)	**$ 51,699,000**	**34,919,238**	**13,446,477**	**524,091**	**320,714**	**41,599**	**393,995**	**2,052,886**
13	**Relative Margin to Cost at Present Rates (Line 29A of Miller Exhibit 801 Page 1 of 3)**	**1.00**	**0.99**	**0.93**	**1.47**	**1.01**	**1.12**	**0.87**	**1.58**
14	**Relative Margin to Cost at Proposed Rates**	**1.00**	**1.00**	**0.96**	**1.27**	**1.00**	**1.06**		**1.34**

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2014
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Base Revenue Under Present Rates	GRC Increase/ (Decrease)	Base Revenue Under Proposed Rates	Therms (000s)	**Base Revenue Percentage Increase**	Billed Revenue Under Present Rates	GRC Increase/ (Decrease)	Klamath Falls Lateral Reduction Schedule 498	Billed Revenue Under Proposed Rates	**Billed Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential	410	$62,855	$6,548	$69,403	48,912	**10.4%**	$59,148	$6,548	($244)	$65,452	**10.7%**
2	General Service	420	28,616	2,738	31,354	26,047	**9.6%**	26,511	$2,738	($130)	$29,119	**9.8%**
3	Large General Service	424	3,535	36	3,571	4,099	**1.0%**	3,204	$36	($20)	$3,220	**0.5%**
4	Interruptible Service	440	1,221	56	1,277	2,536	**4.6%**	1,015	$56		$1,071	**5.5%**
5	Seasonal Service	444	207	6	213	238	**3.0%**	188	$6	($1)	$193	**2.7%**
6	Transportation Service	456	2,645	97	2,742	30,374	**3.7%**	2,646	$97		$2,743	**3.7%**
7	Special Contract	447	279	0	279	7,351	**0.0%**	279	$0		$279	**0.0%**
8	Total		$99,358	$9,481	$108,839	119,558	**9.5%**	$92,991	$9,481	($395)	$102,077	**9.8%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Base Rates (Including Gas Costs)	Proposed Schedule 493 Adjustment	Schedule 461 PGA Gas Costs	Present Base Rates	Change	Proposed Base Rates
Residential Service Schedule 410					
$7.00 Customer Charge			$7.00 Customer Charge	$2.00/month	$9.00 Customer Charge
All Therms - $1.13824/Therm	All Therms - -$0.00013/Therm	All Therms - -$0.70831/Therm	All Therms - $0.42980/Therm	$0.09190/therm	All Therms - $0.52170/Therm
General Service Schedule 420					
$9.00 Customer Charge			$9.00 Customer Charge	$3.00/month	$12.00 Customer Charge
All Therms - $1.05207/Therm		All Therms - -$0.70831/Therm	All Therms - $0.34376/Therm	$0.08961/therm	All Therms - $0.43337/Therm
Large General Service Schedule 424					
$50.00 Customer Charge			$50.00 Customer Charge	$5.00/month	$55.00 Customer Charge
All Therms - $0.85090/Therm		All Therms - -$0.70831/Therm	All Therms - $0.14259/Therm	$0.00737/therm	All Therms - $0.14996/Therm
Interruptible Service Schedule 440					
All Therms - $0.48150/Therm		All Therms - -$0.37688/Therm	All Therms - $0.10462/Therm	$0.02209/therm	All Therms - $0.12671/Therm
Seasonal Service Schedule 444					
All Therms - $0.86708/Therm		All Therms - -$0.70831/Therm	All Therms - $0.15877/Therm	$0.02597/therm	All Therms - $0.18474/Therm
Transportation Service Schedule 456					
$275.00 Customer Charge			$275.00 Customer Charge	$25.00/month	$300.00 Customer Charge
1st 10,000 Therms - $0.15639/Therm			1st 10,000 Therms - $0.15639/Therm	$0.00535/therm	1st 10,000 Therms - $0.16174/Therm
Next 20,000 Therms - $0.09412/Therm			Next 20,000 Therms - $0.09412/Therm	$0.00322/therm	Next 20,000 Therms - $0.09734/Therm
Next 20,000 Therms - $0.07737/Therm			Next 20,000 Therms - $0.07737/Therm	$0.00265/therm	Next 20,000 Therms - $0.08002/Therm
Next 200,000 Therms - $0.06056/Therm			Next 200,000 Therms - $0.06056/Therm	$0.00207/therm	Next 200,000 Therms - $0.06263/Therm
Over 250,000 Therms - $0.03072/Therm			Over 250,000 Therms - $0.03072/Therm	$0.00105/therm	Over 250,000 Therms - $0.03177/Therm