Oregon
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October 16, 2015

Via Electronic Filing and Huddle

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
SALEM OR 97302-1088

**RE: Docket No. UG 288 – In the Matter of
AVISTA CORPORATION, dba AVISTA UTILITIES,
Request for a General Rate Revision.**

Enclosed for filing is Staff Opening Testimony in UG 288, together with a Certificate of Service and UG 288 Service List.

Exhibits 207, 303, 305, 500, 502, 503, 605, 800, 803, 1100, and 1103 are confidential.

Per Parties approval this voluminous filing both confidential and non-confidential will be uploaded to Huddle by close of business today. They will be available to the parties that were assigned confidential access to the Huddle information.

/s /Mark Brown
Executive Assistant
(503) 378-8287
Email: mark.brown@state.or.us

CASE: UG 288
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Overall Rev Req, Uncollectibles, Working Cash Rev Sensitive state tax, State Tax, Escalation

Opening Testimony

October 16, 2015

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

A. My name is Marianne Gardner. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. I introduce Staff-sponsored adjustments and issues regarding Avista's (AVA's or Company's) filing in this docket, identified as UG 288. As such, I verify AVA's proposed revenue requirement utilizing Staff's revenue requirement model. This model is also used to calculate Staff's modified revenue requirement incorporating Staff's proposed adjustments to AVA's revenue requirement. Additionally, I provide background regarding specific issues I reviewed, my analysis, and my recommendations.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following exhibits.

Exhibit 102	DR Nos. 180 and 214 - SIT calculation
Exhibit 103	DR No. 135 – Bonus depreciation
Exhibit 104	Renewal of bonus depreciation
Exhibit 105	SIT calculation – Staff proposal

Q. Will other Staff submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to UG 288 is submitting separate testimony. In Part 1 of my testimony, I will introduce the Staff witnesses, their respective assignments, and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing.

Q. Are Staff's recommendations definitive of their final position regarding the Company's filed case?

A. No. Staff reserves the right to revise its recommendations on these issues as the need arises due to additional discovery or based upon Staff's review of the intervening parties' testimony in this docket.

Q. How is your testimony organized?

A. My testimony is organized as follows:

PART 1, REVENUE REQUIREMENT

Q. Please provide a list of the rate case topics that Staff reviewed, introduce the responsible Staff, and identify those issues for which Staff recommends a revenue requirement adjustment.

A. I have provided a listing in Table A.

Table A

Staff Issue Summary
Avista Utilities
UG 288 – General Rate Case
2016 Test Year
($000)

				Company Filed General Rate Required Change to Revenue Requirement				**$8,557**
					Staff Proposed Adjustments			
Exhibit No.	**Testimony Issue No.**	**Staff's Rev. Req. Model Adj. No.**	**Staff Witness**	**Description**	**Rev.**	**Exp.**	**Rate Base**	**Rev. Req. Effect**
100	4	S-4.1	Marianne Gardner	Revenue Sensitive: State Effective Tax Rate				**(41)**
100	1	S-1	Marianne Gardner	Uncollectibles		**(7)**		**(7)**
100	2	S-2	Marianne Gardner	Working Cash			**(1,090)**	**(116)**
100	3	S-3	Marianne Gardner	Interest Synchronization				**7**
100	4	S-4.2	Marianne Gardner	State Tax		**(1,213)**		**(1,353)**
100	5	I-8	Marianne Gardner	Escalation				
200	1	S-0	Matt Muldoon	Cost of Capital				**(1,552)**
300	1	S-6	Judy Johnson	Information Technology			**(1,243)**	**(132)**
300	2	S-9	Judy Johnson	Distribution O&M		**(550)**		**(568)**
400	1 & 2	S-17	Ming Peng	Depreciation		**(281)**	**(173)**	**(308)**
500	1	S-7.1	Linnea Wittekind	D&O		**(577)**		**(596)**

500	2	S-7.2	Linnea Wittekind	Various A&G		**(30)**		**(31)**
600	1	S-8	Mitch Moore	Plant			**(30,003)**	**(3,194)**
700	3	S-10	Erik Colville	Other Gas Supply		**(80)**		**(83)**
700	1	I-1	Erik Colville	Gas Inventory				
700	5	I-2	Erik Colville	IRP				
700	2	I-3	Erik Colville	Storage Operating Expense				
700	4	I-8	Erik Colville	Purchased Gas Expense				
800	2	S-11	Brian Bahr	Medical Benefits		**(175)**		**(181)**
800	4	S-12	Brian Bahr	Wages & Salaries		**(350)**	**(283)**	**(392)**
800	3	S-13	Brian Bahr	Property Taxes		**(67)**		**(69)**
800	1	S-14	Brian Bahr	Pension Adjustment		**(435)**	**(5,655)**	**(1,051)**
900	1	S-15	Max St. Brown	Other Revenues - Misc. Revenue	**34**			**(34)**
900	2	I-9	Max St. Brown	Load Forecasting (Commercial & Industrial)				
1000	1	S-16	Suparna Bhattacharya	Load Forecasting (Residential,	**867**			**925**
1000	2	I-5	Suparna Bhattacharya	Decoupling and Public Purpose Charge				
1100	1	S-17	Jorge Ordonez	Cost Allocations		**(9)**		**(9)**
1200	1	I-6	Lisa Gorsuch	Advertising				
1300	1	I-7	George R. Compton	LRIC, Rate Spread and Rate Design				
Total Staff Proposed Adjustments (Base Rates)								**(8,784)**
Staff Calculated Revenue Requirements Change (Base Rates)								**(227)**

Part 2, Specific Issues

Q. What areas of Avista's filing are you primarily responsible for reviewing?

A. I reviewed the portions of the filing related to uncollectible expense, state income tax (SIT) and federal income tax (FIT), accumulated deferred income taxes (ADIT), and working capital allowance. In order to gain additional insight, I reviewed the Company's responses to related Standard Data Requests (SDRs), issued approximately 25 data requests, and reviewed the Company's responses to my data requests and multiple data requests in these areas submitted by other Staff and the intervening parties.

Q. For each issue, please provide a summary of the Commission's historical treatment, the Company's filed proposal, Staff's analysis of the issue, and Staff's recommendation.

A. Below is a summary of each issue. I have labeled each to correspond to Table A.

Issue 1: Uncollectibles

It is a long-standing policy of the Commission Staff to apply a three-year average methodology to determine the test year uncollectible expense for a utility's revenue requirement.[1] However, Commission Staff also examines other evidence to determine whether this approach results in a reasonable forecasted test year result.

[1] *See e.g.*, Order Nos. 14-015 and 09-422 (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on 3-year average); *but see* Order No. 05-871 (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on 4-year average).

In this case, the Company includes $347,000 as uncollectible expense in its proposed 2016 Average of Monthly Averages (AMA) test year.[2] According to the electronic workpapers accompanying the Company's initial filing, the Company calculated an uncollectible rate based on a three-year average (2012-2014) of net write offs to general revenues, (total business revenues and total transportation revenues) of 0.54956 percent.[3] The Company utilized this rate in its net income to gross revenue conversion factor[4]. However, the inferred rate for the Company's proposed 2016 test year is 0.56245 percent, (proposed 2016 test year uncollectible expense of $347,000 divided by proposed 2016 test year combined business revenues and transportation revenues of $61,781,000).

After analyzing and trending the various collections-related data for the years 2010 through 2014 provided by the Company in responses to Staff data requests DR Nos. 170-174 and 210-211, I conclude that the uncollectible rate of 0.54956 percent reasonably forecasts the level of uncollectible expense for the 2016 test year. Therefore, I agree with the Company's inclusion of 0.54956 percent in its proposed 2016 test year gross revenue conversion factors.

However, as demonstrated in the paragraph above, the Company's proposed 2016 test year uncollectible expense of $347,000 is not 0.54956 percent of the general business and transportation revenues. Therefore, I recommend that 0.54956 percent uncollectible conversion rate be applied to the proposed 2016

[2] Avista/501, Smith/1 at 12/Column c.
[3] Workpapers\UG-_Smith WP (Avista) (May 2015)\Smith Native Format Workpapers\3.00 G-UE\2015 Uncollectible Accounts.xlsx.
[4] Avista/501, Smith/3 at 3.

test year general business revenues and transportation revenues. I will multiply Staff's recommended total revenue requirement by the 0.54956 percent for the proper level of uncollectible expense.

Issue 2: Working Cash

Commission Staff's long-standing policy has been to exclude working capital from rate base for gas utilities. In Avista UG 201, UG 246 and UG 284, Staff's position has been that the natural gas and electric industries are sufficiently different, which compromises the accuracy of the Working Capital allocation to Oregon. In Avista's two most recent rate cases, UG 246 and UG 284, Staff stipulated to allowing Avista to include rate base materials and supplies in inventory costs. The Commission adopted those stipulations.

Avista proposes to increase rate base by $1,090,000 for working capital in adjustment 2.08.[5] Referring to Ms. Smith's testimony, Avista/500, Smith/21 at lines 10-20, Ms. Smith states "Column (2.08), entitled Working Capital, increases total rate base for the Company's working capital adjustment." She also notes, in relevant part, "Working capital represents investor supplied funds that are properly included in the Company's rate base for ratemaking purposes." "... The Company has calculated its working capital in this proceeding using the Investor Supplied Working Capital (ISWC) method."

I recommend disallowing Avista's $1,090,000 addition to rate base for working capital based on the ISWC method. This recommendation conforms to Staff's existing policy.

[5] Avista/501, Smith/8 at line 251.

Issue 3: Interest Synchronization

According to long-standing Commission policy, for ratemaking purposes, Staff routinely coordinates or "synchronizes" interest expense to reflect changes to the regulated utility's cost of capital as initially filed in a general rate case. This is consistent with the treatment in Avista's last general rate case, UG 284. This adjustment is dependent on Staff witness Matt Muldoon's proposed modification to the Company's weighted cost of debt in his adjustment, S-0, Cost of Capital. Once parties agree on the weighted cost of debt, or the Commission determines what this is, then interest must be coordinated or synchronized to determine the related adjustment for the income tax calculation.[6]

Issue 4: State Income Taxes (SIT), SIT revenue sensitive rate, Federal Income Taxes (FIT), Accumulated Deferred Income Taxes (ADIT)

Consistent with Internal Revenue Code Section (IRC Sec.) 168(f)(2) and 168(i)(9), normalization rules for public utilities, the Commission requires that utilities normalize federal income taxes for revenue requirement purposes. Additionally, ORS 757.269 mandates the Commission balance the interests of utility customers and utility investors in setting rates that include income taxes. ORS 757.269 (1) states,

> "[s]ubject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just

[6] For a more complete explanation, *see* Staff/700, Gardner/9 at lines 1-20 (Docket No. UE 294).

> and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operation of the utility." According to subsection (3),

> *"During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes a part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon: (a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation; (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or (c) Any other considerations the commission deems relevant to protect the public interest."*

Avista has included for FIT and SIT in their 2016 test year, $6,594,000 and $1,877,000 respectively, for a total of $8,472, 000.[7] According to Avista's response to Staff DR No. 212[8], Avista does not normalize state income tax expense. Avista estimated the 2016 AMA Test Year SIT using the

[7] Avista/501, Smith/1 at lines 26-30/column e.
[8] Staff/102, Gardner/1.

apportionment method. Avista used this same methodology in UG 284.[9] For the incremental revenue requirement and for the net-to-gross factor, Avista used an 8 percent SIT rate.[10] Referring to Avista/500, Smith/30 Ms. Smith states, "The 8.0% tax rate was determined by "grossing up" the 0.614% apportionment rate for system taxable net income by Oregon's share of system revenues. Oregon's revenues from its natural gas operations represent approximately 7.68% of total revenues. Therefore, 0.614% divided by 7.68% equals 8.0%, which is the Oregon apportionment tax rate used in this filing."

Q. Does Avista's proposed SIT, FIT and ADIT included in the 2016 test year conform to Commission policy?

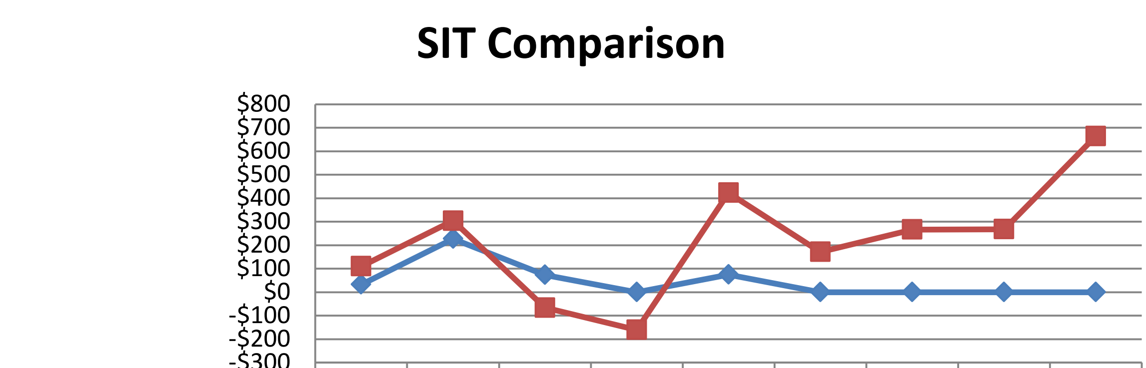
A. Avista's normalization of FIT and the inclusion of ADFIT in rate base comply with both IRC regulation and Commission policy. However, while not violating IRC normalization rules, from my viewpoint, Avista's application of the flow-through method for Oregon state income taxes appears to include an over-estimation of SIT in the Company's Results of Operations report (ROO) compared to the Company's Oregon excise tax return. Staff's concern is that the tax benefits related to bonus depreciation and business energy tax credits (BETCs) are not flowing through to ratepayers, that the 2016 SIT expense may be excessive, and there is no offsetting effect of ADIT in rate base to counter balance the overstatement.

Q. Would you please provide an illustration that supports Staff assertion that SIT may have been overstated.

[9] Avista/500, Smith/28 at lines 10-14.
[10] Avista/500, Smith/29 at lines 9-23 and 30 at lines 1-19.

A. Yes. Table B below compares the Oregon gas jurisdiction's share of Oregon SIT from the Company's filed Oregon Form 20 versus the Company's filed Oregon Results of Operations Report (ROO) for the years 2005 through 2013, inclusive. Avista provided this information in Staff_DR_214_Attachment A.xlsx in response to Staff's DR No. 214. The Company's narrative response has been included in Exhibit 102 and its excel attachment A is included in Staff's non-confidential workpapers, UG 288 Exhibit 102 Gardner DR 214.xls. As Table B displays, the Company over-forecasted its ROO SIT expense from 2009 through 2013, inclusive. The 2013 ROO SIT jumps to $664,600 versus zero dollars for the 2013 tax return. The forecasted 2016 test year SIT doubles to $1,213,000.

Table B



	2005	2006	2007	2008	2009	2010	2011	2012	2013
OR Form 20 (OR Gas allocated)	32.8	227.4	73.2	0.1	75	0	0	0	0
OR ROO	110.2	303.7	-66.2	-160.9	423.3	171.4	266.8	267.6	664.6

Q. What appear to be the main drivers for the Company's over-estimation of the ROO SIT for the years 2009 through 2013?

A. Based on my review of the Company's response to DR No. 214, the main drivers have been the availability of Oregon Business Energy Tax Credits (BETCs) and bonus depreciation. As the Company notes in its response to Staff DR No. 135,[11] Congress reenacted bonus depreciation for 2008 and then has continually extended bonus depreciation for each tax year through 2014, inclusive. The Company was able to use bonus depreciation to lower taxable income and BETCs to offset Oregon Form 20 SIT.

Q. What is the Company's position regarding the availability of bonus depreciation and BETCs for the 2015 forecast and 2016 test year?

A. According to Avista witness Smith's testimony,[12] the Company predicted bonus depreciation would not be available for 2015 or 2016. As a result, the Company forecasted virtually all of its BETCs would be consumed against its projected 2015 SIT expense, leaving only $11,558 of BETCs available for 2016.[13] Without BETCs and bonus depreciation for offset, Avista forecast is $1,213,787 of SIT expense for their Restated 2016 AMA Test Year.

Q. Are there any indications that Congress may extend bonus depreciation for the 2015 and 2016 tax years?

A. Yes. According to Baker Tilly, bonus depreciation has been available from 2008 through 2014.[14] In July 2015, the Senate Finance Committee overwhelming voted to extend bonus depreciation for 2015 and 2016.[15] On

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[11] Staff/103, Gardner/1
[12] Avista/500, Smith/ 28 at lines 19-20 and 29 at lines 1-5.
[13] Staff/102, Gardner/3
[14] Staff/104, Gardner/1
[15] Staff/104, Gardner/2

September 17, 2012, the House Ways and Means Committee approved legislation to permanently extend bonus depreciation.[16] While any tax extender bill still has to pass the full Senate, the full House, and then be approved by the President before enacted into law, there appears to be strong legislative support to continue bonus depreciation through 2016 and perhaps permanently.

Q. Based on this legislative news, does Staff propose an alternative estimate of state taxes for the 2016 test year?

A. Yes. I have prepared an alternative calculation which I have included in my Exhibit 105. In my calculation, I assume the same level of bonus depreciation as Avista has included for 2014 for the 2015 forecast and the 2016 test year. As a result of including bonus depreciation for 2015 and 2016, there are sufficient BETCs available to credit against Oregon Form 20 SIT tax. Consequently, I conclude that Avista will owe no Oregon SIT for either year and recommend the full amount, $1,213,787, of SIT expense be removed from the Company's Restated 2016 AMA Test Year.

Q. Does Staff agree with the Company's proposed SIT rate of 8 percent used in Avista's 2016 test year conversion factor calculation?

A. No. The Company's 8 percent rate is higher than the Oregon Form 20 SIT rate. According to the instructions to 2014 Oregon Form 20 line 16, "Calculated excise tax," Oregon taxable income greater than $1 million is multiplied by 7.6% then $66,000 is added for the tax on the first $1 million.

[16] Staff/104, Gardner/5

Using this formula, I propose a SIT revenue sensitive factor of 7.2812 percent based on my calculation of 2016 Oregon SIT before BETCs (OR SIT/OR taxable income = $194.3K/2,688.6K = 7.2812 percent)[17]. I recommend 7.2812 percent be used as the SIT factor in the net-to-gross factor (conversion factor) for the incremental Revenue Requirement calculation.

<u>Issue 5: Escalation</u>

It is Staff policy to use the Consumer Price Index – All Urban Consumers as published by the State of Oregon Office of Economic Analysis for year over year escalation. The most recent release was August 26, 2015. According to Appendix A of this report, the percentage change for 2014 to 2015, and 2015 to 2016, is 0.2 percent and 1.8 percent, respectively. Therefore, the escalator for 2014 actuals to the 2016 test year end would be approximately 1.2 percent.

According to the Company's supporting workpapers for Adjustment 2.00 G-FE that accompanied the Company's original filing, Avista utilized the December CPI – All Urban percentage change between 2013 and 2014 of 0.8 percent to escalate 2014 non-labor costs for both 2015 and 2016. The 2016 test year non-labor expenses were escalated approximately 1.16 percent over 2014. (Ms. Smith states in her testimony that the CPI change was .08 percent.[18] However, it appears that was a typographical error.)

Based on my review, I do not recommend any adjustment to the Company's escalation adjustment. This does not preclude other Staff recommending adjustments to specific expense accounts based on their individual analysis.

[17] Staff/105, Gardner/1 at cell S30
[18] Avista/500, Smith/12 at lines 15-20.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	Marianne Gardner
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Master of Business Administration Oregon State University, Corvallis, Oregon Bachelor of Science in Accounting Montana State University, Bozeman, Montana CPA, Oregon

EXPERIENCE:

I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UG 284, UE 294, and UG 287.

I have approximately 23 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;
- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,
- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UG 288
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/04/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 212	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

REQUEST:

Please explain whether the Company normalized Oregon state income tax expense and included the related Oregon deferred state income tax in rate base for the 2016 test year. If not, please explain why not. In the response, please cite any supporting testimony or data responses.

RESPONSE:

The Company does not normalized Oregon state income tax expense and therefore, the Company included no related Oregon deferred state income tax in rate base for the 2016 test year.

This information was provided in response to Staff_DR_138:

> "First, the Company does not record deferred state income taxes. The Company uses the flow-through method for Oregon state income taxes."

Avista did not address this issue in its testimony in the current case, since the accounting for state income taxes has not changed for several years. During 2010 and 2011, the Company brought to the attention of Oregon PUC Staff that even though for a short period of time, the Company had recorded deferred state income taxes on its books, the Company had not included deferred state income taxes in any of its rate cases. As part of the settlement in UG-171(4), which was the annual tax filing under ORS 757.268 (i.e. SB 408), the parties to the settlement agreed that Avista could write-off the deferred state income tax balance. This was described in Order 11-119 issued on April 11, 2011 as follows:

> "The Stipulating Parties also agreed that Avista could eliminate a liability in the amount of $911,709 for deferred state income taxes from its books. This balance accumulated as a result of Avista's use of the normalization method for recording state income taxes in Oregon. Because the flow-through method of accounting was used in setting customer rates, customers did not contribute to the accumulation of this balance. Thus, removing this balance improves Avista's earnings, but does not affect customer rates."

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	07/09/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 180	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

REQUEST:

Referring to Avista/500, Smith/28 at 15-20 and 29 at 1-5, please explain:

a. Whether the Company has any Oregon state income tax net operating losses available for carryback or carryforward.
b. Whether Avista included accelerated depreciation deductions in its estimation of Oregon SIT for the 2016 test year.
    i. If not, please explain why not; and,
    ii. If so, please explain how Avista incorporated bonus and section 179 depreciation into its forecasted FIT and SIT for the 2016 test year.

RESPONSE:

a. The Company did not have any Oregon state income tax net operating losses available for carryback or carryforward, as shown on the 2013 Oregon State Income Tax Return, which was provided in response to Staff_DR_176. The 2014 tax return has not been prepared, however, the Company does not anticipate a net operating loss.

b. The Company provided the calculation of its estimated Oregon SIT for the 2016 test year in the original filed case (Smith workpapers). A copy is provided on page 2 of this response.
    i. As described in Note (2) below, accelerated depreciation of $41,652,584 (system level before applying Oregon's apportionment factor) was factored into the 2016 estimate. This was based on the 2014 accrual, which is the best information at this time.
    ii. As described in response to Staff_DR_179, the Company does not use Section 179 deductions. As described in Note (3) below, the Company factored in $0 bonus depreciation deduction, since that deduction is no longer available after 2014. Please see response to Staff_DR_179 that describes the Company's use of bonus depreciation.

Avista Utilities
Oregon SIT

	2014 Actual	2015 Estimate	2016 Estimate	Notes
Corp Pre-Tax Income (2015/2016 per forecast)	179,408,135	183,159,000	204,518,000	
Less: Forecasted GRC Revenue			(52,934,000)	(1)
Adjusted Corp Pre-Tax Income	179,408,135	183,159,000	151,584,000	
Schedule M's				
Non-Plant	35,198,171	35,198,171	35,198,171	(2)
Plant - Tax Deprec over book	(41,652,584)	(41,652,584)	(41,652,584)	(2)
Plant - Bonus Depreciation	(90,000,000)			(3)
Plant - Repairs for prior years	(125,909,739)			(4)
Plant - Repairs for current year	(28,593,225)	(28,593,225)	(28,593,225)	(4)
Total Schedule M's	(250,957,377)	(35,047,638)	(35,047,638)	
Corp. Taxable Income	(71,549,242)	148,111,362	116,536,362	
Oregon Apportionment Factor	10.780%	10.780%	10.780%	
Oregon Taxable Income	(7,713,008)	15,966,405	12,562,620	
Oregon SIT Rate	7.600%	7.600%	7.600%	
Oregon SIT	(586,189)	1,213,447	954,759	
Less: Oregon BETCs (See attached spreadsheet)	0	(1,099,868)	(11,558)	
Net Oregon Taxes	(586,189)	113,579	943,201	
Oregon Natural Gas Allocation Factor	75%	75%	75%	
Natural Gas SIT	(439,641)	85,184	707,401	
Less: Test Period SIT			(416,386)	
Adjustment			1,123,787	

Notes:

(1) The forecasted GRC revenue is removed from the accrual, since the SIT for revenue from this GRC will be calculated with the SIT rate in the conversion factor.

(2) The Schedule M adjustments will be materially the same in 2015 and 2016

(3) Bonus depreciation is not forecasted, since it has not been approved by IRS.

(4) The repairs adjustment in 2014 was made up of: a) a one-time adjustment for 2010 - 2013, and b) the 2014 adjustment that will be available in 2015 and future years.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/06/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 214	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

REQUEST:

Referring to the Company's workpaper, 1) SIT Calculation 2014.xlsx , tab, 2016 Test Period, and Staff's attached spreadsheet file, Avista UG 288 DRs 214 Attachment A.xlsx, please modify Staff's spreadsheet file as follows:

a. In the columns labeled, 2004 through 2013, inclusive, please populate with the actual data for those years in the same manner as the Company provided for 2014 through 2016; and,
b. In rows 45 through 58, there is listed additional Oregon state income tax information that Staff would like the Company to provide grouped by report type; Result of Operations reports, General Ledger year end results, and tax credit schedule. Please provide the data for the calendar years 2004 through 2016, inclusive.

If the information is unavailable, please explain..

RESPONSE:

The Company has provided the historical information, as requested, except for 2004 in Staff_DR_214-Attachment A. The Company does not have a copy of the 2004 Federal Tax Return. In addition, the Company began using its Oracle accounting/financial system on January 1, 2005, therefore, information prior to 2005 is not readily available.

CASE: UG 288
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	06/01/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Gardner	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Fed. Regulation
REQUEST NO.:	Staff – 135	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

REQUEST:

Topic or Keyword: bonus depreciation, Accumulated Deferred Federal Income Tax (ADFIT)
Referring to Exhibit No. 501, Avista/501, Smith, 1-11 at 242, please explain if the Total Accumulated DFIT amount includes a depreciation timing difference arising from bonus depreciation for any of the years 2014, 2015 or the 2016 test year. If not, please explain why not. If so, please explain how bonus depreciation was incorporated into the rate case.

RESPONSE:

An estimate of 2014 bonus tax depreciation was recorded in December 2014. The estimate was prepared based on information available at that time, but it will be subject to change as the final, more detailed calculation is prepared in preparation for the September 2015 filing of the company's 2014 federal tax return. Results of Operations (December 31, 2014 AMA) used as the base year in this rate case included the ADFIT associated with the 2014 estimated bonus depreciation on an AMA basis. The Company adjusted the AMA balance to an end-of period December 31, 2014 balance with Adjustment 2.05. The Company adjusted the December 31, 2014 EOP balance to an EOP December 31, 2015 balance with Adjustment 2.06.

Bonus depreciation was enacted as a temporary measure to help the ailing U.S. economy. It was originally scheduled to expire on December 31, 2008. However, due to the continuing bad economy, it had been continually extended by Congress, which enacted annual "tax extender" bills to continue it and certain other popular tax breaks each year. Congress failed to pass a tax extender bill in 2013 and 50% bonus depreciation expired at the end of 2013. Congress passed a tax extender package on December 16, 2014 which included an extension of 50% bonus depreciation through the end of 2014.

Because the credit expired, the Company has not incorporated any bonus depreciation for 2015 or 2016 in its filing.

CASE: UG 288
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

October 16, 2015

Baker Tilly

Insights

July 24, 2015

Articles

Bonus depreciation update for 2015

In July 2015, the Senate Finance Committee voted 23 to 3 to extend bonus depreciation and the enhanced section 179 deduction through 2016. The full Senate has not indicated if or when it will act on this legislation and the House is not scheduled to take up extenders until the fall. In December 2014, Congress retroactively extended bonus depreciation and the $500,000 limit for a section 179 deduction through 2014.

Bonus depreciation may result in substantial present value tax savings for businesses that already had plans to purchase or construct qualified property. Unlike section 179 expensing, you do not need net income to take bonus depreciation deductions. Further, bonus is not limited to smaller businesses or capped at a certain dollar level, but it is not available for used property, property used outside of the US, tax-exempt use property, or tax-exempt financed property. Also, many states are likely to opt out of this provision for state income tax purposes.

Bonus depreciation has generally been available since Sept. 11, 2001, with a period of expiration in 2005, 2006, and 2007, and has ranged from 30 percent to 100 percent over the years, as shown in this chart:

Start date	End date	Bonus amount
9/11/2001	5/5/2003	30%
5/6/2003	12/31/2004	50%
1/1/2008	9/8/2010	50%
9/9/2010	12/31/2011	100%
1/1/2012	12/31/2014	50%

Tax Insights
from Washington National Tax Services

Senate Finance Committee approves renewal of expired tax provisions

July 21, 2015

In brief

The Senate Finance Committee today voted 23 to 3 to approve legislation to extend more than 50 expired tax provisions, including key business provisions such as the Section 41 research credit, bonus depreciation, the exception for Subpart F financing, look-through treatment of payments between related controlled foreign corporations (CFCs), and increased Section 179 "small business" expensing limitations. The bill is similar to the one-year tax extender legislation enacted late last year, but would provide a two-year retroactive extension of certain expired tax provisions from January 1, 2015 through December 31, 2016. The Joint Committee on Taxation staff estimates the bill would cost approximately $95.2 billion over 10 years, after taking into account $1.8 billion in revenue offsets.

Finance Committee Chairman Orrin Hatch (R-UT) said it was important to move the tax extenders package forward as quickly as possible. He added that the Committee "should be working to make a number of these tax extender provisions permanent," but that the debate about permanence should be deferred until a later time.

Earlier this year, the House passed legislation to extend permanently and modify the research credit. The House also has passed legislation this year to extend permanently increased Section 179 expensing limits, certain S corporation provisions, certain charitable giving provisions, and the federal deduction for state and local sales taxes. House Ways and Means Chairman Paul Ryan (R-WI) recently said that he hopes to address other tax extenders in September. For more on recent House action to address expired tax provisions, see our May 21 Tax Insight.

In detail

The Finance Committee on July 21 approved legislation that retroactively extends for two years -- from January 1, 2015 through December 31, 2016 -- certain business and individual tax provisions that expired at the end of 2014.

Significant expired business provisions that would be extended through the end of 2016 include the research credit, look-through treatment of payments between related controlled foreign corporations (CFCs), and the Subpart F active financing exception. The bill also would renew 50-percent bonus depreciation for qualified property and would continue to allow an election to accelerate AMT credits in lieu of bonus depreciation.

Additional business tax provisions that would be extended through 2016 include the following:

- New markets tax credit, with modifications
- Work opportunity tax credit, with modifications
- 15-year straight-line cost recovery for qualified

leasehold improvements, qualified restaurant buildings and improvements, and qualified retail improvements

- 7-year recovery period for motorsports entertainment complexes
- Increased expensing limitations and treatment of certain real property as Section 179 property
- Special expensing rules for certain film, television, and theatrical productions
- Deduction allowable with respect to income attributable to domestic production activities in Puerto Rico
- Treatment of certain dividends of regulated investment companies (RICs)
- Treatment of RICs as "qualified investment entities" under the Foreign Investment in Real Property Tax Act (FIRPTA)
- Special rules applicable to qualified small business stock
- Reduction in S corporation recognition period for built-in gains tax
- Basis adjustment of S corporations making charitable contributions of property
- Increase in limit on cover over of rum excise tax revenues to Puerto Rico and the Virgin Islands
- Economic development credit for American Samoa
- Qualified zone academy bonds
- Enhanced charitable deduction for contributions of food inventory.

Additional energy tax provisions that would be extended through 2016 include the following:

- Beginning-of-construction date for renewable power facilities eligible to claim the electricity production credit or investment credit in lieu of the production credit
- Credit for construction of energy-efficient new homes
- Energy-efficient commercial building deduction, with modifications.

Individual tax provisions that would be extended through 2016 include the following:

- Deduction for state and local sales taxes
- Exclusion for discharge of indebtedness income on principal residences
- Parity in the exclusion for employer-provided mass transit and parking benefits and treatment of bicycle-sharing programs as transportation fringes
- Tax-free distributions from IRAs to certain public charities for individuals age 70-1/2
- Contributions of capital gain real property made for qualified conservation purposes
- Above-the-line deduction for certain teacher classroom expenses.

Amendments considered by the Finance Committee

Finance Committee members filed over 100 amendments to the original bill. Chairman Hatch incorporated some of these amendments into a modified Chairman's Mark, released the morning of the Finance Committee's July 21 markup.

The revised Chairman's Mark includes language modifying the research credit to allow qualifying small businesses to claim the credit against payroll taxes, for taxable years beginning after December 31, 2014. This benefit would be capped at $250,000 per year and would be available only to companies less than five years old with less than $5 million in gross receipts. In addition, this amendment would allow certain taxpayers to offset the research credit against liability for the alternative minimum tax (AMT).

The modified Chairman's Mark also added $1.8 billion in revenue offsets. These offsets would:

- Exclude from gross income certain clean coal power grants
- Modify the alternative fuels credit and excise tax for liquefied natural gas and liquefied petroleum gas
- Modify information reporting requirements for mortgage lenders.

Note: The House on July 15 approved a similar mortgage lender information reporting provision as part of Highway Trust Fund legislation.

The Committee adopted by voice vote an amendment offered by Senator Charles Grassley (R-IA) to convert the biodiesel fuels credit from a mixture credit to a production credit, and an amendment offered by Senator Debbie Stabenow (D-MI) to modify tax rules that exclude from gross income the discharge of certain qualified principal residence indebtedness.

Several amendments were offered and then withdrawn by Finance

Committee members who indicated their intent to pursue action on their proposals at a future date. These included amendments to make permanent bonus depreciation and certain other provisions, and amendments to eliminate or phase out the production tax credit and certain other renewable energy tax incentives.

Click here for information on the Finance Committee tax extenders legislation.

The takeaway

Approval of tax extenders legislation by the Senate Finance Committee is a significant step toward renewing expired business and individual tax provisions, although the timing of further action by the full Senate on tax extenders this year remains uncertain. The House and Senate also will need to reconcile their differing approaches to tax extender legislation.

Let's talk

For a deeper discussion of how this might affect your business, please contact:

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Tax Insights
from Washington National Tax Services

House of Representatives approves permanent extension of bonus depreciation

July 11, 2014

In brief

The House today voted 258 to 160 to approve a bill (H.R. 4718) to permanently extend and modify on a retroactive basis Section 168(k) 50-percent bonus depreciation. The Joint Committee on Taxation (JCT) estimates that the proposed permanent bonus depreciation provision would reduce federal revenues by $262.9 billion over 10 years. H.R. 4718 also would expand the election to accelerate alternative minimum tax (AMT) credits in lieu of bonus depreciation; JCT staff estimates this provision would reduce federal revenues by $24.5 billion over the same period.

Today's action by the House is part of an ongoing effort by the House Ways and Means Committee to make permanent select expired tax provisions, including the research credit, 'look-through' treatment for controlled foreign corporations, Subpart F exceptions for active financing income, certain S corporation provisions, a group of charitable provisions, and individual tax provisions dealing with education and the child tax credit. For more on recent House actions on permanent tax extender bills, see our June 25 WNTS Insight.

In contrast, the Senate Finance Committee in early April approved an $85 billion 'tax extenders' bill (S. 2260) that would temporarily extend bonus depreciation and more than 50 other expired or expiring tax provisions on a retroactive basis through the end of 2015. Senate efforts to act on the Finance tax extenders bill have been delayed due to a lack of agreement on which floor amendments could be considered. For more on the Senate Finance Committee bill, see our April 3 WNTS Insight.

The outlook for final legislative action on expired tax provisions remains unclear. At this time, final action on tax extenders is not expected to occur until after the November midterm Congressional elections.

In detail

Permanent bonus depreciation

During House floor debate, Ways and Means Chairman Dave Camp (R-MI) noted the support of various business groups for permanent extension of bonus depreciation.

"Bonus depreciation has received long-standing bipartisan support and has been renewed on a short-term basis for nine out of the last 12 years," Chairman Camp noted. "After so many years of this policy being in place, it is time for us to agree that we should make it permanent so businesses can do what they do best – invest in the economy and hire new workers."

H.R. 4718 makes permanent the 50-percent additional first-year depreciation deduction for qualified property. The bill also expands the definition of qualified property to include qualified retail improvement property.

Under H.R. 4718, the $8,000 increase in the limitation on the depreciation deductions allowed with respect to certain passenger automobiles is indexed for automobile price inflation. The increase does not apply to a taxpayer who elects to accelerate AMT credits for a taxable year.

H.R. 4718 also makes permanent the special rule for the allocation of bonus depreciation to a long-term contract.

H.R. 4718 makes permanent and modifies the election to increase the AMT credit limitation in lieu of bonus depreciation. Under the bill, the bonus depreciation amount for a taxable year is limited to a lesser of (1) 50 percent of the minimum tax credit for the first taxable year ending after December 31, 2013 (determined before the application of any tax liability limitation), or (2) the minimum tax credit for the taxable year allocable to the adjusted net minimum tax imposed for taxable years ending before January 1, 2014 (determined before the application of any tax liability limitation and determined on a first-in, first-out basis).

H.R. 4718 provides that in the case of a partnership having a single corporate partner owning (directly or indirectly) more than 50-percent capital and profits interests in the partnership, each partner takes into account its distributive share of partnership depreciation in determining its bonus depreciation amount.

In addition, H.R. 4718 includes special rules for a taxpayer to claim bonus depreciation on trees or vines bearing fruits and nuts.

Effect on the economy

The Ways and Means Committee report for H.R. 4718 includes a Congressional Budget Office (CBO) macroeconomic analysis of the bill's effect on the US economy. CBO staff projects the bill will result in a small increase in business capital stock and in US gross domestic product (GDP), relative to present law.

According to CBO's analysis, the 50-percent expensing of certain investment expenditures provided for in this bill will increase the after-tax rate of return for investment in qualified expenditures, providing an incentive for increased investment in qualified capital. CBO staff also indicates that the bill provides an incentive for some substitution away from housing investment toward qualified investment – mostly business equipment.

Click here for a copy of H.R. 4718, and click here for copy of the Ways and Means Committee report, which also includes technical explanations and revenue estimates provided by JCT staff.

White House veto threat

A July 10 White House statement said that the "Administration strongly opposes House passage of H.R. 4718," and indicated that President Obama would veto the bill if it were presented to him by Congress. The statement notes that bonus depreciation was enacted previously to "provide short-term stimulus to the economy." The statement also indicates that the Administration opposes H.R. 4718 because it "includes no offsets and would add $287 billion to the deficit over the next 10 years, wiping out more than one third of the deficit reduction achieved by the American Taxpayer Relief Act of 2013."

The takeaway

Congress must reconcile differences between the House and Senate before any final legislation can be sent to the White House for action by President Obama.

It remains unclear whether Congress will include any permanent tax law changes in legislation addressing expired tax provisions. At the same time, House passage of a permanent bonus depreciation bill and Senate Finance Committee approval of a two-year temporary bonus depreciation extension increases the likelihood that the provision will be extended at least temporarily as part of any final legislation addressing expired tax provisions.

Final action on tax extenders currently is not expected to occur until after the November midterm Congressional elections.

Let's talk

For a deeper discussion of how this might affect your business, please contact:

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CASE: UG 288
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Opening Testimony

October 16, 2015

	A	B	N	O	P	Q	R	S
1								
2	Avista Utilities							
3	Oregon SIT		Provided by Company			OPUC Staff Projections		
4			2015	2016		2015	2016	
5			Estimate	Estimate	Notes	Staff Estimate	Staff Estimate	Staff notes
6	Corp Pre-Tax Income (2015/2016 per forecast)		183,159,000	204,518,000		183,159,000	204,518,000	
7		Less: Dividends				(50,999)	(50,999)	Included dividends since Avista regularly pays dividends
8		Less: Forecasted GRC Revenue	0	(52,934,000)	(1)		(52,934,000)	Avista 2016 forecast
9	Adjusted Corp Pre-Tax Income		183,159,000	151,584,000		183,108,001	151,533,001	
10								
11	Schedule M's							
12		Non-Plant	35,198,171	35,198,171	(2)	35,198,171	35,198,171	2014 actual
13		Plant - Tax Deprec over book	(41,652,584)	(41,652,584)	(2)	(41,652,584)	(41,652,584)	2014 actual
14		Plant- Bonus Depreciation			(3)	(90,000,000)	(90,000,000)	Staff assumes bonus depreciation will be extended for 2015 & 2016. Used Company 2014 actual to estimate.
15		Plant - Repairs for prior years			(4)			n/a
16		Plant - Repairs for current year	(28,593,225)	(28,593,225)	(4)	(28,593,225)	(28,593,225)	2014 actual
17	Total Schedule M's		(35,047,638)	(35,047,638)		(125,047,638)	(125,047,638)	
18								
19	Corp. Taxable Income		148,111,362	116,536,362		58,060,362	26,485,362	
20		Add: State Excise Tax			missing from			
21		Add: Other			accrual			
22	Revised Corp. Taxable Income		148,111,362	116,536,362		58,060,362	26,485,362	
23								
24	Oregon Apportionment Factor		10.780%	10.780%		10.151%	10.151%	Average 2011-2013
25								
26	Oregon Taxable Income		15,966,405	12,562,620		5,893,959	2,688,644	
27		OR Apportionment of NOL C/F						
28			15,966,405	12,562,620		5,893,959	2,688,644	
29								
30	Oregon SIT Rate		7.600%	7.600%		7.430%	7.228%	Staff calculated SIT rate for revenue sensitive
31								
32	Oregon SIT		1,213,447	954,759		437,941	194,337	OR tax calc = (Multiply taxable income greater than $1M by X 7.6%) plus $66,000
33	Less: Oregon BETCs (See attached spreadsheet)		(1,099,868)	(11,558)		(437,941)	(194,337)	
34	Net Oregon Taxes		113,579	943,201		0	0	
35								
36	Oregon Natural Gas Allocation Factor		75%	75%		75%	75%	
37								
38		Natural Gas SIT	85,184	707,401		0	0	
39								
40								
41	Less: Test Period SIT			(416,386)			-	
42								
43	Adjustment			1,123,787			(1,123,787)	Staff proposed adjustment to Avista's Restated AMA 2016 Test Year
44								
45			2015	2016		2015	2016	
46		Staff DR 214 a	Estimate	Estimate	Total	Staff Estimate	Staff Estimate	Total
47		**Results of Operations Reports (use data from filed ROO for 2004-2014, and filed GRC for 2016)**						
48		Oregon SIT from ROO-Column A						
49		Oregon Deferred SIT included in Accumulated Deferred Income Tax-Column A						
50								
51		**General ledger (year end results)**						
52		Oregon SIT expense (Oregon jurisdiction-situs & allocated)						
53		Oregon accumulated deferred income tax (Oregon jurisdiction - situs and allocated)						
56								
57		**Tax Credit Schedule**						
58		Oregon tax credit beginning balance	831,136	(1)		831,136	661,927	
59		Oregon tax credits generated	250,000	-	2,897,161	250,000	-	
60		Oregon tax credits generated-used to offset capital project			492,049			
61		Oregon tax credits purchased	18,731	11,558	1,195,057	18,731	11,558	
62		Oregon tax credits used	(1,099,868)	(11,558)	(4,584,267)	(437,941)	(194,337)	
63		Oregon tax credits expired						
64		Oregon tax credits ending balance	(1)	(1)	(0)	661,927	479,147	
65								
68	Notes:							
69	(1)	The forecasted GRC revenue is removed from the accrual, since the SIT for revenue from this GRC will be calculated with the SIT rate in the conversion						
70	(2)	The Schedule M adjustments will be materially the same in 2015 and 2016						
71	(3)	Bonus depreciation is not forecasted, since it has not been approved by IRS.						
72	(4)	The repairs adjustment in 2014 was made up of: a) a one-time adjustment for 2010 - 2013, and b) the 2014 adjustment that will be available in 2015 and future years.						
73								

CASE: UG 288
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

October 16, 2015

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

A. My name is Matt Muldoon. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is: 201 High Street, Suite 100, Salem, OR 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement can be found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I am responsible for three Cost of Capital (CoC) issues in this docket:

1. Capital Structure,
2. Cost of Common Equity, also known as Return on Equity (ROE), and
3. Cost of Long-Term (LT) Debt.

Q. What is your summary recommendation?

A. I recommend a 49.86 percent equity capital structure, Avista Corporation's (AVA, Avista or Company) ROE of 9.11 percent, and a 5.515 percent Cost of LT Debt.

Q. Did you prepare tables showing current, Avista-proposed and Staff proposed overall CoC?

A. Yes, the following three tables provide that information.

Table 1

AVA Current OPUC Authorized (UG 284 Order No. 15-109)			AVA
Component	Percent of Total	Stipulated or Implied Cost	Weighted Average
Long Term Debt	49.00%	5.452%	2.671%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	51.00%	9.50%	4.845%
	100.00%		7.516%

Table 2

AVA Requested – UG 288		AVA Direct Testimony		
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50.00%	5.53%	2.765%	0.199%
Preferred Stock	0.00%		0.000%	
Common Stock	50.00%	9.90%	4.950%	
	100.00%		7.715%	

Table 3

Staff Proposed – UG 288		Opening Testimony		
Component	Percent of Total	Cost	Weighted Average	ROR vs. Current
Long Term Debt	50.14%	5.515%	2.765%	-0.209%
Preferred Stock	0.00%		0.000%	
Common Stock	49.86%	9.110%	4.542%	
	100.00%		7.307%	

ISSUE 1 – CAPITAL STRUCTURE

Q. What is the basis for your recommendation for 49.86 percent equity and 50.14 percent LT Debt capital structure?

A. I have three reasons for supporting my recommended capital structure:

1. This is my best estimate of capital structure at end of the 2016 test year inclusive of the results of two successive stock buyback programs.
2. This capital structure is within the range that optimizes the Company's financial performance balanced against the risk of leverage.
3. This capital structure excludes elements not historically considered LT Debt by the Commission. My recommended LT Debt portion of the capital structure excludes short term debt with maturities less than one year and imputed debt from the Company's contracts, consistent with ORS 757.415(3).[1]

ISSUE 2 – COST OF COMMON EQUITY (ROE)

Q. Avista is requesting an ROE of 9.9 percent. This recommendation is based in part on the Company's ROE witness Mr. Adrien McKenzie's results of analysis estimating a 9.6 to 10.9 percent ROE range.[2] What are the primary reasons for the difference between the Company's requested 9.9 percent ROE and your recommended 9.11 percent ROE?

A. The primary reasons for the differences between the Company's request and my recommended ROE are because the Company:

- Relies heavily on models such as constant growth — single stage — Discounted Cash Flow (DCF) model of Professor Myron J. Gordon and Empirical Capital Asset Pricing Model (Empirical CAPM). These models

[1] Staff notes that Washington Utility and Transportation Commission (WUTC) proceedings, Avista investor presentations, and the Company's quarterly 10-Q and annual 10-K reporting to the U.S. Security and Exchange Commission (SEC) concerning capital structures and debt listings do include short-term and imputed debt. When such elements are backed out, data therein matches Staff findings herein.

[2] See Avista/300, McKenzie/5.

have merited no weight before the Commisison in recent general rate cases.

- Fails to anticipate lower than historical long-term gross domestic product (GDP) growth rates.
- Relies in part on electric and non-utility stocks rather than gas peers.
- Fails to anticipate certain mergers and acquisitions in its gas peer group.
- Removes the low end of modeling estimates while retaining upper estimate outliers.[3]
- Relies on high estimates of risk premiums distorting Capital Asset Pricing Model (CAPM) modeling.
- Makes outboard size adjustments normally addressed within selection of peer groups to shift modeling results up by 80 basis points (bps).[4]
- Relies on Dr. Roger Morin's "Empirical CAPM" or (ECAPM). Were no unusual adjustments used in the basic CAPM model, CAPM returns a lower required ROE than Staff recommends. ECAPM (a method not commonly used by finance academics and professionals) presumes that the security market line could be pivoted at a designated point until a reasonable result is obtained. The argument is that a properly pivoted CAPM model will correct for CAPM's flaws. Essentially this is a method that augments CAPM ROE by a minimum of 50 bps.

Q. How is your testimony organized?

A. My testimony is organized as follows:

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3 As an example, please see Avista/300, McKenzie/39 at lines 6-7.

4 *See* Avista/300, McKenzie/54-55.

Q. Did you prepare exhibits in support of your opening testimony?

A. Yes. I prepared the following exhibits:

Staff/202 .... Staff Peer Screening
Staff/203 .... Staff Three Stage DCF Modeling
Staff/204 .... Treasury Inflation Protected Securities (TIPS) Analysis
Staff/205 GDP Analysis with U.S. Bureau of Economic Analysis (BEA) Data
Staff/206 .... Staff CAPM Modeling
Staff/207 **CONFIDENTIAL** Cost of LT Debt Table & Maturity Profile
Staff/208 .. Southern Co.'s Proposed Acquisition of AGL Resources
Staff/209 .... Value Line (VL) Gas and Water Utility Profiles
Staff/210 .... Security Market Trends
Staff/211 .... Frequency of Gas Utility Rate Case Filings
Staff/212 .... SNL Overview of Energy Utility Rate Case ROEs
Staff/213 .... Avista Investor Presentation for 2015 Q2.

Q. Does your recommended ROE meet appropriate standards?

A. Yes. The 9.11 percent ROE I recommend meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statute (ORS) 756.040. My recommendations are consistent with establishing "fair and reasonable rates" that are both "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[5]

Q. Are these the same standards discussed in Avista's testimony?

A. Yes. Staff and Avista apply the same legal standards. However, Avista and Staff disagree on what ROE is commensurate with that of other utilities and other investment opportunities with risk exposure similar to Avista's. When investors' expected rate of return is measured using a reasonable expectation of long-term growth, and when risk is measured using an appropriate peer group of utilities, the resulting ROE is within the range recommended by Staff.

WHAT IS NEW IN THIS RATE CASE

Q. What is new in this third general rate case that Avista has filed in as many years?

A. I will discuss three considerations that newly-arise in this rate case:

First, this is the Company's third consecutive annual rate case. Only one other publicly traded U.S. gas utility has filed rate cases so frequently in the last decade, and none of the gas utilities in Staff's peer group have filed this often. Such frequent filing decreases Avista's risk of and time to cost recovery as compared to peer gas utilities. Please see Staff/211, Muldoon/1 for a full breakout of U.S. gas utility rate case filing frequency.

Second, projections of long-term growth rates by a broad consensus of U.S. Government, academic, business and analytic referent sources for U.S.

5 *See* ORS 756.040(1) (a) and (b).

gross domestic product (GDP) have been lowered since this past spring. The U.S. Federal Reserve's last estimate of September 18, 2015, projects the U.S. economy will grow yet slower between 1.8 percent and 2.2 percent in the long-run. Related to this is turbulence in the global markets. China's demand for raw materials plummeted this past summer, China's stock market in Shanghai dropped sharply, and China suddenly devalued its currency against the dollar. China's GDP growth was slowing by an uncertain but dramatic amount. Commodity prices dropped sharply. As many industrial commodities from copper to iron ore are priced in U.S. dollars, currencies of many global commodity exporting countries from Brazil to New Zealand dropped 20 to 40 percent against the U.S. dollar. Concerns about global markets and growth were sufficient to disrupt U.S. Federal Reserve (FED) monetary policy.

The third, and last, consideration is that merger and acquisition activity has reduced the pool of potential peer gas utilities available for this rate case's cost of capital modeling.

Q. As to your first consideration, frequency of rate case filings, do Staff's peer utilities in its ROE modeling file rate cases less frequently than does Avista?

A. In the last decade, only one of the gas utilities (in the pool from which Staff selected peers) filed three consecutive annual general rate cases. *See* Exhibit Staff/211. That gas utility did not pass Staff's peer screening.

Q. Please discuss your second consideration: predicted slower long-term growth rates and turbulence in the global markets.

A. John Lonski, Chief Economist of Moody's Capital Markets Research, Inc., on September 23, 2015, in "Credit Markets Review and Outlook" said that, "The world economy is in its worst shape since the Great Recession.

Q. According to the Wall Street Journal print edition of September 8, 2015, the U.S. has significantly less trade with China than much of the rest of the world, as shown in Figure 1 below. What indicates there is any sizable risk of contagion from stalled or contracting economies abroad?

Figure 1

A. Concerns rise beyond increased volatility in the U.S. Stock market in August to impacts on U.S. exports, U.S. Dollar exchange rates against other currencies and low inflation rates. FED Reserve Chair Yellen explained that the long-signaled increase in interest rates did not happen in significant part because of concerns surrounding GDP growth in China and impacts on the U.S. as well as global economies. With this explanation, it was clear that the U.S. economy and internal monetary policy were not entirely insulated from declining global economic conditions.

Q. How do the trends set forth above help or harm U.S. regulated utilities and Avista gas distribution operations in particular?

A. Interest rates staying low longer increases demand for U.S. dividend paying utility stocks. Demand for utility bonds remains strong, even in private placement markets. U.S. corporations have shifted cash reserves into highly rated U.S. corporate bonds in lieu of commercial paper and U.S. Treasury Securities (UST), seeking improved yields.[6] And the U.S. Investor Owned Utility (IOU) combination of domestic U.S. sales and a strong dollar minimizes exposure to global risks while affording access to low cost capital and construction materials.

Q. How do the trends discussed above affect Avista's CoC?

A. Continued investor flight to safety, and reduction in risk and regulatory lag, merit a lower point ROE from within a range of reasonable ROEs. For example: the Maryland Commission recently found that a company that

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6 See the September 25, 2015, WSJ Article, "Big Buyers of Corporate Bonds: Other Corporations" by Vipal Monga.

engages in consecutive annual filings merited a lower than top end of range ROE due to the reduced risk.[7]

Global uncertainty prolongs a long period of investor flight to the quality and safety of U.S. regulated "investor owned utilities" (IOU) securities preserving continued utility access to capital at historically attractive costs.

Q. Please continue with your discussion of lower long-term growth predictions.

A. A broad, consensus of federal government agencies, economists and referent experts now project substantially lower long-term growth in U.S. GDP. Paired with another broad consensus that growth in U.S. gas sales will be less than the rate of GDP growth, this trend has serious implications not yet considered in Avista's last rate case. This trend of reduced growth projections from the prior year is summarized in Figure 2.

Figure 2

Growth Trends	Now	Prior	Difference
Tips Inflation Forecast	2.12%	2.35%	**-0.23%**
EIA	4.57%	4.89%	**-0.32%**
OMB	4.30%	4.61%	**-0.31%**
CBO	4.20%	4.55%	**-0.35%**
Composite	4.71%	5.02%	**-0.31%**
Historical 1980 – 2014	5.05%	5.35%	**-0.30%**
Indiana / Top 10 Blue Chip	5.08%	5.78%	**-0.70%**

**Even Most Optimistic 1 in 10 Referent Experts
No Longer Project Upbeat LT Growth**

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7 Public Service Commission of Maryland, Order No. 85374, Case No. 9299, at 78 (February 22, 2013).

Q. What is the primary effect of projected lower long-term growth in your modeling?

A. All else held constant in Staff's current modeling, the reduction in projected long-term GPD growth translates into a 31 basis point downward shift in the range of reasonable ROEs for Avista.

Q. Have all these experts maintained their spring projections?

A. Growth projects have variously stayed at the spring levels or declined further since then. Staff's modeling may not fully capture the downward trending.

Q. Could you recap some of the underlying causes for this decline in long-term GDP growth projections?

A. Ruchir Sharma, the head of emerging markets and global macro at Morgan Stanley Investment Management, suggests that three drivers may explain much of the decline in projected GDP growth:[8]

- Lower than historical birth rates and disrupted immigration policies now project to fewer working-age Americans 20 years from now;
- A decline in the rate of growth of productivity or output per worker is also a concerning factor; and
- The United States' (U.S.) population is both aging and living longer. Retiring persons represent a greater than historic burden on health care, pensions and their working-age children.

Q. What are some of the implications of current global economic conditions?

A. The flight to safe securities like utility stocks and utility bonds is driven in part by the following factors:

[8] Please see "How the Birth Dearth Saps Economic Growth" by Ruchir Sharma in the print edition of the WSJ for September, 25, 2015.

- Lower expected UST yields increase the attractiveness of U.S. utility security issues;[9]
- Decreased global demand for commodities has stressed emerging market economies and currencies, thereby increasing demand for select safer U.S. issues.[10] The majority of securities were issued in the U.S. in the past year. In this time, according to the Wall Street Journal (WSJ), U.S. banks have captured half of all global banking revenue.[11]
- Companies and investors lack a clear signal of where they are in the business cycle, impairing investment by Companies in durable goods, injecting external considerations into FED policy, and prompting investor caution.[12]
- FED Chair Yellen's clear and detailed explanations of FED actions and expectations depicted a downward adjustment to June's long-term outlook. Chair Yellen also shared that despite the intention to raise rates several times in the next 18 months, U.S. monetary policy would be "highly accommodative for quite some time."[13]
- China's economic challenges and government responses unsettled global markets and investors alike.[14]

The general conclusion is that recent events and the FED delay in raising interest rates are positive for U.S. regulated utilities.[15] *See* Staff/211.

Q. How do you recommend the Commission address this economic decline?

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9 See the September 25, 2015, WSJ article by Ming Zeng, "Treasury Yields Fall as Inflation Fears Diminish".

10 See the WSJ articles: "Brazil's Real Hits Two-Decade Low" by Carolyn Cui and Paulo Trevisani published in the print edition on September 23, 2015; and "Emerging Markets Hit Hard as Global Rout Continues" by Andrey Ostroukh and Patrick McGroarty on August 25, 2015.

11 See" U.S. Banks Rack Up Fees" in the WSJ MoneyBeat Column of September 28, 2015.

12 See "How the World is Messing with the FED" by Justin Lahart in the September 26, 2015 WSJ; "Slow Global Growth Shows Policy Limits" by Ian Talley in the September 18, 2015, WSJ; "Utilities Regain Favor, Broad Markets Withdraw as FED Postpones Rate Move" by Brian Collins published jointly on September 21, 2015 by Regulatory Research Associates (RRA) and SNL Financial LC (SNL);

13 See "Growth, Inflation Predictions Scaled Back" Associated Press, in the Oregonian on September 18, 2015.

14 See "China Central Bank Cuts Interest Rates" by Lingling Wei in the August 215, 2015 WSJ;

15 See "Wall Street Says FED's Rate Decision is Good for Utilities" by Darren Sweeney of SNL Financial LC on September 18, 2015.

A. Staff's analysis shows multiple growth rate levels. Staff recommends a 9.11 ROE that is in the midpoint of a reasonable range of ROEs, allowing for further corroboration of a substantial downshift in American growth expectations. This is a conservative ROE given that the available evidence at this time supports a slower long-term growth rate. Moreover, Staff's assessment does not rely on lower modeling results associated with many of the Company's suggested peers, and instead finds that Staff's screened peer group best fits investor expectations. *See* Exhibit Staff/203.

Q. Are current economic conditions a pinnacle moment for energy utilities?

A. Yes, there are three good reasons to believe financial conditions are near optimal now for U.S. utilities.

Q. What is the first of these reasons?

A. The first factor is insulation from global uncertainty. For example, Moody's points out that nearly all of regulated continental U.S. utility revenues and operating expenses are denominated in U.S. dollars. This provides a natural hedge against sustained U.S. dollar appreciation.

Q. What is the second of these reasons?

A. Continued low interest rates facilitate strategic investment to meet long-run utility needs, while making predictable dividend-paying equities more attractive to investors than global cyclical firms.

Q. And what is the third element?

A. Investor-stressing economic news continues to extend the investor “flight to quality/safety” freezing current conditions just right for regulated investor-owned utilities.[16]

Q. Are you suggesting the Commission should consider whether current economic conditions make jurisdictional utilities less risky than other potential investments?

A. Yes.

Q. Are you also suggesting that utilities that file multiple consecutive annual general rate cases and receive expedited cost recovery face even less risk?

A. Yes.

Q. Please discuss your third new consideration: the effect of mergers and acquisitions on your peer group.

A. There has been substantial utility merger and acquisition activity in the past year. Of particular note is Southern Company’s (Southern Co. or Southern) intent to purchase AGL Resources (AGL) for approximately eight billion dollars. Exhibit Staff/208 explains how the cash flows associated with AGL present an opportunity for Southern Co. to fund risky endeavors like new nuclear generating plants with internal funds. Staff’s sensitivity analysis ran

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[16] See “Economists’ Forecast: Here We Grow Again” by Kathleen Madigan, and “Why the Economy and the FED Keep Getting Knocked Off Track” by Jon Hilsenrath in the print edition of the WSJ for May 15, 2015. Articles like the above and “Workers’ “Productivity Declines Again” by Jeffrey Sparshott in the May 7, 2015, WSJ periodically deflate investor expectations for a return to pre-2008 economic conditions.

models with and without AGL. AGL is no longer a viable peer utility in the Company's modeling.

Q. Please summarize your testimony on these issues.

A. I discussed the following three new considerations since the last Avista general rate case: A) Frequent rate case filings have made Avista less risky than other U.S. gas utilities; B) U.S. long-term GPD growth projections have universally fallen due to fears regarding global financial stresses and lower U.S. productivity from an aging workforce; and C) Southern Co.'s purchase of AGL merits removal of AGL from Avista's modeling peers. Enough has changed since Avista's last general rate case, that the Commission may want to reduce Avista's point ROE substantially, depending in part on the Commission's confidence in current consensus economic forecasts of declining long-term GDP growth.

OVERVIEW OF ROE POSITIONS

Q. Describe the analysis underlying Staff's ROE recommendation.

A. I continue to rely primarily on two different multistage "discounted cash flow" (DCF) models,[17] applied using a cohort group of peer utilities, to estimate the expected return on common equity required by Avista investors. I compare the results of my DCF analysis with national historical gas utilities' authorized ROE values as a check on the reasonableness of my ROE estimates. I also input parameters from some of the models used by Avista witness McKenzie

[17] *See*, the Commission's discussion of multistage versus single-stage DCF models in Order No. 01-777 at page 27.

into Staff's models and contrast the analytic outputs with Avista witness McKenzie's results and with results from my two DCF models using Staff's inputs.

Q. What is a DCF model?

A. A DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation.

The ROE under the DCF model is the rate that equates the current stock price and expected cash flows to investors.[18] A DCF model has three primary components: a current stock price, an expected dividend, and an expected growth rate in dividends.[19]

Q. Describe the two DCF models that you used.

A. My first model is a conventional three-stage Discounted Dividend Model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (referred to as "Model X"). My second model is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (referred to as "Model Y").

Both models require, for each proxy company analyzed by Staff, a "current" market price per share of common stock, estimates of dividends per

[18] Order No. 01-777 at 26.

[19] Order No. 07-015 at 32.

share to be received in the years 2015 through 2019, annual rates of dividend growth from 2020 through 2024, and a long-term growth rate applicable to dividends beyond 2024.

The three stages of the models are: 1) 2015-2019, where I use Value Line's (VL) forecasts of dividends per share for each company; 2) 2019-2024, where the rate of dividend growth converges from the average rate over the 2015-2019 period to the growth rate in of the third stage; and 3) 2025-2044. This is the third "long-term" stage, for which growth rates are discussed.

Model X includes a terminal value calculation, in which I assume dividends per share grow indefinitely at the rate of growth in Stage 3 ("growing perpetuity"). In contrast, Model Y terminates in a sale of stock where the price is determined by my escalated price/earnings (P/E) ratio.

Q. Why did you use five years for Stages One and Two, and about 20 years for Stage Three?

A. I presume a 30-year horizon is relevant for investors. This is consistent with long-standing Staff practices including those of former Staff member Steve Storm in the NW Natural general rate case of Docket No. UG 221, which the Commission adopted in Order No. 12-408. This time frame allows for investor consideration of 30-year U.S. Treasury Long Bond and other alternate investment opportunities. I use five years for Stage One as that is the timeframe for which Value Line estimates of future dividends are available. I use five years for Stage Two as that seems a reasonable length of time for individual companies' dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all gas utilities. I discuss the mechanics of this convergence below. I use 15 to 20 years for Stage Three, corresponding to forward projections from federal sources, and calculate a terminal valuation for the sale of the Company's stock in 2043.

Q. How do you address dividend timing?

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values[20] produced with each set of calculations for each peer utility. This approach more closely replicates the "real world" quarterly receipt of dividends by investors; i.e., it takes into account the time value of money.

Q. What accounts for differences in peer capital structures?

A. Each model employs the Hamada equation[21] to calculate an adjustment for differences in capital structure between each peer utility and the Avista-proposed and Staff-assumed capital structure for Avista.[22] When few peer

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20 The technical term for each of these estimates is the "internal rate of return," or IRR.

21 Dr. Robert Hamada's Equation as used in Staff/202, Muldoon/4 separates the financial risk of a levered firm, represented by its mix of common stock, preferred stock, and debt, from its fundamental business risk. Staff corrects its ROE modeling for divergent amounts of debt, also referred to as leverage, between the Company and its peers.

22 Staff describes this adjustment in recent cost of capital testimony. *See*, as an example, Staff's description in Docket No. UE 233 Exhibit Staff/800, Storm/54-57.

utilities are available, the Hamada equation ensures Staff's analysis addresses differences in peer utility capital structures.

Q. What price do you use for each peer utility's stock?

A. I use the average of closing prices for each utility from the first trading day in April, May, and June 2015 to represent a reasonable snapshot of 2015, Q2.

Q. Did you review the impact of using prices from any other day of these months?

A. No.

Q. How do Staff's two DCF models differ?

A. Model X uses the calculation of a growing perpetuity as part of the terminal valuation in 2043. This may be the most common approach used in multistage DCF models.

Model Y uses the current price-earnings (P/E) ratio[23] multiplied by the estimated "earnings per share" (EPS) in 2043, which establishes the stock's "selling price" in 2043 for terminal valuation. I estimate the 2043 EPS analogously with methods used to estimate the 2043 dividend in both models; i.e., based on VL estimates to which multiple growth rates are sequentially applied.

Q. What is the purpose of Model Y?

A. I followed Staff's practice in recent rate cases of including this model as a method by which to incorporate the fact that most companies have estimates

[23] "Current" in this context means the price obtained, as previously described, divided by VL's estimated EPS; i.e., it is a forward P/E, not an historical P/E.

of future EPS and future dividends growing at different rates. Utilizing EPS that grows on a separate trajectory than dividends is the foundation for an alternative means of terminal valuation.[24]

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate Avista's ROE?

A. I used companies that met the following criteria as peer utilities to the regulated gas utility activities of Avista Corporation:

1. Covered by VL as an Gas Utility;
2. Forecasted by VL to have Positive Dividend Growth;
3. LT Issuer Credit Rating equal or better than BBB- from S&P, or Baa3 from Moody's;
4. No Decline in Annual Dividend in Last Five Years Based on SNL;
5. Has 80 percent or greater Regulated Assets;
6. Has LT Debt under 56 percent in VL Capital Structure; and
7. Has No Recent Merger and Acquisition Activity.

Q. Why do you eliminate companies that are not forecasted to have positive dividend growth?

A. I use the same screening practice that Staff has used in the past. There is evidence that investors find common stock of dividend-cutting utilities less attractive. The stock prices for FPL Group's Florida Power and Light and for

[24] Please note that the approach used in this second model is not the same as using a singular estimate of the growth rate in EPS as the growth rate in dividends.

Niagara Mohawk Power Corporation declined sharply after dividend cuts.[25] These real-world findings are consistent with Staff's screening out gas utilities that have recently cut dividends.

Q. Can gas utilities' common stock still enjoy active investment from global investors, who are looking for higher low-risk returns than the prevailing historically low-yielding global treasury bonds if they cease issuing predictable dividends?

A. Please see Staff/210, Muldoon/34 for a discussion of this topic. In general, many institutional investors and fund managers can substitute only very predictable bond-like stocks or very safe, highly rated bonds for UST without exposure to more risk than pertinent governance allows.[26]

Q. Is this currently a risky environment for interest rates?

A. There is uncertainty over that. Yield on the UST 10-year note shown above has fallen to 1.994 percent and the UST 30-year bond has fallen to 2.826 percent as posted by the WSJ on October 2, 2015, down from the rise shown in Figure 3 before the FED announced that it was not raising interest rates quite yet.

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[25] An example of investor reaction to dividend cuts is found in The New York Times article, "Niagara Mohawk Stock Dives After Dividend Suspension", published January 25, 1996.

[26] Yahoo Finance on September 26, 2015, showed that over 70 percent of shares in Avista are held by institutional investors and mutual funds.

Figure 3

Source: WSJ Aug. 11, 2015

US Treasuries (UST) Maturity		Units	Yield %
1	Months	Bill	0.0510
3	Months	Bill	0.1040
6	Months	Bill	0.2320
1	Years	Note	0.3600
2	Years	Note	0.6730
3	Years	Note	1.0050
5	Years	Note	1.5270
7	Years	Note	1.8890
10	Years	Note	**2.1430**
30	Years	Bond	**2.8100**

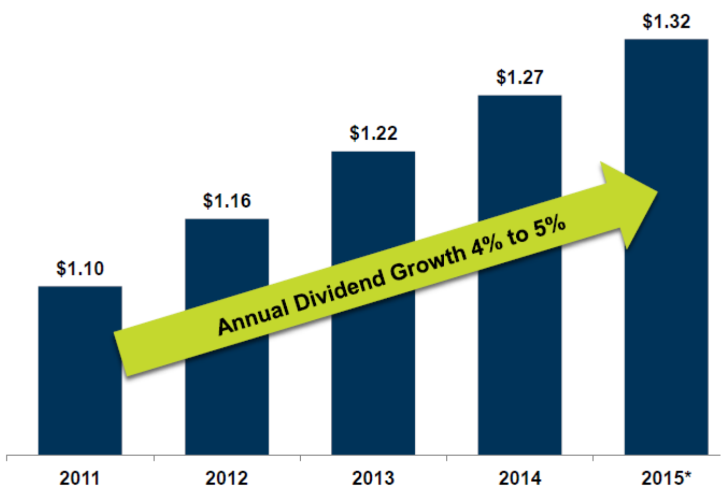
Source: WSJ Sep. 1, 2015

US Treasuries (UST) Maturity		Units	Yield %
1	Months	Bill	0.0080
3	Months	Bill	0.0430
6	Months	Bill	0.2670
1	Years	Note	0.3750
2	Years	Note	0.7120
3	Years	Note	1.0130
5	Years	Note	1.4990
7	Years	Note	1.8920
10	Years	Note	**2.1740**
30	Years	Bond	**2.9350**

Q. Is there evidence that Avista addressed these concerns in its communication with investors?

A. Yes. Avista's August 5, 2015 investor presentation provided in Staff/213, Muldoon/8 shows Avista can continue the dividend trend in Figure 4.

Figure 4 — Avista's June 5, Q1 Dividend Overview



Q. What cohort of companies resulted from your screens?

A. Please see Staff/202, Muldoon/1-2 for detailed Staff screens and also for a table that shows the list of peer utilities obtained from Staff screens and those obtained from Avista screens in this rate case

SENSITIVITY ANALYSIS

Q. After Avista filed this rate case did you perform sensitivities that removed gas utilities in the process of merging with other companies?

A. Yes, I performed model runs both with and without AGL Resources (AGL). Southern Company is in the process of purchasing AGL. *See* Staff/208.

Q. Did you also perform sensitivities that added water utilities able to pass Staff's screening methods to Staff's peer group?

A. Yes, IOU water utilities closely track average gas utility performance.

Q. How does Staff apply informed judgement to its modeling?

A. Staff examined its full range of ROE results from 8.03 percent to 9.45 percent after all adjustments. Within that range Staff determined that 8.31 percent to 9.45 percent was a reasonable narrowing of focus, excluding some of the Company's suggested peer companies. Further narrowing the focus to Staff's primary peers most like Avista was the best fit to capture investor expectations of Avista performance. Please note that this range also generates the highest modeling results, outperforming the Company's gas peer group.

Q. Does Staff's removal of the lower end of modeling results from 8.03 percent to 8.75 percent suggest Staff's results are fair, reasonable and conservative?

A. Yes, this is a representative indicator that Staff recommendations are balanced, fact-based and reasonable.

Q. Does running of these sensitivities replace or modify Staff's primary screening methods?

A. No, Staff's results address the proposed acquisition of AGL resources by Southern Co. and look at expanding the peer group with water IOUs, but the results of my sensitivity analyses merely better inform the Commission.

Q. Did the sensitivity of processing all of the Company peer utilities through Staff's three-stage DCF modeling provide useful information, including electric utilities and a variety of non-utility stocks?

A. No. Staff rejects the Company's use of electric utilities as gas distribution peers, consistent with prior Commission practice. Staff's higher results using Staff's gas peers than Company proposed gas peers suggests that Staff's results are unbiased and reasonable.

GROWTH RATES

Q. What is the single most important element of discounted dividend or DCF models when used to estimate investors' required ROE?

A. The estimated rate of growth of future dividends is most important element. I refer specifically to the singular growth rate for constant growth DCF models and the long-term growth rate for multistage DCF models such as those I use.

Q. What long-term growth rates did you use in the two DCF models?[27]

A. I used three different long-term growth rates, with different methods employed in developing each.

The first method uses a 50 percent weight applied to the average annual growth rate resulting from estimates of long-term GDP by the EIA, the OMB, and the CBO, with each receiving one-third of the 50 percent weight.[28] The remaining 50 percent is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2014,[29] to which I apply the TIPS inflation forecast.

The second long-term growth rate for Stage 3 dividends is a control reflecting Avista's Blue Chip & OMB growth rate.

The third Stage 3 annual growth rate, which I use primarily for illustrative purposes, is the Indiana / Top-10 Blue Chip most recent optimistic upper book-end projection as of April 2015.

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27 Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

28 The EIA is the Energy Information Administration within the U.S. Department of Energy (DOE), OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method described by Staff in testimony in multiple recent general rate case proceedings. See, as an example, in Docket No. UE 233 Exhibit Staff/800, Storm/50 line 4 through Storm/51 line 3. The TIPS forecast of annual inflation over the relevant Stage 3 timeframe is 2.12 percent, based on an average of interest rates for each of the months of April 2015, May 2015, and June 2015. It may be useful to think of the TIPS inflation rate forecast as a forward curve of dollars; i.e., market-based estimates of what a dollar will be worth in the future.

29 Staff discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. See, as an example, in Docket No. UE 233 Exhibits Staff/800, Storm/46, line 15 through Storm/50 line 3.

Q. This past August the CBO cut projected U.S. GDP growth forecasts.[30] **Did you lower your inputs from the CBO from its long-term spring forecast?**

A. No.

Q. This September, John Lonski, Chief Economist for Moody's Capital Research Inc. lowered GDP and earnings projections. Did you lower your modeling inputs based on these forecasts?

A. No, I did not.

Q. According to the Bloomberg's "Spring-2015 Consensus Estimate" from its survey of economists, the current upturn is expected to expire during 2018-2019, creating declines from earlier projections. Did you build these lower growth inputs into your modeling?

A. No.

Q. Duke University's Q3 2015 Survey of CFO's reflected further diminished Blue Chip expectations of growth from this past spring. Did you shift your long-term growth rates downward to reflect this new pessimism?

A. No. Staff continues to rely on the spring 2015 carefully prepared long-term projections shown in Table 4 below.

[30] Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

Table 4
GDP Growth Rates

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates					
Component	**Real Rate**	**TIPS Inflation Forecast**	**Nominal Rate**	**Weight**	**Weighted Rate**
EIA 2014 Placeholder	*2.40%*	**2.12%**	*4.57%*	16.70%	0.76%
OMB - White House 2016 Budget			**4.30%**	16.70%	0.72%
CBO			**4.20%**	16.70%	0.70%
Historical 1980 – 2014	**2.87%**	**2.12%**	5.05%	50.0%	2.53%
Composite				100%	**4.71%**
Historical 1980 – 2014 Q4			5.05%	100.0%	**5.05%**
Indiana U – Kelley 2018-35 Ctr Econometric Research	**2.90%**	**2.12%**	5.08%	100.0%	**5.08%**
Blue Chip* – Top 10% 2019 Values	**2.90%**	**2.12%**	5.08%	100.0%	**5.08%**
Blue Chip – Average	**2.40%**	**2.12%**	4.57%	100.0%	**4.57%**
Blue Chip – Bottom 10%	**1.90%**	**2.12%**	4.06%	100.0%	**4.06%**

Q. You recommend relying on meticulously prepared long-term growth rates from referent sources published last spring over possibly fresher, lower consensus-growth rates from this quarter. Why is that?

A. On leaving office, former FED Chairman Ben Bernanke advised analysts to be “cautious in their forecasts.” Taking that advice to heart, I recommend that the Commission treat Staff’s modeling results as a ceiling meriting reasonable confidence. This avoids the possibility that lower interim, consensus survey projections might suffer from downward bias due to recent successive global market shocks.

Q. Table 4-B of Docket No. UE 294 Opening Testimony Staff/200, Muldoon/22 showed substantial declines in GDP growth projections this spring from a year ago. Are you suggesting that the Commission consider these spring growth projections as one of several sets of reasonably-sourced growth rates while declining to use lower snapshots of growth expectations from this more volatile quarter?

A. Yes. Though long-term growth inputs appear to be eroding further, some of these projections are the result of surveys that may lack the same analytic rigor as the annual federal projections.

Q. Does this approach capture a reasonable set of investor expectations similar to Staff's analysis in other recent general rate cases?

A. Yes, Staff modeling captures the expectations of investors who think variously: A) that future conditions will mirror the past, B) that federal agency expert analysis informs the historical track record, and C) that the most optimistic 10 percent of Blue Chip referent persons surveyed have the pulse of the future.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for gas utilities?

A. Yes. In each of the Company's prior rate cases, Staff has shared plots of U.S. gas demand growth since 1950 on a 3-year moving average. This downward trending consumption curve allows GDP growth to be a conservative proxy for both gas sales and dividend growth rates.

Q. Can relying on a long-term GDP growth overstate required ROE?

A. Yes. It is possible that my modeling overstates required ROE for this reason.

Q. What are the results of your multistage DCF models?

A. Please see Exhibit Staff/203 for a summary followed by modeling detail.

Q. How do these estimated ROE values compare with gas utilities' ROE values for 2015 General Rate Cases?

A. These estimated ROEs are low compared with regulated U.S. utilities' authorized return on equity capital in 2015 as reported by SNL Financial, that range from a low ROE of 9.0 percent in New York for Central Hudson Gas and Electric to a high of 10.9 percent for Columbia Gas of Virginia, Inc. The Company's rate cases in each of the last two years provide greater detail.

Q. Why do you address equity flotation costs when Avista is participating in stock buybacks of late, and not floating new public stock offerings?[31]

A. My 12.5 bps upward adjustment is a durable modifier reflecting aggregate overall long-term cost to float new equity into perpetuity.

Q. Avista witness McKenzie asks for 10 bps adjustment for equity flotation costs and provides citations to references that would justify less consideration.[32] Why is Staff making a higher adjustment?

A. Staff's recommendation is based on Staff's own review restricted to actual costs of Commission jurisdictional energy utilities. Staff recommends this

31 Please see Avista/200, Thies/7-8 for a description of Avista's common stock buybacks.

32 See Avista/300, McKenzie/53.

12.5 bps upward adjustment for flotation costs for all six Oregon energy IOUs on an ongoing basis.

Q. What is your assessment of Mr. McKenzie's DCF analysis and results?

A. Mr. McKenzie's single state DCF modeling has not been found to be reliable by the Commission in the past. Staff recommends the Commission use the more realistic expectations in Staff's modeling.

Q. Did your analysis include the construction of a synthetic forward curve using UST TIPS break even points?

A. Yes. My forward curve is provided in Exhibit Staff/204, reflecting implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Q. Assume one ignored current downward adjustments by a broad spectrum of federal agencies and instead presumed that future U.S. GDP growth would look like the past 30 years. Would a ROE based on that assumption fall within Staff's recommended range?

A. Yes, I extracted and ran regression on data from U.S. BEA to generate the annual real historical GDP growth rate shown in Table 4. My recommended range of ROEs includes values that presume GDP growth over the next thirty years would look like that of the past 30 years.

Q. Do you show this analysis in your exhibits?

A. Yes. Exhibit Staff/205 shows my analysis in support of this finding.

Q. If utilities' dividends and EPS are growing at a faster rate than growth for the whole economy, then utilities would become a bigger part of the economy. Is that happening?

A. No. Gas utilities are not becoming a larger and larger part of the US economy.[33]

Q. What do you recommend to the Commission regarding Mr. McKenzie's results from his constant growth DCF model?

A. Mr. McKenzie's constant growth DCF model offers little to inform the Commission in this case.[34] I recommend the Commission give little weight to the results of Mr. McKenzie's model.

Q. How do your methods employed in this case differ from those utilized by Staff in Avista's prior two general rate cases, and in the recent Northwest Natural Gas Company rate case, UG 221?

A. My methods and modeling are very similar to those employed by Staff in recent general rate cases, including UG 221.

ALTERNATIVE MODELS EXAMINED

Q. What control modeling did you perform to corroborate your DCF results?

A. I examined several alternative models that support my DCF modeling. While I do not recommend that any alternate approach should replace the

33 *See* UE 283 Staff/200, Muldoon/17-22.

34 For example, the Commission rejected consideration of parties' constant growth DCF models in Docket No. UE 115.

Commission's reliance on three-stage DCF modeling, such alternate models may offer a check on the reasonableness of my recommendation.

SINGLE-STAGE GORDON GROWTH DCF MODELING

Q. Did you first examine the Company's constant Gordon growth DCF model?

A. Yes. However, I note that Brealey, Myers and Allen, in the tenth edition of their textbook "Principles of Corporate Finance" caution that "the simple constant-growth DCF formula is an extremely useful rule of thumb, but no more than that."[35]

Q. Do you view this model as simply an extremely imprecise vector pointing closer to 10 percent ROE than five percent ROE?

A. Yes. As calculated by Avista, this vector would point toward the top end of my three-stage DCF results when considering a point ROE from among a reasonable range of ROEs.

Q. Avista/300, McKenzie/37 explains how and why DCF results that are low should be eliminated, leaving high plausible results to dominate modeling recommendations. Is this reasonable?

A. Not entirely. This is something like raising a "wet finger in the wind." It can give you a direction vector but has a great deal of trouble measuring accurate wind speed. However, if one adjusts growth to best federal annual estimates

[35] "Principles of Corporate Finance", Brealey, Myers, and Allen, p 83 (10th Edition 2010).

and removes as many top outliers as low outliers, Mr. McKenzie's results are then consistent with my three-stage DCF modeling results.

Q. Why are you uncomfortable relying too much on this simple Gordon growth model applied variously to gas utilities, electric utilities and non-utility companies such as those that make jams and jellies?[36]

A. Gordon Growth single-stage DCF modeling makes the academic assumption that information about all future returns is contained in just a few values: namely the last dividend and an appropriate very long-term average growth rate.

Q. Why is this not plausible in the real world?

A. Were Gordon Growth even somewhat accurate, success in investing would be assured and there would be less need for the omnipresent investment disclaimer, "Past Performance is No Guarantee of Future Results." Staff recommends the Commission continue to assign little or no weight to Gordon Growth modeling and to be very skeptical of findings that average such weak extrapolations equally with results from much higher confidence modeling.

Q. Does Mr. McKenzie's single-state Gordon Growth model become more predictive of Gas Utility required ROEs when used to analyze non-utility stocks?

A. Theoretically, absent better information, one would consider all possible alternative investments that an investor, institution, company or fund might make compared to investing in a gas utility, such as investing in artwork or

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36 See Avista/301, Schedule AMM-13, page 2 of 3.

jam production. Fortunately, we find ourselves in possession of both substantial vetted information and more predictive models.

RISK PREMIUM MODELING

Q. Did you examine Mr. McKenzie's risk premium modeling?

A. Yes, however risk premium modeling is not a terribly reliable methodology.

Q. Do risk premium models track well through periods of time when FED policy is a key driver of ultra-low interest rates and when markets are dysfunctional as shown in the 2009 spikes in spreads over UST examined by Moody's in Staff/210, Muldoon/2?

A. No. Historical spreads over UST and the historical spreads between stocks and bonds can be poor predictors of FED policy. A risk premium review can be a fairly good check on an investor's own comfort level before executing an investment decision, provided the investor can say, "The stocks in this sector for a given credit rating track the bonds in this sector like so, and I have good reason to believe they will continue to do so in the future." If the investor ceases to have confidence in that statement, then the risk premium ceases to be a good validity check for a more complex model.

Q. When conflating stock and bond returns, is it obvious to investors whether the FED-driven low-interest-rate paradigm is different from pre-2008 patterns and durable into the future?

A. No.

Q. Is it clear whether exceedingly high spreads in 2008 and 2009 should be entirely eliminated or are in some way predictive of the future?

A. No. If one includes spreads that dwarf current conditions, one is effectively projecting another financial crisis.

Q. Are UST rate trends necessarily now a representative snapshot of where fixed income rates are heading?

A. No. John Lonski, Chief Economist of Moody's Capital Markets Research, Inc. in Credit Markets Review and Outlook released March 21, 2015, called the current state of business activity "mediocre."[37] His assessment is that the recent jump by Treasury yields may have overstated any rise of inflation risk, and that there are no "observable facts" behind it. If he is right, UST prices will rise and yields fall once again, absent news recommending otherwise. So despite the FED's and other predictions of where interest rates will be in the future, one finds that each of the major predictions of five-year interest rate trends made near calendar year end of each the last four years were wrong.

Q. Is there good reason to believe that Avista's examination of historical fixed income data is not predictive of the future – not even to describe conditions in 2016 at the end of the test year?

A. Yes. The FED is considering whether the financial crisis and Great Recession permanently slowed the U.S. economy's growth potential, thereby lowering

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[37] Staff accessed Moody's reporting on May 22, 2015 at https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_181342

the point at which the FED's benchmark interest rate should be considered neutral. April FED policy minutes released May 20, 2015, defined this "equilibrium rate" as the level of the FED funds rate, adjusted for inflation, consistent with the economy achieving, over a specified time horizon, maximum employment and price stability.[38]

Q. Are you implying that FED management of rates might not match an extrapolation of prior fixed income activity?

A. Yes, extrapolating historical data would have difficulty predicting trillion-dollar quantitative easing stimulus in the US, European Union and Japan. How the FED defines its target states can impact the timing and nature of FED actions which may overwhelm historic fixed income against common equities comparison trends.

Q. Please discuss the Ibbotson approach you used.

A. The Research Foundation of CFA Institute, an impartial non-profit organization, published "Rethinking the Equity Risk Premium" in 2011. Here, Professor Roger Ibbotson of the Yale School of Management, and other earlier examiners of how best to approach and calculate equity risk premiums, share their current thinking and findings.

"In the 85 years covered by the Ibbotson data, stocks delivered a real return of 6.6% against 2.1% for bonds, supporting a 4.5% equity risk

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38 Staff accessed the WSJ article, "A New, Lower Normal for FED Rates? FED Officials' Lively Debate" by Pedro Nicolaci da Costa on May 22, 2015, at www.WSJ.com.

premium."[39] Adding that 4.5 percent to about a potential 4.00 percent UST risk free rate for end of 2016, would suggest that an investor looking just for a quick rough estimate should demand about an 8.5 percent ROE to be satisfied to own a stock of average risk at year end 2016.

REBUTTAL OF AVISTA'S CAPM MODELING

Q. Did you examine and make adjustments to Avista's CAPM modeling?

A. Yes. The Company generates both a variant of traditional CAPM and ECAPM. As I see no investor or fund management firm using ECAPM, I suggest the Commission afford ECAPM no weight whatsoever. For CAPM, I note that the Company relies on an overly-high market risk premium.

I calculate expected returns using both Value Line and Yahoo Finance Betas which employ different indices, sampling methods and assumptions about mean reversion. Relying on an Ibbotson market risk premium of 4.50 percent, I see a range of expected return of 6.37 percent to 9.33 percent. These values are markedly lower than the expected returns of Mr. McKenzie.

Q. What do you conclude regarding the direction CAPM offers?

A. The Company appears to ignore the low end of industry practice using CAPM. Avista also relies on a high market risk premium. When Staff's typical finance approach is added to Avista's CAPM work, the result is a lower return on capital midpoint.

[39] "Rethinking the Equity Risk Premium," Research Foundation of CFA Institute p 81 (2011).

Q. What are Staff's intermediate CAPM findings?

A. Staff's modeling generates a midpoint 7.85 percent and a top 9.33 percent return on peer equity in my pre-tax CAPM results considering both 10- and 30-year UST as risk free rates, and considering both VL and Yahoo Finance Betas.

Q. Understanding that both Staff and the Commission have placed minimal weight on CAPM modeling results and that Staff only discuses Company results as a check in due diligence on Staff findings, what is the implication of CAPM expected returns on risky assets?

A. William Forsyth Sharpe, Professor of Economics at Stanford and one of winners of the 1990 Nobel Memorial Prize in Economic Sciences for the CAPM suggests that the expected return on a portfolio of stocks, as estimated by CAPM, should approximate the peer securities' cost of capital.

In the context of this rate case, CAPM can be interpreted as a downward pointing vector suggesting that one can reasonably look at less than the upper end of Staff's three-stage DCF modeling results. Exhibit Staff/206 shows a typical CAPM model for Avista stock inclusive of common variations.

Q. What is the formula used in this CAPM modeling?

A. The formula follows in Figure 5.

Figure 5 – CAPM Formula

$$\bar{r}_a = r_f + \beta_a (\bar{r}_m - r_f)$$

Where :

r_f = Risk free rate

β_a = Beta of the security

$\bar{r}_m$ = Expected market return

$(\bar{r}_m - r_f)$ = Equity market premium

Q. Avista's current Rate of Return (ROR) is 7.516. Do lower CAPM results, while holding Avista's Cost of LT Debt at Company requested levels in this rate case, suggest that Avista's required ROE could be lower?

A. Yes, CAPM modeling contains more information than Gordon Growth estimations and does suggest that Avista's required ROE should be lower than currently authorized. However, I recommend that the Commission put little weight on this methodology.

Q. What is the contribution of your CAPM review?

A. Though the Commission does not favor CAPM, I conducted this review considering that the Commission could alter its policy going forward.

Q. Are you saying that persons who manage money at risk gain little new information from a typically calculated CAPM, other than a downward vector recommending use of the midpoint or lower in your other modeling?

A. Yes. I merely show how CAPM is usually calculated in comparison with the calculations Avista has prepared for the Commission's consideration. And given the low-pointing vector, the Commission may want to consider a lower point ROE than the highest modeling result in my range of reasonable ROEs.

AVISTA'S COMPARATIVE RISKINESS

Q. Is Avista as a regulated utility less risky than the average publicly traded U.S. stock?

A. Yes. Avista is unique among Staff's peers, as the peer group has been compiled by Staff for purposes of determining an appropriate ROE. Only one other regulated gas utility has filed three consecutive general rate cases in the last decade. Avista has in comparison reduced regulatory lag in cost recovery, further reducing its risk compared to its peer gas utilities.

Q. Do Avista's frequent rate filings impact ratepayer perception regarding its risks and attractiveness of investment opportunity?

A. Prompt cost recovery and regulatory certainty has allowed Avista to depict the Company as a solid opportunity for investors seeking five percent to six percent rate base growth. As discussed earlier, the Company states in its June 2015 communication to investors that the Company is well positioned for the future. Staff finds that these characteristics also afford the Company access to historically low-cost capital.

Q. What do these rough alternative modeling methods, which are regularly used by investors for ballpark calculations, indicate?

A. Investors applying the simple constant-growth DCF formula see a recommendation of the top end of Staff's range of reasonable ROEs. Investors applying Ibbotson equity premium thinking or traditional CAPM modeling see a recommendation at the lower end of Staff's range of reasonable ROEs.

Q. How could investors check the reasonableness of modeling results?

A. Without consideration of below average risk due to multiple-year consecutive rate cases, investors applying the full spectrum of supported growth rates ranging from a composite (relying on historical experience and federal projections) to most optimistic Top 10 Blue Chip from Avista's last general rate case in my three-stage DCF models would generate ROEs ranging from 8.03 percent to 9.45 percent. Finding my peers to be a better fit for Avista's profile than the Company's peers, investors could narrow expectations to Staff's 8.76 percent to 9.45 percent reasonable range of ROEs with a recommended midpoint of 9.11 percent ROE. Table 5 below summarizes my modeling results.

Table 5
Results of Staff's Modeling
(See Exhibit Staff/203 for more detail)

Best Fit Range of Reasonable ROEs	**8.76%**	**to**	**9.45%**	**ROE**
(Best fit is Staff's Hamada adjusted screened gas utilities that have simial characteristics to AVA Regulated Gas Operations)				
Midpoint of Best Fit Modeling Results		**9.11%**	**ROE**	
(Staff's informed judgement excludes some of the lower range of modeling results depicted above)				

Q. Referring to Table 6 below, please explain why a 9.11 percent midpoint is a reasonable point ROE?

A. The Commission's authorized ROE in Avista's last general rate case is a sound starting point for a check of reasonableness of my recommendations. The first adjustment to last general rate case results is to reduce the cost of equity for changes in growth expectations. The lowering of growth expectations reduces the cost of equity by 31 basis points yielding an ROE of 9.19 percent. The next adjustment is to reflect the reduction in risk associated with frequent general rate case filings. Avista's very frequent rate cases and tracking mechanisms for prompt cost recovery of new facilities in my reasoned judgement merit a further drop of up to about 20 basis points. This provides a range of 9.00 to 9.19 percent. My recommended point ROE value of 9.11 percent falls solidly within that range of reasonable ROEs, as shown below in Table 6.

Table 6
Check for Reasonableness of Staff's Point ROE

Check of Reasonableness:				
Last Commission Authorized ROE:		**9.50%**		
Change in Long-Term GDP Growth		**9.19%**	(less 31 bps)	
Reduction in risk from frequent rate cases,	**9.00%**	**to**	**9.19%**	
and prompt cost recovery for new facilities.				
Staff Point ROE Recommendation:		**9.11%**	**ROE**	
* Staff Blue Chip Data is sourced from Table 1 Blue Chip Economic Forecast, Feb. 2015				
Note: This analysis does not reflect further downward correction by the CBO on Aug. 25, 2015				
For example Staff's modeling of 2015 GDP growth is not reduced from 2.9% to 2.0%				
See "CBO Cuts US 2015 GPD Forecast to 2% from 2.9%" by Nick Timiraos – WSJ – Aug. 25, 2015				

ADJUSTMENT OF MODELING RESULTS

Q. What sets Avista apart from the risks of its own proxy group as you have assembled?

A. Avista has filed three rate cases in the past three years. Given the Company's relatively low growth rate, capacity to file a rate case each year, and less need to plan for long term, Avista has become less risky than its peer utilities. The Maryland commission finds that similar factors reduce risk and regulatory lag in the current environment, meriting a lower point ROE from within a reasonable range of ROEs.[40] Avista is therefore not subject to much regulatory lag and is demonstrating better ability to manage risk than the Company's peers.

Q. In Order No. 09-020, the Commission concluded that the adoption of decoupling justified a ROE reduction of 10 bps. Do you recommend a similar outboard reduction in ROE for Avista now?

A. No. I recommend the Commission consider a lower than top ROE from within the range of reasonable ROEs in my modeling reflective of the lower risk profile Avista has achieved by effectively managing regulatory lag.

Q. Are you opposed to regulatory certainty for Avista?

A. No. I merely note that Avista has successfully managed regulatory risk suggesting that Avista Corporation is operating within a supportive regulatory environment. I do not see this as a negative, because this finding is supportive of the Company's credit ratings.

HAMADA EQUATION

Q. Your application of the Hamada Equation to un-lever peer utility capital structures and to re-lever at Avista's target capital structure increases required ROE by 18 bps. Why is this adjustment reasonable?

A. I usually employ the Hamada Equation as a check on the reasonableness of my modeling results. As earlier discussed, my screening criteria already

[40] *See* Public Service Commission of Maryland, Order No. 85374, Case No. 9299, at 78 – February 22, 2013, accessible at: http://webapp.psc.state.md.us/Intranet/Casenum/CaseForm_new.cfm

identify peers that have a very close capital structure to Avista's. Use of the Hamada adjusted results helps ensure that I have captured all material risk in my analysis.

Q. In addition to your 65 standard data requests and 25 multiple-part follow up data requests, did you also rely on other Company information?

A. Yes. I relied on some inputs that the Company provided by phone and email, which were followed up with additional data requests, that are not yet returned as of the compiling of this testimony.

INFORMED STAFF ANALYSIS

Q. Did you take into account information from other models?

A. Yes. I performed a constant-growth DCF model analysis using the Company's inputs and methods and performed a rough equity risk premium analysis relying on an approach discussed by Professor Roger Ibbotson of the Yale School of Management in *Rethinking the Equity Risk Premium.*[41] I also showed how CAPM as typically calculated suggests my three-stage DCF modeling is reasonable and well considered.

Q. Do you monitor and analyze current and projected market conditions?

A. Yes. My analysis includes analysis of the current economic climate and its impact on my estimates of long-term growth. I also rely heavily on feeds from SNL Financial LC (SNL), Bloomberg, Moody's, S&P, WSJ and other sources to

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[41] Staff/200, Muldoon/24-25.

make sure that my financial understandings are reflective of investor expectations. Please see a cross section of recent news in Exhibit Staff /210.

Q. Did you develop your recommendations while informed by authorized ROEs in other parts of the country?

A. Yes. I examined recently authorized ROEs across the nation. Please see Exhibit Staff/212 for SNL's midyear utility rate case ROE trends.

Q. Did you use robust and proven analytical methodologies?

A. Yes. My methods are similar to Staff's work over the last decade.

Q. Briefly recap changes in estimates of long-term growth in GDP since the last Avista general rate case.

A. From 2008 through Avista's last general rate case, referent economists, government agencies, university business schools, and business leaders expressed at least some expectation on average that American worker populations, productivity and aggregate output would return to pre-recession trends. Over the last year the broad consensus was that America has challenging fundamental problems in sustaining historic GPD growth.

Q. As the growth rate is pivotal in this case, please describe what long-term growth rates you relied on.

A. The lowest estimate of long-term GDP growth, 4.71 percent, is a weighted average of historic GDP and forecasts from three federal sources. 50 percent weight is applied to the aggregate estimates of long-term GDP by the EIA, the OMB, and the CBO, with each federal source receiving one-third of the 50 percent weight. The remaining 50 percent is the average annual historical real

GDP growth rate, established with a regression analysis, for the period 1980 through 2014, to which I applied the TIPs inflation forecast.

Q. What is your second growth rate?

A. My second long-term growth rate 5.05 percent captures historical growth.

Q. What is your third growth rate?

A. My third growth rate, 5.08 percent, is the current Indiana/Blue Chip Top 10 growth projection through 2019. This reflects the growth that 9 of 10 referent and informed current Blue Chip survey responders would find higher than they could support. It also matches the modeling input cited by Indiana University's Kelley School of Business. This value may be seen as the highest current expectation of forward GDP rates for financial modeling purposes.

Q. How are the three growth rates used in your analysis?

A. Using the cohort of proxy companies that met my screens, I ran each of its two DCF models three times, each time using a different long-term growth rate.

Q. How did you evaluate the Company's peer cohort and other tests?

A. After performing these initial runs, I performed sensitivity analysis.

Q. How did you test the impact of Avista's peer company selection?

A. I ran each of its models using Avista's cohort of gas proxy group, again using the three different long-term growth rates for the third stage of growth as discussed above.

Q. How did you adjust for capital structures divergent to Avista's?

A. I used the Hamada equation to de-lever or remove debt from the proxy companies and then to re-lever or add debt to match Avista's 50 percent equity target capital structure in this rate case.

Q. What other adjustment did you make in this case?

A. I made an upward adjustment of 12.5 basis points to account for the cost of Avista's equity flotation inclusive of a portion of interest carrying cost for an equity forward provision.

Q. Does your range of reasonable ROEs encompass the entirety of these modeling results including the results for each peer group and sensitivity examined?

A. Yes. The lower end of my range of reasonable ROEs is most impacted by my composite growth rate, which is informed by federal forecasts of GDP growth as compared to like projections from the same agencies a year ago.

Q. Is the upper end of your range of reasonable ROEs driven by results from the Company's peer group utilizing the top growth rate?

A. Interestingly no. My upper range of reasonable ROEs is from my peer group utilizing the highest growth rate adjusted for capital structure divergent from Avista's.

Q. Does your recommendation include results from the Company's peer group?

A. Yes, it does, but because the Company's peer group did not produce the highest modeling results, my range of reasonable ROEs brackets the results for the Company's peer group. If I were to rely on the Company's gas peer group, my upper limit in my range of recommended ROEs would be lower.

UPDATES TO AVISTA MODELS

Q. As you discussed earlier, currently Staff has the freshest data in its modeling along with more current long-term projections. Should the Commission see dated inputs as technical deficiencies?

A. No, the Staff data is fairly recent and can be relied upon to produce reasonable results.

Q. Does Staff's screening eliminate companies that are not like Avista?

A. Yes. The point of screening is to identify a small group of companies with very similar characteristics to Avista that can act as a close proxy for Avista. By modeling and examining the proxy group, investors may project information not directly observable from Avista. As the peer group grows, information is diluted by information from companies that no longer resemble Avista closely.

ISSUE 3 – COST OF LT DEBT

Q. Have you compiled a summary table illustrating your calculation of Avista's Cost of LT Debt?

A. Yes, please see confidential Exhibit Staff/207.

Q. Is this table updated to reflect Avista's 2015 planned debt issuance(s)?

A. Yes. This table remains confidential until the Company informs the public of issuance detail.

Q. How do you recommend the Commission address planned 2015 bond issuances and 2016 debt in general?

A. I recommend the Commission utilize actual debt issuance information for 2015 and my pro forma projections for 2016.

Q. Did you prepare a debt maturity profile for Avista?

A. Yes. It is provided in Staff/207, Muldoon/3.

Q. Need the Commission wait for any updates to resolve Cost of LT Debt?

A. No, the Commission can review my confidential LT Debt table, and debt maturity profile in Exhibit Staff/207 and the maturities of the Company's issuances over the last five years. This material provides the information for the Commission to make an informed decision regarding Cost of LT Debt, without having to wait for more detail about 2015 planned issuances.

Q. To review, do you recommend 5.515 percent cost of LT Debt for Avista, reflective of all updates by the Company and market movements since its filing in this rate case?

A. Yes. My recommendation recognizes that investment banks have priced in uncertainties in the form of higher spreads over UST than were present in the bond markets a year ago. However, my analysis is based on Bloomberg monthly average forward curves for times of planned issuances and may overstate future issuance costs if falling UST yields reported October 2, 2015 continue.

CONCLUSION

Q. What is your recommendation regarding ROE?

A. I recommend that the Commission consider a range of reasonable ROEs from 8.76 percent to 9.45 percent, and a point ROE of 9.11 percent. This is the midpoint in my range of reasonable ROEs.

Q. How do you conclude your testimony?

A. Avista common stock and bond offerings remain attractive to institutional and to conservative investors who rely on stable growing dividends to meet their obligations in turn. Due to predictable dividend growth into the future, Avista stock has recently also been an excellent alternative to investing in currently low yielding UST. And given recent global volatility and uncertainty, the Company's stocks and bonds continue to be an appealing safe haven for investors.

Q. Are Avista's stock and bond offerings largely insulated from many global uncertainties and also from recent offering reductions and withdrawals in debt markets?

A: Yes. Investment banks and debt markets have become skittish on debt for uncertain purposes such as to build shopping centers and to expand mining operations. This only increases the appeal of Avista's securities as a safe harbor for investors to ride out global uncertainties.[42]

Q. Why do you recommend the Commission consider a lower point ROE than the uppermost ROE resultant from your modeling?

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[42] See "Debt Market Tumult Hits Corporate Bond Sales" by Mike Cherney in the WSJ of September 28, 2015.

A: There are two key reasons: First, this is Avista's third consecutive annual general rate case, complete with methods for rapid cost recovery and income certainty. Avista's management has controlled risk and regulatory lag well. Avista is now less risky than its peers. Only one other U.S. gas utility filed general rate cases with Avista's frequency in the last decade.

Q. What is the second reason?

A: Since Avista's last general rate case, there has developed a broad consensus that U.S. GDP will not return to pre-recession trends. My modeling inputs are anchored in part in projections from referent sources this past spring. Even lower consensus growth projections since then may be accurate. But I feel that the annual numbers from this past spring are carefully compiled by federal government experts and other sources. Current lower spot growth estimates may be overshooting downward and may be subject to correction by the time annual projections are again prepared for 2016.

Q. Do you expect a lower authorized ROE to hurt Avista's credit profile?

A: No, Moody's Investors Service on March 1, 2015 examined this subject in its publication, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles."

Q. What are the key drivers underlying Moody's findings?

A: Moody's review, provided as Exhibit Staff/210, noted three key factors:

1. More Timely Cost Recovery Helps Offset Falling ROEs;
2. Utilities' Cash Flow is Somewhat Insulated from Lower ROEs; and
3. Utilities' Actual Financial Performance Remains Stable.

Q. Investor behavior such as that described in Staff/210, Muldoon/5 appears to anticipate lower inflation than the FED projects. Is there a risk that your use of quarterly FED data overstates required ROE?

A: That is a reasonable concern. However, reliance on vetted quarterly inputs avoids overreliance on spot information that may be driven downward in part by successive recent market surprises and shocks.

Q. Does that conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

October 16, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew J. Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Economist Utility Program Energy – Rates Finance and Audit Division
ADDRESS:	201 High Street, Suite 100 Salem, OR 97301-3612.
EDUCATION:	In 1981, I received a Bachelors of Arts Degree in Political Science from the University of Chicago. In 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis with an emphasis on Cost of Capital. I have worked on Cost of Capital in the following general rate case dockets: AVA UG 186; UG 201, UG 246, and UG 284 current; NWN UG 221; PAC UE 246, and UE 263; PGE UE 262, UE 283, and UE 294 current. From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

Abbreviations: AVA – Avista Corp., CNG – Cascade Natural Gas Company, IPC – Idaho Power Company, NWN – Northwest Natural Gas Company, PAC – PacifiCorp, PGE – Portland General Electric Company

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Staff Peer Screening

Exhibits in Support
of Opening Testimony

October 16, 2015

Acronyms and Abbreviations Used

CIK	SEC Central Index Key
EDGAR	SEC Electronic Data Gathering, Analysis and Retrieval System
EEI	Edison Electric Institute
EIN	IRS Employer Identification Number
IRS	U.S. Internal Revenue Service
SEC	U.S. Securities and Exchange Commission
SIC	Standard Industrial Code
SNL	SNL Financial, LC – A financial Information gathering firm
U.S.	United States of America
VL	Value Line Investment Survey, The

Moody's		S&P		Fitch		DBRS		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	AAA	R-1H	High Grade
Aa1		AA+		AA+		AA(high)		High grade
Aa2		AA		AA		AA	R-1M	
Aa3		AA-		AA-		AA(low)		
A1		A+	A-1	A+	F1	A(high)	R-1L	Upper medium grade
A2		A		A		A		
A3	P-2	A-	A-2	A-	F2	A(low)		
Baa1		BBB+		BBB+		BBB(high)	R-2H	Lower medium grade
Baa2	P-3	BBB	A-3	BBB	F3	BBB	R-2M	
Baa3		BBB-		BBB-		BBB(low)	R-2L, R-3	
Ba1	Not prime	BB+	B	BB+	B	BB(high)	R-4	Non-investment grade speculative
Ba2		BB		BB		BB		
Ba3		BB-		BB-		BB(low)		
B1		B+		B+		B(high)		Highly speculative
B2		B		B		B	R-5	
B3		B-		B-		B(low)		
Caa1		CCC+				CCC(high)		Substantial risks
Caa2		CCC				CCC		
Caa3		CCC-				CCC(low)		
						CC(high)		
		CC	C	CCC	C	CC		

Source: http://en.wikipedia.org/wiki/Credit_rating

Utility Continuity Screen

Natural Gas
AVA UG 288

1 Sensitivity with AWK, CWT, MSEX, & YORW
2 Sensitivity with AGL

Note: All VL Diversified Gas Co.'s Eliminated due to M&A Activity

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	VL Corporate Name Gas Utility	NYS, NSDQ Ticker	SNL Key	IRS EIN	SEC File	VL Region	VL 8/7/2015 Beta	VL 8/7/2015 Timliness	VL 8/7/2015 Safety	VL 8/7/2015 Technical	Yahoo Fin. 8/6/2015 Beta	Yahoo Fin. 8/6/2015 Mkt Cap $ Billions	VL 8/7/2015 Mkt Cap $ Billions	Gas or Water U. w VL Beta < 1 8/7/205	VL ID No.	SNL or VL No Div Declines 5 years	Either / Or: S&P Local LT 8/10/2015 Rating ≥ BBB-	Either / Or: Moody's Local LT 8/10/2015 Rating ≥ Baa3	2014 10-K ≥ 80% U.S. Regulated Revenues
-	Avista	No	No	Avista Corporation (*For reference Purposes Only*)	AVA	4057075	91-0462470	1-3701	West	0.80	2	2	2	0.62	2.02	1.45919	-	9677	Pass	BBB	Baa2	92%
-	Cascade	No	No	Cascade Natural Gas Corp.	MDU	4057112	91-0599090	1-7196	West	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	Pass	BBB+	none	100%
1	AGL	Yes	Sensitivity	AGL Resources, Inc.	GAS	4057108	58-2210952	1-14174	East	0.80	3	1	5	0.28	5.76	5.90	Yes	785	Pass	BBB+	W Jan 2015	*
2	Atmos	Yes	No	Atmos Energy Corp.	ATO	4057157	75-1743247	1-10042	Central	0.85	2	1	4	0.66	5.54	5.40	Yes	802	Pass	A-	A2	59%
3	Laclede	Yes	No	The Laclede Group, Inc.	LG	4002506	74-2976504	1-16681	Central	0.70	3	2	4	0.54	2.32	2.30	Yes	5203	Pass	A-	Baa2	84%
4	New Jersey	Yes	No	New Jersey Resources Corp.	NJR	4057128	22-2376465	1-8359	East	0.80	3	1	4	0.92	2.43	2.60	Yes	6359	Pass	A	Aa2	25%
5	NiSource	Yes	No	NiSource Inc.	NI	4057051	35-2108964	1-16189	East	0.85	N/A	3	N/A	0.54	5.35	14.90	Yes	6188	Pass	BBB+	Ba1	50%
6	Northwest Natural	Yes	Yes	Northwest Natural Gas Company	NWN	4057132	93-0256722	1-15973	West	0.70	3	1	4	0.73	1.18	1.20	Yes	6490	Pass	A+	A3	96%
7	Piedmont	Yes	Yes	Piedmont Natural Gas Company, Inc.	PNY	4057136	56-0556998	1-6196	East	0.80	4	2	4	0.68	2.99	2.90	Yes	7094	Pass	A	A2	93%
8	South Jersey	Yes	No	South Jersey Industries, Inc.	SJI	4057145	22-1901645	1-6364	East	0.85	3	2	3	1.21	1.64	1.80	Yes	8281	Pass	BBB+	A2	61%
9	Southwest Gas	Yes	No	Southwest Gas Corporation	SWX	4041957	88-0085720	1-7850	West	0.85	2	3	5	0.88	2.54	2.50	Yes	8314	Pass	BBB+	A3	67%
10	UGI	No	No	UGI Corporation (Propane Focus / VL)	UGI	4057537	23-2668356	1-11071	East	0.95	2	2	4	0.79	6.03	6.30	Yes	9166	Pass	None	A2	13%
11	WGL	Yes	No	WGL Holdings, Inc.	WGL	4007261	52-2210912	1-16163	East	0.80	3	1	4	0.89	2.75	2.80	Yes	9668	Pass	A+	A3	49%
12	American States	No	No	American States Water Company	AWR	N/A	95-4676679	1-14431	Water	0.70	3	2	2	1.39	1.46	1.50	Yes	8288	Pass	A+	Withdrawn	73%
13	American Water	No	Sensitivity	American Water Works Company, Inc.	AWK	N/A	51-0063696	1-34028	Water	0.70	2	3	2	0.55	9.32	9.80	Yes	98442	Pass	A	A3	89%
14	Aqua America	No	No	Aqua America, Inc.	WTR	N/A	23-1702594	1-6659	Water	0.70	3	2	2	0.93	4.53	4.70	Yes	7056	Pass	None	A3	98%
15	CA Water	No	Sensitivity	California Water Service Group	CWT	N/A	77-0448994	1-13883	Water	0.75	3	3	2	1.27	1.02	1.20	Yes	1574	Pass	A+	Withdrawn	97%
16	CT Water	No	No	Connecticut Water Service, Inc.	CTWS	N/A	06-0739839	0-8084	Water	0.65	3	3	2	0.59	0.38	0.40	Yes	2274	Pass	A	Withdrawn	94%
17	Consol Water	No	No	Consolidated Water Co. Ltd.	CWCO	N/A	98-0619652	0-25248	Water	0.90	4	3	3	1.29	0.18	0.18	Yes	9991	Pass	None	Withdrawn	36%
18	Middlesex Water	No	Sensitivity	Middlesex Water Co.	MSEX	N/A	22-1114430	0-422	Water	0.75	3	2	2	0.60	0.37	0.38	Yes	5950	Pass	A-	Withdrawn	88%
19	SJW	No	No	SJW Corp.	SJW	N/A	77-0066628	1-8966	Water	0.80	4	3	2	0.73	0.68	0.63	Yes	7824	Pass	None	Withdrawn	96%
20	York Water	No	Sensitivity	York Water Company (The)	YORW	N/A	23-1242500	1-34245	Water	0.70	3	2	2	0.77	0.30	0.27	Yes	16182	Pass	A-	Withdrawn	100%
	TOTAL PEERS	11	2					Gas Utility	AVG:	0.81												
			7						STDV:	0.07												
			w Sensitivities					H_2O Utility	AVG:	0.74												
									STDV:	0.07												
										VL												

Utility Continuity Screen

Natural Gas
AVA UG 288

1 Sensitivity with
2 Sensitivity with
Note: All VL Diversifi

1 #	2 Abbreviated Utility	3 UG 288 AVA	4 UG 288 Staff	24 VL 2015 LT Debt < 56% of Capital	25 VL 2018-2020 LT Debt % of Capital	26 VL 2015 Common Equity % of Capital	27 VL Preferred Stock of Capital	28 VL Div. Growth Rate > 0%	29 No M&A Activity in Last 4 Years	30 Bloomberg M&A Under 11% of Mkt Cap	31 M&A Activity Activity in Last 5 Years	#
-	Avista	No	No	50.83%	53.97%	49.2%	0.0%	Pass	Pass	9%	2014 Purchase of AERC, parent of AK Electric Light and Power for $170 M & Sale of Ecova	-
-	Cascade	No	No	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
1	AGL	Yes	Sensitivity	48.0%	50.0%	52.0%	0.0%	Pass	Fail	Fail / Aug 2015	*Acquired Nicor Dec. 2011, Divested Compass Energy, Tropical Shipping. Southern Co to Buy / WSJ Aug. 2015	1
2	Atmos	Yes	No	44.5%	45.0%	55.5%	0.0%	Pass	Pass	7%		2
3	Laclede	Yes	No	54.0%	51.0%	46.0%	0.0%	Pass	Fail	125%	Acquired Missouri Gas 975M Sep 2013. Proposal to buy AL Gas – Pending	3
4	New Jersey	Yes	No	32.5%	27.5%	67.5%	0.0%	Pass	Pass	0%		4
5	NiSource	Yes	No	56.0%	56.0%	44.0%	0.0%	Pass	Fail	*	* Spinoff of Columbia Pipeline Group – Balance Sheet in Flux / VL. 2015,6 Ops will vary widely / VL & SNL	5
6	Northwest Natural	Yes	Yes	44.5%	44.0%	55.5%	0.0%	Pass	Pass	0%		6
7	Piedmont	Yes	Yes	48.0%	43.0%	52.0%	0.0%	Pass	Pass	N/A	Acquired Privatized Service to Fort Bragg, NC per Oct. 2013 agreement w US DOD per SNL	7
8	South Jersey	Yes	No	47.0%	47.0%	53.0%	0.0%	Pass	Pass	0%		8
9	Southwest Gas	Yes	No	49.0%	47.5%	51.0%	0.0%	Pass	Pass	0%		9
10	UGI	No	No	54.0%	46.0%	46.0%	0.0%	Pass	Fail	50%	Purchase of Heritage Propane Jan 2013 – Very Heavy Propane Position	10
11	WGL	Yes	No	32.5%	29.0%	66.0%	1.5%	Pass	Pass	0%		11
12	American States	No	No	41.0%	42.0%	59.0%	0.0%	Pass	Pass	0%		12
13	American Water	No	Sensitivity	53.5%	55.0%	46.4%	0.1%	Pass	Pass	N/A	Acquired Mt. Ebo Sewage	13
14	Aqua America	No	No	49.5%	50.0%	50.5%	0.0%	Pass	Fail	ACQ	16 Acquisions in 2014 – 300 Purchases in last 2 decades / VL.	14
15	CA Water	No	Sensitivity	43.0%	41.5%	57.0%	0.0%	Pass	Pass	0%		15
16	CT Water	No	No	45.5%	47.5%	54.4%	0.1%	Pass	Fail	ACQ	Purchased Maine Water in Jan 2012, and Purchase of Biddeford & Saco in Maine in Dec. 2012.	16
17	Consol Water	No	No	0.0%	0.0%	99.9%	0.1%	Pass	Pass	0%	Unclear Earnings Results for Foreign Operations beyond those serving San Diego and Tijuana / VL	17
18	Middlesex Water	No	Sensitivity	40.5%	43.5%	58.4%	1.1%	Pass	Pass	0%		18
19	SJW	No	No	52.5%	53.5%	47.5%	0.0%	Pass	Fail	ACQ	Acquired Bexar Metropolitan Water Dist. – Large 1-time 2014 profits.	19
20	York Water	No	Sensitivity	47.5%	48.0%	52.5%	0.0%	Pass	Pass	0%		20
	TOTAL PEERS	11	2 7 w Sensitivities									

Avista - Gas Peer Dividends

UG 288

Value Line Estimated Dividends (columns 28–30)

	1 #	2 Abbreviated Utility	3 UG 288 AVA	4 UG 288 Staff	5 Ticker	6 2010 Q1	7 2010 Q2	8 2010 Q3	9 2010 Q4	10 2010 Yr	11 2011 Q1	12 2011 Q2	13 2011 Q3	14 2011 Q4	15 2011 Yr	16 2012 Q1	17 2012 Q2	18 2012 Q3	19 2012 Q4	20 2012 Yr	21 2010-12 Average	22 2013 Q1	23 2013 Q2	24 2013 Q3	25 2013 Q4	26 2013 Yr	27 2011-13 Average	28 2014 Q1	29 2014 Q2	30 2014 Q3
1	1	AGL	Yes	Sensitivity	GAS	0.44	0.44	0.44	0.44	1.76	0.45	0.45	0.45	0.55	1.90	0.36	0.46	0.46	0.46	1.74	1.80	0.47	0.47	0.47	0.47	1.88	1.84	0.49	0.49	0.49
2	2	Atmos	Yes	No	ATO	0.335	0.335	0.335	0.34	1.35	0.34	0.34	0.34	0.345	1.37	0.345	0.345	0.345	0.35	1.39	1.37	0.35	0.35	0.35	0.37	1.42	1.39	0.37	0.37	0.37
3	3	Laclede	Yes	No	LG	0.395	0.395	0.395	0.395	1.58	0.405	0.405	0.405	0.405	1.62	0.415	0.415	0.415	0.415	1.66	1.62	0.425	0.425	0.425	0.425	1.70	1.66	0.44	0.44	0.44
4	4	New Jersey	Yes	No	NJR	0.34	0.34	0.34	0.34	1.36	0.18	0.18	0.18	0.18	0.72	0.19	0.19	0.19	0.40	0.97	1.02	0.00	0.20	0.20	0.20	0.6	0.76	0.21	0.21	0.21
5	5	NiSource	Yes	No	NI	0.23	0.23	0.23	0.23	0.92	0.23	0.23	0.23	0.23	0.92	0.23	0.23	0.24	0.24	0.94	0.93	0.24	0.24	0.25	0.25	0.98	0.95	0.25	0.25	0.26
6	6	Northwest Natural	Yes	Yes	NWN	0.415	0.415	0.415	0.435	1.68	0.435	0.435	0.435	0.445	1.75	0.445	0.445	0.445	0.455	1.79	1.74	0.455	0.455	0.455	0.46	1.83	1.79	0.46	0.46	0.46
7	7	Piedmont	Yes	Yes	PNY	0.27	0.28	0.28	0.28	1.11	0.28	0.29	0.29	0.29	1.15	0.29	0.30	0.30	0.60	1.49	1.25	0.00	0.31	0.31	0.31	0.93	1.19	0.31	0.32	0.32
8	8	South Jersey	Yes	No	SJI	0.00	0.165	0.165	0.348	0.68	0.00	0.183	0.183	0.3840	0.75	0.00	0.202	0.202	0.423	0.83	0.75	0.00	0.222	0.222	0.458	0.90	0.83	0.00	0.237	0.237
9	9	Southwest Gas	Yes	No	SWX	0.238	0.25	0.25	0.25	0.99	0.25	0.265	0.265	0.265	1.05	0.265	0.295	0.295	0.295	1.15	1.06	0.295	0.33	0.33	0.33	1.29	1.16	0.33	0.365	0.365
10	11	WGL	Yes	No	WGL	0.370	0.378	0.378	0.378	1.50	0.378	0.39	0.39	0.39	1.55	0.39	0.40	0.40	0.40	1.59	1.55	0.40	0.42	0.42	0.42	1.66	1.60	0.42	0.44	0.44
11	13	American Water	No	Sensitivity	AWK					0.86	0.22	0.23	0.23	0.23	0.91	0.23	0.23	0.25	0.50	1.21	0.99	0.00	0.28	0.28	0.28	0.84	0.99	0.28	0.31	0.31
12	15	CA Water	No	Sensitivity	CWT					0.60	0.154	0.154	0.154	0.15	0.62	0.1575	0.1575	0.1575	0.1575	0.63	0.62	0.16	0.16	0.16	0.16	0.64	0.63	0.1625	0.1625	0.1625
13	18	Middlesex Water	No	Sensitivity	MSEX					0.72	0.183	0.183	0.183	0.185	0.73	0.185	0.185	0.185	0.1875	0.74	0.73	0.1875	0.1875	0.1875	0.19	0.75	0.74	0.19	0.19	0.19
14	20	York Water	No	Sensitivity	YORW					0.52	0.131	0.131	0.131	0.131	0.52	0.134	0.134	0.134	0.134	0.54	0.53	0.14	0.1431	0.1431	0.1431	0.57	0.54	0.1431	0.1431	0.1431
		TOTAL	10	2 7 w Sensitivities																										

Note: Staff Halves Historic Values for NJR to Reflect 2/1 Split

Avista - Gas Peer EPS

Value Line Estimated EPS (from column 13)

	1 #	2 Abbreviated Utility	3 UG 288 AVA	4 UG 288 AVA	5 Ticker	6 2012 Q1	7 2012 Q2	8 2012 Q3	9 2012 Q4	10 2012 Yr	11 2013 Q1	12 2013 Q2	13 2013 Q3	14 2013 Q4	15 2013 Yr	16 2014 Q1	17 2014 Q2	18 2014 Q3	19 2014 Q4	20 2014 Yr	21 2012-14 Average	22 2015 Q1	23 2015 Q2	24 2015 Q3	25 2015 Q4	26 2015 Yr	27 2013-15 Average	28 2016 Q1	29 2016 Q2	30 2016 Q3
1	1	AGL	Yes	Sensitivity	GAS	1.12	0.28	0.08	0.84	2.32	1.31	0.41	0.24	0.68	2.64	2.81	0.48	0.19	1.24	4.72	3.23	1.62	0.30	0.20	0.98	3.10	3.49	1.75	0.35	0.25
2	2	Atmos	Yes	No	ATO	0.68	1.12	0.31	0.00	2.11	0.85	1.23	0.36	0.08	2.52	0.95	1.38	0.45	0.23	3.01	2.55	0.96	1.35	0.47	0.22	3.00	2.84	1.00	1.45	0.51
3	3	Laclede	Yes	No	LG	1.12	1.32	0.38	(0.03)	2.79	1.14	1.34	0.25	(0.30)	2.43	1.09	1.59	0.33	(0.35)	2.66	2.63	1.09	2.18	0.20	(0.32)	3.15	2.75	1.15	1.90	0.30
4	4	New Jersey	Yes	No	NJR	0.55	0.90	0.05	(0.14)	1.36	0.43	0.82	0.12	(0.01)	1.36	0.47	1.81	0.05	(0.23)	2.10	1.61	0.65	1.16	0.10	(0.16)	1.75	1.74	0.66	1.17	0.11
5	5	NiSource	Yes	No	NI	0.66	0.23	0.06	0.42	1.37	0.69	0.23	0.16	0.49	1.57	0.85	0.25	0.10	0.49	1.69	1.54	0.85	0.25	0.15	0.60	1.85	1.70	0.95	0.30	0.20
6	6	Northwest Natural	Yes	Yes	NWN	1.51	0.05	(0.39)	1.05	2.22	1.40	0.08	(0.31)	1.07	2.24	1.40	0.04	(0.32)	1.04	2.16	2.21	1.04	0.10	(0.30)	1.06	1.90	3.30	1.40	0.10	(0.30)
7	7	Piedmont	Yes	Yes	PNY	1.05	0.70	(0.06)	(0.03)	1.66	1.18	0.74	(0.03)	(0.11)	1.78	1.26	0.80	(0.09)	(0.13)	1.84	1.76	1.18	0.82	(0.05)	(0.10)	1.85	1.82	1.22	0.86	(0.02)
8	8	South Jersey	Yes	No	SJI	0.83	0.14	0.07	0.49	1.53	0.76	0.16	(0.02)	0.62	1.52	1.01	0.15	(0.05)	0.47	1.58	1.54	0.86	0.16	0.03	0.60	1.65	1.58	0.93	0.18	0.04
9	9	Southwest Gas	Yes	No	SWX	1.70	(0.08)	(0.09)	1.33	2.86	1.73	0.22	(0.06)	1.22	3.11	1.51	0.21	0.04	1.25	3.01	4.00	1.53	0.23	0.05	1.34	3.15	3.09	1.62	0.28	0.07
10	11	WGL	Yes	No	WGL	1.13	1.58	0.08	(0.11)	2.68	1.14	1.75	(0.03)	(0.55)	2.31	0.99	1.84	0.02	(0.17)	2.68	2.56	1.16	2.02	0.00	(0.28)	2.90	2.63	1.18	2.04	0.03
11	13	American Water	No	Sensitivity	AWK	0.28	0.66	0.87	0.30	2.11	0.32	0.57	0.84	0.33	2.06	0.39	0.62	0.86	0.52	2.39	2.19	0.45	0.70	1.00	0.45	2.60	2.35	0.50	0.75	1.05
12	15	CA Water	No	Sensitivity	CWT	0.03	0.31	0.56	0.12	1.02	0.01	0.28	0.61	0.12	1.02	(0.11)	0.36	0.7	0.24	1.19	1.08	0.00	0.32	0.73	0.15	1.20	1.14	0.00	0.31	0.74
13	18	Middlesex Water	No	Sensitivity	MSEX	0.11	0.23	0.38	0.17	0.89	0.20	0.28	0.36	0.19	1.03	0.2	0.29	0.42	0.22	1.13	1.02	0.21	0.31	0.43	0.20	1.15	1.10	0.22	0.32	0.45
14	20	York Water	No	Sensitivity	YORW	0.15	0.17	0.22	0.18	0.72	0.17	0.18	0.19	0.21	0.75	0.16	0.22	0.23	0.28	0.89	0.79	0.19	0.25	0.26	0.25	0.95	0.86	0.2	0.26	0.28
		TOTAL	10	2 7 w Sensitivities																										

Note: Staff Halves Historic Values for NJR to Reflect 2/1 Split

Historical and Near Term
VL Dividends, and
VL Earnings per Share

Avista - Gas Peer Dividends

	1	2	3	4	5	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46		
	#	UG 288 Abbreviated Utility	UG 288 AVA	UG 288 Staff	Ticker	nds 2014 Q4	2014 Yr	2012-14 Average	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2015 Yr	2013-15 Average	2016 Yr	2017 Yr	2018 Yr	2019 Yr	2020 Yr	VL Avg. 2018 - 20 / Yr	Div Growth 2018-20 vs. 2012-14	#	
1	1	AGL	Yes	Sensitivity	GAS	0.49	1.96	1.86	0.51	0.51	0.51	0.51	2.04	1.96	2.10	2.20	2.30	2.40	2.50	2.40	4.3%	1	1
2	2	Atmos	Yes	No	ATO	0.39	1.50	1.44	0.39	0.39	0.39	0.39	1.56	1.49	1.64	1.72	1.81	1.90	1.99	1.90	4.8%	2	2
3	3	Laclede	Yes	No	LG	0.44	1.76	1.71	0.46	0.46	0.46	0.46	1.84	1.77	1.92	2.01	2.10	2.20	2.30	2.20	4.3%	3	3
4	4	New Jersey	Yes	No	NJR	0.23	0.86	0.81	0.23	0.23	0.23	0.23	0.92	0.79	0.94	0.95	0.97	0.98	0.99	0.98	3.2%	4	4
5	5	NiSource	Yes	No	NI	0.26	1.02	0.98	0.26	0.26	0.26	0.28	1.06	1.02	1.10	1.13	1.17	1.20	1.23	1.20	3.4%	5	5
6	6	Northwest Natural	Yes	Yes	NWN	0.465	1.85	1.82	0.465	0.465	0.465	0.47	1.87	1.85	1.91	1.97	2.03	2.10	2.17	2.10	2.4%	6	6
7	7	Piedmont	Yes	Yes	PNY	0.32	1.27	1.23	0.32	0.33	0.33	0.33	1.31	1.17	1.35	1.39	1.43	1.47	1.51	1.47	3.0%	7	7
8	8	South Jersey	Yes	No	SJI	0.488	0.96	0.90	0.00	0.251	0.251	0.52	1.02	0.96	1.10	1.18	1.26	1.35	1.44	1.35	7.1%	8	8
9	9	Southwest Gas	Yes	No	SWX	0.365	1.43	1.29	0.365	0.405	0.425	0.425	1.62	1.44	1.74	1.85	1.97	2.10	2.23	2.10	8.5%	9	9
10	11	WGL	Yes	No	WGL	0.44	1.74	1.66	0.463	0.463	0.463	0.463	1.85	1.75	1.87	1.91	1.95	1.99	2.03	1.99	3.0%	11	10
11	13	American Water	No	Sensitivity	AWK	0.31	1.21	1.09	0.31	0.34	0.34	0.34	1.33	1.13	1.42	1.51	1.60	1.70	1.80	1.70	7.7%	13	11
12	15	CA Water	No	Sensitivity	CWT	0.1625	0.65	0.64	0.1675	0.1675	0.1675	0.1675	0.67	0.65	0.69	0.77	0.87	0.97	1.07	0.97	7.2%	15	12
13	18	Middlesex Water	No	Sensitivity	MSEX	0.1925	0.76	0.75	0.1925	0.1925	0.1925	0.1925	0.77	0.76	0.78	0.80	0.83	0.85	0.87	0.85	2.1%	18	13
14	20	York Water	No	Sensitivity	YORW	0.1431	0.57	0.56	0.1495	0.1495	0.1495	0.1495	0.60	0.58	0.63	0.68	0.73	0.79	0.85	0.79	5.9%	20	14
		TOTAL	10	2																AVA Peers	4.4%	Mean	
				7																Staff Gas	2.7%		
				w Sensitivities																Staff Gas w AGL	3.3%		
																				Staff Gas w H_2O	4.7%		
																				Staff Gas w AGL & H_2O	4.7%		

Avista - Gas Peer EPS

	1	2	3	4	5	31	32	33	34	35	36	37	38	39		
	#	Abbreviated Utility	UG 288 AVA	UG 288 AVA	Ticker	2016 Q4	2016 Yr	2014-16 Average	2017 Yr	2018 Yr	2019 Yr	2020 Yr	VL Avg 2018 - 20 / Yr	EPS Growth 2018-20 vs. 2012-14	#	
1	1	AGL	Yes	Sensitivity	GAS	1.00	3.35	3.72	3.74	4.17	4.65	5.13	4.65	6.3%	1	1
2	2	Atmos	Yes	No	ATO	0.24	3.20	3.07	3.87	4.67	5.65	6.63	5.65	14.2%	2	2
3	3	Laclede	Yes	No	LG	(0.25)	3.10	2.97	3.43	3.80	4.20	4.60	4.20	8.1%	3	3
4	4	New Jersey	Yes	No	NJR	(0.14)	1.80	1.88	1.82	1.83	1.85	1.87	1.85	2.4%	4	4
5	5	NiSource	Yes	No	NI	0.60	2.05	1.86	2.22	2.40	2.60	2.80	2.60	9.1%	5	5
6	6	Northwest Natural	Yes	Yes	NWN	1.10	2.30	2.12	2.59	2.93	3.30	3.67	3.30	6.9%	6	6
7	7	Piedmont	Yes	Yes	PNY	(0.06)	2.00	1.90	2.03	2.07	2.10	2.13	2.10	3.0%	7	7
8	8	South Jersey	Yes	No	SJI	0.65	1.80	1.68	2.01	2.24	2.50	2.76	2.50	8.4%	8	8
9	9	Southwest Gas	Yes	No	SWX	1.43	3.40	3.19	3.66	3.95	4.25	4.55	4.25	1.0%	9	9
10	11	WGL	Yes	No	WGL	(0.25)	3.00	2.86	3.11	3.23	3.35	3.47	3.35	4.6%	11	10
11	13	American Water	No	Sensitivity	AWK	0.50	2.80	2.60	2.94	3.09	3.25	3.41	3.25	6.8%	13	11
12	15	CA Water	No	Sensitivity	CWT	0.15	1.20	1.20	1.31	1.42	1.55	1.68	1.55	6.3%	15	12
13	18	Middlesex Water	No	Sensitivity	MSEX	0.21	1.20	1.16	1.25	1.30	1.35	1.40	1.35	4.8%	18	13
14	20	York Water	No	Sensitivity	YORW	0.26	1.00	0.95	1.05	1.10	1.15	1.20	1.15	6.5%	20	14
		TOTAL	10	2									AVA Peers	6.4%	Mean	
				7									Staff Gas	5.0%		
				w Sensitivities									Staff Gas w AGL	5.4%		
													Staff Gas w H_2O	5.7%		
													Staff Gas w AGL & H_2O	5.8%		

UG 288 Staff Hamada Adjustments

	1	2	3	4	5	6	7	8	9	10	11
						Yahoo Finance $ Stock Closing Price 1st Trading Day of Month			3-Day Avg $ Stock Price	Div Yield at Recent Price	VL 2015 Return on Common Equity
	#	Abbreviated Utility	UG 246 AVA	UG 246 Staff	Ticker	April 4/1/2015	May 5/1/2015	June 6/1/2015			
1	1	AGL	Yes	Sensitivity	GAS	50.27	50.37	50.36	50.33	3.9%	9.0%
2	2	Atmos	Yes	No	ATO	54.00	54.02	54.09	54.04	2.8%	9.5%
3	3	Laclede	Yes	No	LG	51.93	53.51	53.83	53.09	3.3%	8.5%
4	4	New Jersey	Yes	No	NJR	30.51	30.07	29.97	30.18	2.8%	12.5%
5	5	NiSource	Yes	No	NI	43.42	47.18	47.06	45.89	2.2%	8.5%
6	6	Northwest Natural	Yes	Yes	NWN	46.70	44.70	44.52	45.31	4.1%	6.5%
7	7	Piedmont	Yes	Yes	PNY	37.44	37.29	37.37	31.89	4.0%	11.0%
8	8	South Jersey	Yes	No	SJI	52.75	52.78	60.41	55.31	1.7%	11.5%
9	9	Southwest Gas	Yes	No	SWX	55.00	54.56	55.21	54.92	2.6%	9.5%
10	11	WGL	Yes	No	WGL	55.01	57.54	57.70	56.75	3.1%	12.0%
11	13	American Water	No	Sensitivity	AWK	54.52	52.87	52.85	53.41	2.3%	8.5%
12	15	CA Water	No	Sensitivity	CWT	23.87	23.89	24.14	23.97	2.7%	9.0%
13	18	Middlesex Water	No	Sensitivity	MSEX	22.77	21.83	21.91	22.17	3.4%	9.0%
14	20	York Water	No	Sensitivity	YORW	25.16	22.36	22.64	23.39	2.4%	11.5%
		TOTAL	10	2							
				7			26.39	26.33			
				w Sensitivities							

	#	12	13	14	15	16	17	#	18	19		
		VL 2015 Cap Structure					Relevered Beta Equity at 50.0%			Hamada Adjustment Equity At 51.00%		
		% Long Term Debt	% Common Equity	VL Beta	2015 VL Tax Rate	Hamada Unlevered Beta			Equity Risk Premium		#	
1		48.0	52.0	0.80	37.5%	0.51	0.82		4.20%	0.10%	1	1
2		44.5	55.5	0.85	39.5%	0.57	0.92		4.20%	0.29%	2	2
3		54.0	46.0	0.70	29.0%	0.38	0.65		4.20%	-0.20%	3	3
4		32.5	67.5	0.80	35.0%	0.61	1.01		4.20%	0.86%	4	4
5		56.0	44.0	0.85	37.0%	0.47	0.77		4.20%	-0.34%	5	5
6		44.5	55.5	0.70	40.0%	0.47	0.76		4.20%	0.24%	6	6
7		48.0	52.0	0.80	25.0%	0.47	0.83		4.20%	0.11%	7	7
8		47.0	53.0	0.85	25.0%	0.51	0.89		4.20%	0.18%	8	8
9		49.0	51.0	0.85	35.0%	0.52	0.86		4.20%	0.06%	9	9
10		32.5	66.0	0.90	39.0%	0.69	1.11		4.20%	0.90%	10	10
11		53.5	46.5	0.70	39.5%	0.41	0.66		4.20%	-0.16%	11	11
12		43.0	57.0	0.75	28.5%	0.49	0.84		4.20%	0.36%	15	12
13		40.5	58.5	0.75	34.5%	0.52	0.85		4.20%	0.44%	13	13
14		47.5	52.5	0.7	29.5%	0.43	0.73		4.20%	0.12%	14	14

SJI 2/1 Stock Split in May 2015 is addressed by doubling the May and June share prices.

Dividend Yield = (Annual Dividends per Share) / Price per Share

AVA	Peer Group	Mean	0.22%
Staff	Peer Group		0.18%
AGL	Sensitivity		0.15%
Water	Sensitivity		0.18%
AGL & Water	Sensitivity		0.17%

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Staff Three Stage DCF Modeling

Exhibits in Support
of Opening Testimony

October 16, 2015

Required ROE
Results from Three Stage DCF Modeling

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (**Hamada Adjusted**)

X	**Composite Growth**	**4.71%**	**Historical Growth**	**5.05%**	**Top-10 LT Blue Chip Growth**	**5.08%**
Avista Gas Peers	7.90%	Implied Average ROE	8.16%	Implied Average ROE	8.18%	Implied Average ROE
Staff Gas Peers	8.38%		8.62%		**8.64%**	
Sensitivity w AGL	8.45%		8.70%		8.72%	
Sensitivity w Water	8.07%		8.32%		8.34%	
Sensitivity w AGL & Water	8.15%		8.40%		8.42%	

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (**Hamada Adjusted**)

Y	**Composite Growth**	**4.71%**	**Historical Growth**	**5.05%**	**Top-10 LT Blue Chip Growth**	**5.08%**
Avista Gas Peers	8.23%	Implied Average ROE	8.44%	Implied Average ROE	8.45%	Implied Average ROE
Staff Gas Peers	9.11%		9.31%		**9.33%**	
Sensitivity w AGL	8.91%		9.11%		9.13%	
Sensitivity w Water	8.02%		8.22%		8.24%	
Sensitivity w AGL & Water	8.10%		8.29%		8.31%	

Values Shown Above Are NOT Adjusted Upward Yet for Equity Flotation Costs

Staff Interpretation of ROE Modeling Results

Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :					**12.5**	bps
Range of Modeled Results	Full	8.03%	**to**	9.45%	**ROE**	
	Narrowed	8.31%	**to**	9.45%	**ROE**	
Best Fit Range of Reasonable ROEs		**8.76%**	**to**	**9.45%**	**ROE**	
(Best fit is Staff's Hamada adjusted screened gas utilities that have simial characteristics to AVA Regulated Gas Operations)						
Midpoint of Best Fit Modeling Results			**9.11%**	**ROE**		
(Staff's informed judgement excludes some of the lower range of modeling results depicted above)						
Check of Reasonableness:						
Last Commission Authorized ROE:			**9.50%**			
Change in Long-Term GDP Growth			**9.19%**	(less 31 bps)		
Reduction in risk from frequent rate cases,		**9.00%**	**to**	**9.19%**		
and prompt cost recovery for new facilities.						
Staff Point ROE Recommendation:			**9.11%**	**ROE**		
* Staff Blue Chip Data is sourced from Table 1 Blue Chip Economic Forecast, Feb. 2015						
Note: This analysis does not reflect further downward correction by the CBO on Aug. 25, 2015						
For example Staff's modeling of 2015 GDP growth is not reduced from 2.9% to 2.0%						
See "CBO Cuts US 2015 GPD Forecast to 2% from 2.9%" by Nick Timiraos – WSJ – Aug. 25, 2015						

Illustration of each model is provided on the following pages.

5.05% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

E.O.Y. Cash Flows Staff UG 288 Model X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
						Terminal Value as			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	#	Abbreviated Utility	AVA	Staff	IRR	% of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage						Transition Stage				
1	1	AGL	Yes	Sensitivity	8.7%	55.5%	0.00	(50.33)	1.96	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98
2	2	Atmos	Yes	No	7.7%	69.6%	0.00	(54.04)	1.50	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41
3	3	Laclede	Yes	No	8.2%	62.3%	0.00	(53.09)	1.76	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73
4	4	New Jersey	Yes	No	7.4%	74.5%	0.00	(30.18)	0.86	0.94	0.95	0.97	0.98	0.98	0.99	1.03	1.06	1.10	1.13
5	5	NiSource	Yes	No	6.9%	83.5%	(0.00)	(45.89)	1.02	1.10	1.13	1.17	1.20	1.20	1.23	1.28	1.32	1.37	1.42
6	6	Northwest Natural	Yes	Yes	8.3%	58.2%	0.00	(45.31)	1.85	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39
7	7	Piedmont	Yes	Yes	8.4%	58.1%	0.00	(31.89)	1.27	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71
8	8	South Jersey	Yes	No	7.1%	83.4%	0.00	(55.31)	0.96	1.10	1.18	1.28	1.35	1.35	1.44	1.54	1.65	1.77	1.89
9	9	Southwest Gas	Yes	No	8.3%	63.0%	0.00	(54.92)	1.43	1.74	1.85	1.97	2.10	2.10	2.23	2.42	2.63	2.85	3.09
#	11	WGL	Yes	No	7.5%	71.1%	0.00	(56.75)	1.74	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30
#	13	American Water	No	Sensitivity	7.7%	71.8%	0.00	(53.41)	1.21	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43
#	15	CA Water	No	Sensitivity	8.5%	61.1%	0.00	(23.97)	0.65	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42
#	18	Middlesex Water	No	Sensitivity	7.7%	67.7%	0.00	(22.17)	0.76	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95
#	20	York Water	No	Sensitivity	7.8%	70.5%	0.00	(23.39)	0.57	0.63	0.68	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07
		TOTALS	10	2	Mean														
				7	7.8%	67.9%	0.0%	Avista Gas											
					8.4%	58.1%	0.0%	Staff Gas											
					8.5%	57.3%	0.0%	Staff Sensitivity w AGL)											
					8.1%	64.6%	0.0%	Staff Sensitivity w Water											
					8.2%	63.3%	0.0%	Staff Sensitivity w AGL and Water)											

2	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41		
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043				
Abbreviated Utility	Final Stage																			Terminal Value	2044 Div	2044 Perpetuity	#	
AGL	3.13	3.29	3.45	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.38	5.65	5.94	6.24	6.55	6.89	7.23	7.60	228.82	7.98	220.84	1	1
Atmos	2.53	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	247.05	6.45	240.59	2	2
Laclede	2.87	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	241.48	7.32	234.17	3	3
New Jersey	1.19	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	134.79	3.03	131.76	4	4
NiSource	1.49	1.56	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.44	3.62	206.88	3.80	203.08	5	5
Northwest Natural	2.51	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	200.53	6.40	194.13	6	6
Piedmont	1.79	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.36	141.91	4.58	137.34	7	7
South Jersey	1.99	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	257.51	5.07	252.44	8	8
Southwest Gas	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.57	5.86	6.15	6.46	6.79	7.13	7.49	7.87	261.27	8.27	253.01	9	9
WGL	2.41	2.53	2.66	2.80	2.94	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.58	5.86	253.16	6.15	247.01	11	10
American Water	2.55	2.68	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	250.62	6.50	244.12	13	11
CA Water	1.49	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	114.79	3.80	110.99	15	12
Middlesex Water	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.56	1.63	1.72	1.80	1.90	1.99	2.09	2.20	2.31	2.42	98.09	2.55	95.55	18	13
York Water	1.12	1.18	1.24	1.30	1.37	1.44	1.51	1.59	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	108.80	2.86	105.94	20	14

B.O.Y. Cash Flows Staff UG 288 Model X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
						Terminal Value as			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	#	Abbreviated Utility	AVA	Staff	IRR	% of NPV_{DIV}	NPV @ IRR	Recent Price*	Initial Stage						Transition Stage				
1	1	AGL	Yes	Sensitivity	8.8%	53.3%	0.00	(50.33)	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98	3.13
2	2	Atmos	Yes	No	7.9%	67.4%	0.00	(54.04)	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41	2.53
3	3	Laclede	Yes	No	8.3%	60.1%	0.00	(53.09)	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73	2.87
4	4	New Jersey	Yes	No	7.5%	72.9%	0.00	(30.18)	0.94	0.95	0.97	0.98	0.98	0.99	1.03	1.06	1.10	1.13	1.19
5	5	NiSource	Yes	No	7.0%	81.8%	(0.00)	(45.89)	1.10	1.13	1.17	1.20	1.20	1.23	1.28	1.32	1.37	1.42	1.49
6	6	Northwest Natural	Yes	Yes	8.5%	56.5%	0.00	(45.31)	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39	2.51
7	7	Piedmont	Yes	Yes	8.5%	56.2%	0.00	(31.89)	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71	1.79
8	8	South Jersey	Yes	No	7.2%	81.0%	0.00	(55.31)	1.10	1.18	1.26	1.35	1.35	1.44	1.54	1.65	1.77	1.89	1.99
9	9	Southwest Gas	Yes	No	8.5%	60.0%	0.00	(54.92)	1.74	1.85	1.97	2.10	2.10	2.23	2.42	2.63	2.85	3.09	3.24
#	11	WGL	Yes	No	7.7%	69.5%	0.00	(56.75)	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30	2.41
#	13	American Water	No	Sensitivity	7.9%	69.1%	0.00	(53.41)	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43	2.55
#	15	CA Water	No	Sensitivity	8.7%	58.0%	0.00	(23.97)	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42	1.49
#	18	Middlesex Water	No	Sensitivity	7.8%	66.1%	0.00	(22.17)	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95	1.00
#	20	York Water	No	Sensitivity	7.9%	68.0%	0.00	(23.39)	0.63	0.68	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07	1.12
		TOTALS	10	2	Mean														
				7	8.0%	65.7%	0.0%	Avista Gas											
					8.5%	56.4%	0.0%	Staff Gas											
					8.6%	55.3%	0.0%	Staff Sensitivity w AGL)											
					8.2%	62.3%	0.0%	Staff Sensitivity w Water											
					8.3%	61.0%	0.0%	Staff Sensitivity w AGL and Water)											

2	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41		
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2042				
Abbreviated Utility	Final Stage																			Terminal Value	2044 Div	2044 Perpetuity	#	
AGL	3.29	3.45	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.38	5.65	5.94	6.24	6.55	6.89	7.23	7.60	7.98	229.36	8.38	220.98	1	1
Atmos	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	6.45	247.17	6.78	240.39	2	2
Laclede	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	7.32	241.81	7.69	234.12	3	3
New Jersey	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	3.03	135.30	3.19	132.11	4	4
NiSource	1.56	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.44	3.62	3.80	207.36	3.99	203.37	5	5
Northwest Natural	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	6.40	201.76	6.73	195.04	6	6
Piedmont	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.36	4.58	142.64	4.81	137.83	7	7
South Jersey	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	5.07	256.90	5.33	251.57	8	8
Southwest Gas	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.57	5.86	6.15	6.46	6.79	7.13	7.49	7.87	8.27	259.97	8.69	251.29	9	9
WGL	2.53	2.66	2.80	2.94	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.58	5.86	6.15	254.23	6.46	247.76	11	10
American Water	2.68	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	6.50	249.83	6.83	243.00	13	11
CA Water	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	3.80	114.23	3.99	110.23	15	12
Middlesex Water	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.56	1.63	1.72	1.80	1.90	1.99	2.09	2.20	2.31	2.42	2.55	98.68	2.68	96.00	18	13
York Water	1.18	1.24	1.30	1.37	1.44	1.51	1.59	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	2.86	108.57	3.01	105.56	20	14

Average B.O.Y. & E.O.Y. Cash Flows Model X

	1	2	3	4	5	6	7	8	9
						Terminal Value as	Average 2014 - 2019		
	#	Abbreviated Utility	AVA	Staff	Average IRR	% of NPV_{DIV}	Dividend Growth Rates EOY		
1	1	AGL	Yes	Sensitivity	8.8%	54.4%	3.4%	3.3%	3.4%
2	2	Atmos	Yes	No	7.8%	68.5%	3.7%	3.7%	3.7%
3	3	Laclede	Yes	No	8.3%	61.2%	3.5%	3.4%	3.4%
4	4	New Jersey	Yes	No	7.4%	73.7%	1.0%	1.0%	1.0%
5	5	NiSource	Yes	No	7.0%	82.7%	2.2%	2.2%	2.2%
6	6	Northwest Natural	Yes	Yes	8.4%	57.4%	2.4%	2.4%	2.4%
7	7	Piedmont	Yes	Yes	8.5%	57.2%	2.2%	2.1%	2.1%
8	8	South Jersey	Yes	No	7.1%	82.2%	5.3%	5.1%	5.2%
9	9	Southwest Gas	Yes	No	8.4%	61.5%	4.8%	4.7%	4.8%
#	11	WGL	Yes	No	7.6%	70.3%	1.6%	1.6%	1.6%
#	13	American Water	No	Sensitivity	7.8%	70.5%	4.6%	4.5%	4.6%
#	15	CA Water	No	Sensitivity	8.6%	59.6%	8.9%	6.6%	6.7%
#	18	Middlesex Water	No	Sensitivity	7.8%	66.9%	2.2%	2.2%	2.2%
#	20	York Water	No	Sensitivity	7.8%	69.2%	5.8%	5.7%	5.8%
		TOTALS	10	2	Mean				
				7	7.94%	66.8%	3.7%	Avista Gas	
					8.44%	57.3%	2.3%	Staff Gas	
					8.55%	56.3%	2.6%	Staff Sensitivity w AGL)	
					8.14%	63.5%	4.3%	Staff Sensitivity w Water	
					8.23%	62.2%	4.2%	Staff Sensitivity w AGL and Water)	

5.05% Annual Growth Rate - Stage 3

EPS Growth to Determine a Sale Terminal Value **EPS Growth**

E.O.Y. Cash Flows — Staff Model Y

	1 #	2 Abbreviated Utility	3 AVA	4 Staff	5 IRR	6 Terminal Value as % of NPV_{DIV}	7 NPV @ IRR	8 Recent Price*	9 2014 (Initial Stage)	10 2015	11 2016	12 2017	13 2018	14 2019	15 2020 (Transition Stage)	16 2021	17 2022	18 2023	19 2024
1	1	AGL	Yes	Sensitivity	8.5%	52.0%	0.00	(50.33)	1.96	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98
				e					4.72	3.10	3.35	3.74	4.17	4.65	5.13	5.46	5.81	6.18	6.56
2	2	Atmos	Yes	No	9.8%	99.8%	0.00	(54.04)	1.50	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41
				e					3.01	3.00	3.20	3.87	4.67	5.65	6.63	7.58	8.64	9.81	11.09
3	3	Laclede	Yes	No	9.1%	76.2%	0.00	(53.09)	1.76	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73
				e					2.66	3.15	3.10	3.43	3.80	4.20	4.60	4.99	5.40	5.84	6.30
4	4	New Jersey	Yes	No	6.3%	59.9%	0.00	(30.18)	0.86	0.94	0.95	0.97	0.98	0.98	0.99	1.03	1.06	1.10	1.13
				e					2.10	1.75	1.80	1.82	1.83	1.85	1.87	1.91	1.96	2.01	2.06
5	5	NiSource	Yes	No	8.0%	97.2%	0.00	(45.89)	1.02	1.10	1.13	1.17	1.20	1.20	1.23	1.28	1.32	1.37	1.42
				e					1.69	1.85	2.05	2.22	2.40	2.60	2.80	3.06	3.34	3.64	3.96
6	6	Northwest Natural	Yes	Yes	9.2%	70.6%	0.00	(45.31)	1.85	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39
				e					2.16	1.90	2.30	2.59	2.93	3.30	3.67	3.94	4.21	4.51	4.81
7	7	Piedmont	Yes	Yes	8.1%	53.3%	0.00	(31.89)	1.27	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71
				e					1.84	1.85	2.00	2.03	2.07	2.10	2.13	2.20	2.27	2.34	2.41
8	8	South Jersey	Yes	No	8.1%	97.4%	0.00	(55.31)	0.96	1.10	1.18	1.26	1.35	1.35	1.44	1.54	1.65	1.77	1.89
				e					1.58	1.65	1.80	2.01	2.24	2.50	2.76	3.00	3.25	3.52	3.80
9	9	Southwest Gas	Yes	No	8.2%	61.8%	0.00	(54.92)	1.43	1.74	1.85	1.97	2.10	2.10	2.23	2.42	2.63	2.85	3.09
				e					3.01	3.15	3.40	3.66	3.95	4.25	4.55	4.60	4.65	4.70	4.75
10	11	WGL	Yes	No	7.6%	71.4%	0.00	(56.75)	1.74	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30
				e					2.68	2.90	3.00	3.11	3.23	3.35	3.47	3.64	3.81	3.99	4.17
11	13	American Water	No	Sensitivity	8.0%	76.5%	0.00	(53.41)	1.21	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43
				e					2.39	2.60	2.80	2.94	3.09	3.25	3.41	3.65	3.90	4.17	4.45
12	15	CA Water	No	Sensitivity	8.7%	64.1%	0.00	(23.97)	0.65	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42
				e					1.19	1.20	1.20	1.31	1.42	1.55	1.68	1.79	1.90	2.02	2.14
13	18	Middlesex Water	No	Sensitivity	7.7%	67.1%	0.00	(22.17)	0.76	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95
				e					1.13	1.15	1.20	1.25	1.30	1.35	1.40	1.47	1.55	1.62	1.70
14	20	York Water	No	Sensitivity	7.9%	73.3%	0.00	(23.39)	0.57	0.63	0.68	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07
				e					0.89	0.95	1.00	1.05	1.10	1.15	1.20	1.28	1.37	1.46	1.55
		TOTALS	10	2		Mean													
				7	8.3%	73.1%	0.0%	Avista Gas											
					8.6%	76.5%	0.0%	Staff Gas											
					8.6%	86.9%	0.0%	Staff Sensitivity w AGL)											
					8.3%	72.3%	0.0%	Staff Sensitivity w Water											
					8.3%	78.6%	0.0%	Staff Sensitivity w AGL and Water)											

2 Abbreviated Utility	20 2025 (Final Stage)	21 2026	22 2027	23 2028	24 2029	25 2030	26 2031	27 2032	28 2033	29 2034	30 2035	31 2036	32 2037	33 2038	34 2039	35 2040	36 2041	37 2042	38 2043	39 2043 Terminal Value	40 2044 Div	41 2044 Sale	42 2043	#	
AGL	3.13	3.29	3.45	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.38	5.65	5.94	6.24	6.55	6.89	7.23	7.60	204.97	7.98	196.99		1	1
	6.90	7.24	7.61	7.99	8.40	8.82	9.27	9.74	10.23	10.74	11.29	11.86	12.46	13.08	13.75	14.44	15.17	15.93	16.74		17.58		18.47		
Atmos	2.53	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	566.61	6.45	560.16		2	2
	11.65	12.24	12.85	13.50	14.19	14.90	15.65	16.45	17.28	18.15	19.06	20.03	21.04	22.10	23.22	24.39	25.62	26.92	28.27		29.70		31.20		
Laclede	2.87	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	360.98	7.32	353.66		3	3
	6.62	6.95	7.30	7.67	8.06	8.46	8.89	9.34	9.81	10.31	10.83	11.37	11.95	12.55	13.19	13.85	14.55	15.29	16.06		16.87		17.72		
New Jersey	1.19	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	86.25	3.03	83.22		4	4
	2.16	2.27	2.39	2.51	2.63	2.77	2.90	3.05	3.21	3.37	3.54	3.72	3.90	4.10	4.31	4.53	4.75	4.99	5.25		5.51		5.79		
NiSource	1.49	1.56	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.44	3.62	305.99	3.80	302.20		5	5
	4.15	4.36	4.59	4.82	5.06	5.32	5.58	5.87	6.16	6.47	6.80	7.14	7.50	7.88	8.28	8.70	9.14	9.60	10.09		10.59		11.13		
Northwest Natural	2.51	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	290.55	6.40	284.15		6	6
	5.06	5.31	5.58	5.86	6.16	6.47	6.80	7.14	7.50	7.88	8.28	8.70	9.13	9.60	10.08	10.59	11.12	11.69	12.28		12.90		13.55		
Piedmont	1.79	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.36	122.08	4.58	117.50		7	7
	2.53	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.04	5.30	5.57	5.85	6.14		6.45		6.78		
South Jersey	1.99	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	379.91	5.07	374.84		8	8
	4.00	4.20	4.41	4.63	4.87	5.11	5.37	5.64	5.93	6.23	6.54	6.87	7.22	7.58	7.97	8.37	8.79	9.24	9.70		10.19		10.71		
Southwest Gas	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.57	5.86	6.15	6.46	6.79	7.13	7.49	7.87	252.21	8.27	243.94		9	9
	4.99	5.24	5.51	5.79	6.08	6.38	6.71	7.05	7.40	7.78	8.17	8.58	9.01	9.47	9.95	10.45	10.98	11.53	12.11		12.73		13.37		
WGL	2.41	2.53	2.66	2.80	2.94	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.58	5.86	254.74	6.15	248.59		11	10
	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	6.50	6.83	7.17	7.54	7.92	8.32	8.74	9.18	9.64	10.13	10.64		11.18		11.74		
American Water	2.55	2.68	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	286.17	6.50	279.67		13	11
	4.67	4.91	5.16	5.42	5.69	5.98	6.28	6.60	6.93	7.28	7.65	8.03	8.44	8.86	9.31	9.78	10.28	10.79	11.34		11.91		12.51		
CA Water	1.49	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	125.29	3.80	121.49		15	12
	2.25	2.37	2.49	2.61	2.74	2.88	3.03	3.18	3.34	3.51	3.69	3.87	4.07	4.27	4.49	4.72	4.95	5.20	5.47		5.74		6.03		
Middlesex Water	1.00	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.56	1.63	1.72	1.80	1.90	1.99	2.09	2.20	2.31	2.42	96.40	2.55	93.85		18	13
	1.79	1.88	1.97	2.07	2.17	2.28	2.40	2.52	2.65	2.78	2.92	3.07	3.23	3.39	3.56	3.74	3.93	4.13	4.33		4.55		4.78		
York Water	1.12	1.18	1.24	1.30	1.37	1.44	1.51	1.59	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	117.66	2.86	114.79		20	14
	1.63	1.71	1.80	1.89	1.99	2.09	2.19	2.30	2.42	2.54	2.67	2.80	2.95	3.09	3.25	3.41	3.59	3.77	3.96		4.16		4.37		

B.O.Y. Cash Flows Staff Model Y EPS Growth

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
						Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	#	Abbreviated Utility	AVA	Staff	IRR				Initial Stage						Transition Stage				
1	1	AGL	Yes	Sensitivity	8.8%	52.5%	0.00	(50.33)	2.10	2.20	2.30	2.40	2.40	2.50	2.62	2.73	2.86	2.98	3.13
				e					3.45	3.50	3.66	3.83	4.00	4.17	4.37	4.58	4.79	5.01	5.24
2	2	Atmos	Yes	No	8.3%	74.3%	0.00	(54.04)	1.64	1.72	1.81	1.90	1.90	1.99	2.09	2.19	2.30	2.41	2.53
				e					2.85	3.20	3.37	3.56	3.75	3.94	4.22	4.52	4.84	5.17	5.52
3	3	Laclede	Yes	No	8.3%	60.1%	0.00	(53.09)	1.92	2.01	2.10	2.20	2.20	2.30	2.40	2.51	2.62	2.73	2.87
				e					3.45	3.60	3.76	3.93	4.10	4.27	4.48	4.70	4.92	5.15	5.40
4	4	New Jersey	Yes	No	7.8%	77.2%	0.00	(30.18)	0.94	0.95	0.97	0.98	0.98	0.99	1.03	1.06	1.10	1.13	1.19
				e					2.35	2.55	2.69	2.84	3.00	3.16	3.34	3.53	3.73	3.94	4.16
5	5	NiSource	Yes	No	6.1%	69.3%	0.00	(45.89)	1.10	1.13	1.17	1.20	1.20	1.23	1.28	1.32	1.37	1.42	1.49
				e					2.35	1.30	1.44	1.58	1.75	1.92	2.03	2.14	2.26	2.39	2.52
6	6	Northwest Natural	Yes	Yes	8.2%	52.6%	0.00	(45.31)	1.91	1.97	2.03	2.10	2.10	2.17	2.22	2.28	2.33	2.39	2.51
				e					2.35	1.85	1.97	2.11	2.25	2.39	2.53	2.68	2.83	2.99	3.15
7	7	Piedmont	Yes	Yes	11.0%	93.6%	0.00	(31.89)	1.35	1.39	1.43	1.47	1.47	1.51	1.56	1.61	1.66	1.71	1.79
				e					1.30	3.95	4.05	4.15	4.25	4.35	4.63	4.93	5.24	5.57	5.91
8	8	South Jersey	Yes	No	9.8%	116.9%	0.00	(55.31)	1.10	1.18	1.26	1.35	1.35	1.44	1.54	1.65	1.77	1.89	1.99
				e					1.30	3.65	3.76	3.88	4.00	4.12	4.39	4.67	4.96	5.27	5.60
9	9	Southwest Gas	Yes	No	11.5%	106.4%	0.00	(54.92)	1.74	1.85	1.97	2.10	2.10	2.23	2.42	2.63	2.85	3.09	3.24
				e					1.30	4.55	4.77	5.01	5.25	5.49	5.85	6.22	6.62	7.03	7.46
10	11	WGL	Yes	No	7.3%	64.6%	0.00	(56.75)	1.87	1.91	1.95	1.99	1.99	2.03	2.10	2.16	2.23	2.30	2.41
				e					3.90	3.75	3.98	4.23	4.50	4.77	4.85	4.94	5.03	5.12	5.22
11	13	American Water	No	Sensitivity	6.5%	46.7%	0.00	(53.41)	1.42	1.51	1.60	1.70	1.70	1.80	1.94	2.09	2.26	2.43	2.55
				e					4.45	2.05	2.19	2.34	2.50	2.66	2.81	2.97	3.13	3.30	3.48
12	15	CA Water	No	Sensitivity	9.1%	64.3%	0.00	(23.97)	0.69	0.77	0.87	0.97	0.97	1.07	1.15	1.24	1.33	1.42	1.49
				e					4.00	5.45	5.85	6.29	6.75	7.21	7.35	7.49	7.63	7.77	7.91
13	18	Middlesex Water	No	Sensitivity	5.7%	31.9%	0.00	(22.17)	0.78	0.80	0.83	0.85	0.85	0.87	0.89	0.91	0.93	0.95	1.00
				e					5.90	1.60	1.72	1.86	2.00	2.14	2.23	2.31	2.40	2.49	2.58
14	20	York Water	No	Sensitivity	6.5%	45.8%	0.00	(23.39)	0.63	0.68	0.73	0.79	0.79	0.85	0.90	0.95	1.01	1.07	1.12
				e					5.90	3.60	3.65	3.70	3.75	3.80	3.95	4.10	4.26	4.42	4.58
		TOTALS	10	2		Mean													
				7	8.7%	68.3%	0.0%	Avista Gas											
					9.6%	73.2%	0.0%	Staff Gas											
					9.4%	66.3%	0.0%	Staff Sensitivity w AGL)											
					7.8%	55.8%	0.0%	Staff Sensitivity w Water											
					6.9%	60.3%	0.0%	Staff Sensitivity w AGL and Water)											

#	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
	Final Stage																		
1	3.29	3.45	3.63	3.81	4.00	4.21	4.42	4.64	4.88	5.12	5.38	5.65	5.94	6.24	6.55	6.89	7.23	7.60	7.98
	5.50	5.78	6.07	6.38	6.70	7.04	7.40	7.77	8.16	8.57	9.01	9.46	9.94	10.44	10.97	11.52	12.10	12.72	13.36
2	2.66	2.79	2.93	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.57	4.80	5.05	5.30	5.57	5.85	6.14	6.45
	5.80	6.09	6.40	6.72	7.06	7.42	7.79	8.19	8.60	9.04	9.49	9.97	10.47	11.00	11.56	12.14	12.76	13.40	14.08
3	3.01	3.17	3.33	3.49	3.67	3.86	4.05	4.26	4.47	4.70	4.93	5.18	5.45	5.72	6.01	6.31	6.63	6.97	7.32
	5.67	5.96	6.26	6.57	6.90	7.25	7.62	8.00	8.41	8.83	9.28	9.75	10.24	10.76	11.30	11.87	12.47	13.10	13.76
4	1.25	1.31	1.38	1.45	1.52	1.60	1.68	1.76	1.85	1.95	2.05	2.15	2.26	2.37	2.49	2.62	2.75	2.89	3.03
	4.37	4.59	4.82	5.07	5.32	5.59	5.88	6.17	6.48	6.81	7.16	7.52	7.90	8.30	8.71	9.15	9.62	10.10	10.61
5	1.56	1.64	1.73	1.81	1.91	2.00	2.10	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.44	3.62	3.80
	2.65	2.79	2.93	3.07	3.23	3.39	3.56	3.74	3.93	4.13	4.34	4.56	4.79	5.03	5.28	5.55	5.83	6.13	6.44
6	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.11	4.32	4.53	4.76	5.00	5.26	5.52	5.80	6.09	6.40
	3.31	3.48	3.65	3.84	4.03	4.24	4.45	4.68	4.91	5.16	5.42	5.69	5.98	6.28	6.60	6.93	7.28	7.65	8.04
7	1.88	1.98	2.08	2.19	2.30	2.41	2.53	2.66	2.80	2.94	3.08	3.24	3.40	3.58	3.76	3.95	4.15	4.36	4.58
	6.21	6.52	6.85	7.20	7.56	7.95	8.35	8.77	9.21	9.68	10.16	10.68	11.22	11.78	12.38	13.00	13.66	14.35	15.08
8	2.09	2.19	2.31	2.42	2.54	2.67	2.81	2.95	3.10	3.26	3.42	3.59	3.77	3.96	4.16	4.37	4.60	4.83	5.07
	5.88	6.18	6.49	6.82	7.16	7.52	7.90	8.30	8.72	9.16	9.62	10.11	10.62	11.16	11.72	12.31	12.93	13.59	14.27
9	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.57	5.86	6.15	6.46	6.79	7.13	7.49	7.87	8.27
	7.84	8.24	8.65	9.09	9.55	10.03	10.54	11.07	11.63	12.22	12.83	13.48	14.16	14.88	15.63	16.42	17.25	18.12	19.03
11	2.53	2.66	2.80	2.94	3.09	3.24	3.41	3.58	3.76	3.95	4.15	4.36	4.58	4.81	5.05	5.31	5.58	5.86	6.15
	5.48	5.76	6.05	6.35	6.67	7.01	7.36	7.73	8.13	8.54	8.97	9.42	9.90	10.39	10.92	11.47	12.05	12.66	13.30
13	2.68	2.81	2.95	3.10	3.26	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.84	5.08	5.34	5.61	5.89	6.19	6.50
	3.66	3.84	4.04	4.24	4.45	4.68	4.91	5.16	5.42	5.70	5.99	6.29	6.61	6.94	7.29	7.66	8.04	8.45	8.88
15	1.57	1.65	1.73	1.82	1.91	2.00	2.11	2.21	2.32	2.44	2.56	2.69	2.83	2.97	3.12	3.28	3.45	3.62	3.80
	8.31	8.73	9.17	9.64	10.12	10.64	11.17	11.74	12.33	12.95	13.61	14.29	15.02	15.77	16.57	17.41	18.29	19.21	20.18
18	1.05	1.10	1.16	1.22	1.28	1.34	1.41	1.48	1.56	1.63	1.72	1.80	1.90	1.99	2.09	2.20	2.31	2.42	2.55
	2.71	2.85	3.00	3.15	3.31	3.47	3.65	3.83	4.03	4.23	4.44	4.67	4.90	5.15	5.41	5.68	5.97	6.27	6.59
20	1.18	1.24	1.30	1.37	1.44	1.51	1.59	1.67	1.75	1.84	1.93	2.03	2.13	2.24	2.35	2.47	2.59	2.73	2.86
	4.81	5.05	5.31	5.58	5.86	6.16	6.47	6.80	7.14	7.50	7.88	8.28	8.69	9.13	9.59	10.08	10.59	11.12	11.68

#	39	40	41	42		
	2043 Terminal Value	2044 Div	2044 Sale	2043	#	
1	223.44	8.38	215.05		1	1
		14.03		14.74		
2	301.32	6.78	294.54		2	2
		14.79		15.53		
3	241.36	7.69	233.67		3	3
		14.46		15.19		
4	153.61	3.19	150.42		4	4
		11.15		11.71		
5	142.66	3.99	138.67		5	5
		6.76		7.10		
6	177.75	6.73	171.02		6	6
		8.44		8.87		
7	412.91	4.81	408.10		7	7
		15.84		16.64		
8	675.42	5.33	670.09		8	8
		14.99		15.75		
9	895.99	8.69	887.30		9	9
		19.99		21.00		
11	220.01	6.46	213.54		11	10
		13.97		14.68		
13	124.41	6.83	117.58		13	11
		9.33		9.80		
15	137.42	3.99	133.43		15	12
		21.20		22.27		
18	30.00	2.68	27.32		18	13
		6.92		7.27		
20	54.12	3.01	51.11		20	14
		12.27		12.89		

Average B.O.Y. & E.O.Y. Cash Flows Model Y EPS Growth

	1	2	3	4	5	6	7	8	9
	#	Abbreviated Utility	AVA	Staff	Average IRR	Terminal Value as % of NPV_{DIV}	Average 2014 - 2019 Dividend Growth Rates EOY		
1	1	AGL	Yes	Sensitivity	8.6%	52.2%	3.4%	3.3%	3.4%
2	2	Atmos	Yes	No	9.1%	87.0%	3.7%	3.7%	3.7%
3	3	Laclede	Yes	No	8.7%	68.1%	3.5%	3.4%	3.4%
4	4	New Jersey	Yes	No	7.1%	88.5%	1.0%	1.0%	1.0%
5	5	NiSource	Yes	No	7.0%	83.2%	2.2%	2.2%	2.2%
6	6	Northwest Natural	Yes	Yes	8.7%	61.6%	2.4%	2.4%	2.4%
7	7	Piedmont	Yes	Yes	9.6%	73.6%	2.2%	2.1%	2.1%
8	8	South Jersey	Yes	No	9.0%	107.1%	5.3%	5.1%	5.2%
9	9	Southwest Gas	Yes	No	9.9%	84.1%	4.8%	4.7%	4.8%
10	11	WGL	Yes	No	7.4%	68.0%	1.6%	1.6%	1.6%
11	13	American Water	No	Sensitivity	7.2%	61.6%	4.6%	4.5%	4.6%
12	15	CA Water	No	Sensitivity	8.9%	64.2%	8.9%	8.6%	8.7%
13	18	Middlesex Water	No	Sensitivity	6.7%	49.5%	2.2%	2.2%	2.2%
14	20	York Water	No	Sensitivity	7.2%	59.5%	5.8%	5.7%	5.8%
		TOTALS	10	2	Mean				
				7	8.22%	70.6%	3.7%	Avista Gas	
				w Sensitivities	9.13%	67.6%	2.3%	Staff Gas	
					8.96%	62.5%	2.6%	Staff Sensitivity w AGL)	
					8.04%	61.7%	4.3%	Staff Sensitivity w Water	
					8.12%	60.3%	4.2%	Staff Sensitivity w AGL and Water)	

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Staff Synthetic Forward Curve TIPS Analysis

Exhibits in Support
of Opening Testimony

October 16, 2015

2024 through 2044 TIPs-Implied Average Annual Inflation Rate: 2.12%

Yr. End		Individually Implied Price Levels					Implied Forward Curve/Price Level					Implied	
Mo.-Yr.	Years	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Price Level	Check
Dec-14	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Dec-15	1	101.41	101.61	101.83	101.95	102.02	101.41					101.41	
Dec-16	2	102.85	103.25	103.70	103.93	104.09	102.85					102.85	
Dec-17	3	104.30	104.91	105.60	105.95	106.19	104.30					104.30	
Dec-18	4	105.77	106.60	107.54	108.02	108.34	105.77					105.77	
Dec-19	5	107.27	108.31	109.51	110.12	110.53	107.27					107.27	
Dec-20	6		110.06	111.52	112.26	112.77		109.53				109.53	
Dec-21	7		111.83	113.56	114.45	115.05		111.83				111.83	
Dec-22	8			115.64	116.68	117.38			114.46			114.46	
Dec-23	9			117.76	118.95	119.76			117.16			117.16	
Dec-24	10			119.92	121.26	122.18			119.92			119.92	
Dec-25	11				123.62	124.65				122.39		122.39	122.46
Dec-26	12				126.03	127.17				124.91		124.91	125.06
Dec-27	13				128.48	129.75				127.49		127.49	127.71
Dec-28	14				130.99	132.37				130.11		130.11	130.41
Dec-29	15				133.54	135.05				132.79		132.79	133.17
Dec-30	16				136.13	137.78				135.53		135.53	136.00
Dec-31	17				138.78	140.57				138.32		138.32	138.88
Dec-32	18				141.49	143.41				141.17		141.17	141.82
Dec-33	19				144.24	146.32				144.08		144.08	144.82
Dec-34	20				147.05	149.28				147.05		147.05	147.89
Dec-35	21					152.30					150.25	150.25	151.02
Dec-36	22					155.38					153.52	153.52	154.22
Dec-37	23					158.52					156.86	156.86	157.49
Dec-38	24					161.73					160.28	160.28	160.83
Dec-39	25					165.00					163.77	163.77	164.23
Dec-40	26					168.34					167.33	167.33	167.71
Dec-41	27					171.75					170.97	170.97	171.27
Dec-42	28					175.22					174.69	174.69	174.89
Dec-43	29					178.77					178.50	178.50	178.60
Dec-44	30					182.38					182.38	182.38	182.38

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis **Quarterly Aggregation**

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	**-1.08**	**-0.75**	**-0.35**	**0.35**	**0.66**
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	**-1.42**	**-1.15**	**-0.76**	**-0.02**	**0.36**
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	**-1.04**	**-0.62**	**-0.25**	**0.47**	**0.80**
2013-Q3	-0.32	0.17	0.56	1.16	1.43
2013-Q4	**-0.29**	**0.25**	**0.57**	**1.19**	**1.50**
2014-Q1	-0.16	0.37	0.58	1.11	1.39
2014-Q2	**-0.25**	**0.27**	**0.43**	**0.88**	**1.44**
2014-Q3	-0.13	0.24	0.32	0.72	0.98
2014-Q4	**0.19**	**0.39**	**0.45**	**0.75**	**0.95**

Average Monthly Nominal UST Rates by Quarter					
Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	**0.79**	**1.24**	**1.82**	**2.55**	**2.94**
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	**0.69**	**1.12**	**1.71**	**2.46**	**2.86**
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	**0.92**	**1.39**	**2.00**	**2.78**	**3.15**
2013-Q3	1.51	2.12	2.71	3.44	3.72
2013-Q4	**1.44**	**2.12**	**2.75**	**3.50**	**3.79**
2014-Q1	1.60	2.22	2.76	3.42	3.68
2014-Q2	**1.66**	**2.19**	**2.62**	**3.18**	**3.23**
2014-Q3	1.70	2.16	2.50	3.01	3.26
2014-Q4	**1.60**	**2.00**	**2.28**	**2.69**	**2.97**

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	**1.86**	**1.99**	**2.17**	**2.21**	**2.28**
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	**2.11**	**2.27**	**2.47**	**2.48**	**2.50**
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	**1.95**	**2.01**	**2.25**	**2.32**	**2.34**
2013-Q3	1.82	1.95	2.15	2.29	2.29
2013-Q4	**1.73**	**1.86**	**2.17**	**2.31**	**2.29**
2014-Q1	1.77	1.85	2.18	2.30	2.29
2014-Q2	**1.90**	**1.92**	**2.20**	**2.30**	**1.79**
2014-Q3	1.83	1.92	2.18	2.28	2.29
2014-Q4	**1.41**	**1.61**	**1.83**	**1.95**	**2.02**

FRB **H.15** Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year

Staff Accessed , Feb. 5, 2015 at: http://federalreserve.gov/releases/h15/data.htm

Last Updated: 1-Apr-14 @ http://www.federalreserve.gov/releases/H15/data.htm

Monthly

TIPS-05m	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.M
TIPS-07m	7				RIFLGFCY07_XII_N.M
TIPS-10m	10				RIFLGFCY10_XII_N.M
TIPS-20m	20				RIFLGFCY20_XII_N.M
TIPS-30m	30				RIFLGFCY30_XII_N.M

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-01	1.65	2.10	2.29		
2003-02	1.24	1.74	1.99		
2003-03	1.09	1.60	1.94		
2003-04	1.36	1.85	2.18		
2003-05	1.18	1.61	1.91		
2003-06	0.91	1.37	1.72		
2003-07	1.30	1.76	2.11		
2003-08	1.48	1.97	2.32		
2003-09	1.29	1.80	2.19		
2003-10	1.21	1.68	2.08		
2003-11	1.27	1.64	1.96		
2003-12	1.23	1.64	1.98		
2004-01	1.09	1.48	1.89		
2004-02	0.86	1.31	1.76		
2004-03	0.52	0.98	1.47		
2004-04	1.02	1.49	1.90		
2004-05	1.34	1.77	2.09		
2004-06	1.41	1.80	2.15	TIPS-20	
2004-07	1.29	1.68	2.02	2.44	
2004-08	1.12	1.51	1.86	2.23	
2004-09	1.10	1.46	1.80	2.16	
2004-10	0.97	1.35	1.73	2.13	
2004-11	0.90	1.27	1.68	2.09	
2004-12	0.92	1.28	1.67	2.02	
2005-01	1.13	1.40	1.72	1.98	
2005-02	1.08	1.33	1.63	1.85	
2005-03	1.29	1.49	1.79	1.95	
2005-04	1.23	1.42	1.71	1.87	
2005-05	1.28	1.41	1.65	1.82	
2005-06	1.39	1.49	1.67	1.80	
2005-07	1.67	1.75	1.88	2.00	
2005-08	1.71	1.79	1.89	2.02	
2005-09	1.40	1.56	1.70	1.93	
2005-10	1.70	1.82	1.94	2.09	
2005-11	1.97	2.03	2.06	2.16	
2005-12	2.09	2.10	2.12	2.14	
2006-01	1.93	1.96	2.01	2.05	
2006-02	1.98	2.02	2.05	2.01	
2006-03	2.09	2.15	2.20	2.17	
2006-04	2.26	2.34	2.41	2.43	
2006-05	2.30	2.36	2.45	2.48	
2006-06	2.45	2.48	2.53	2.54	
2006-07	2.46	2.48	2.51	2.52	
2006-08	2.27	2.29	2.29	2.31	
2006-09	2.38	2.35	2.32	2.31	
2006-10	2.51	2.45	2.41	2.38	
2006-11	2.41	2.35	2.29	2.23	
2006-12	2.28	2.28	2.25	2.26	
2007-01	2.47	2.47	2.44	2.42	
2007-02	2.34	2.38	2.36	2.38	
2007-03	2.04	2.14	2.18	2.27	
2007-04	2.12	2.20	2.26	2.35	
2007-05	2.29	2.32	2.37	2.45	
2007-06	2.65	2.87	2.69	2.67	
2007-07	2.60	2.63	2.64	2.62	
2007-08	2.39	2.45	2.44	2.47	
2007-09	2.14	2.24	2.26	2.30	
2007-10	2.01	2.15	2.20	2.26	
2007-11	1.35	1.65	1.77	1.99	
2007-12	1.27	1.62	1.79	2.08	
2008-01	0.86	1.24	1.47	1.81	
2008-02	0.65	1.09	1.41	1.87	
2008-03	0.23	0.73	1.09	1.76	
2008-04	0.62	1.00	1.36	1.91	
2008-05	0.79	1.16	1.46	2.00	
2008-06	0.97	1.35	1.63	2.19	
2008-07	0.84	1.24	1.57	2.09	
2008-08	1.15	1.47	1.68	2.15	
2008-09	1.55	1.71	1.85	2.25	
2008-10	2.75	2.96	2.75	2.87	
2008-11	3.69	3.84	2.89	3.00	
2008-12	1.76	1.96	2.17	2.32	
2009-01	1.59	1.72	1.91	2.46	
2009-02	1.29	1.48	1.75	2.31	
2009-03	1.23	1.43	1.71	2.26	
2009-04	1.11	1.29	1.57	2.22	
2009-05	1.07	1.34	1.72	2.36	
2009-06	1.18	1.48	1.86	2.36	
2009-07	1.18	1.44	1.82	2.31	
2009-08	1.29	1.49	1.77	2.22	
2009-09	1.03	1.29	1.64	2.13	
2009-10	0.83	1.12	1.48	2.04	
2009-11	0.48	0.84	1.28	1.90	
2009-12	0.43	0.86	1.36	1.99	
2010-01	0.42	0.85	1.37	2.00	TIPS-30
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.08	1.51	1.98	2.15
2010-04	0.62	1.10	1.50	1.90	2.05
2010-05	0.41	0.86	1.31	1.72	1.83
2010-06	0.34	0.76	1.26	1.69	1.77
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	-0.32	0.02	0.53	1.32	1.44
2010-11	-0.21	0.17	0.67	1.44	1.61
2010-12	0.21	0.65	1.04	1.67	1.89
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	-0.14	0.49	0.86	1.48	1.79
2011-05	-0.34	0.29	0.78	1.47	1.77
2011-06	-0.38	0.21	0.76	1.53	1.78
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	-0.63	-0.28	0.19	0.72	0.99
2011-11	-0.85	-0.46	0.00	0.55	0.78
2011-12	-0.78	-0.44	-0.03	0.56	0.78
2012-01	-0.92	-0.55	-0.11	0.51	0.74
2012-02	-1.11	-0.69	-0.25	0.45	0.72
2012-03	-1.03	-0.57	-0.14	0.56	0.87
2012-04	**-1.06**	**-0.65**	**-0.21**	**0.50**	**0.79**
2012-05	**-1.12**	**-0.79**	**-0.34**	**0.44**	**0.68**
2012-06	**-1.05**	**-0.82**	**-0.50**	**0.10**	**0.50**
2012-07	-1.15	-0.92	-0.60	-0.01	0.39
2012-08	-1.19	-0.94	-0.59	0.06	0.47
2012-09	-1.47	-1.17	-0.71	0.02	0.44
2012-10	**-1.47**	**-1.18**	**-0.75**	**-0.01**	**0.41**
2012-11	**-1.38**	**-1.13**	**-0.77**	**-0.06**	**0.35**
2012-12	**-1.40**	**-1.13**	**-0.76**	**0.00**	**0.33**
2013-01	-1.39	-1.04	-0.61	0.20	0.48
2013-02	-1.39	-0.94	-0.57	0.19	0.57
2013-03	-1.43	-0.97	-0.59	0.19	0.62
2013-04	**-1.38**	**-0.97**	**-0.65**	**0.07**	**0.48**
2013-05	**-1.14**	**-0.69**	**-0.36**	**0.35**	**0.72**
2013-06	**-0.59**	**-0.21**	**0.25**	**0.98**	**1.21**
2013-07	-0.45	0.02	0.46	1.09	1.34
2013-08	-0.33	0.15	0.55	1.16	1.44
2013-09	-0.17	0.34	0.66	1.22	1.50
2013-10	**-0.41**	**0.11**	**0.43**	**1.05**	**1.37**
2013-11	**-0.38**	**0.18**	**0.55**	**1.20**	**1.51**
2013-12	**-0.09**	**0.47**	**0.74**	**1.32**	**1.61**
2014-01	-0.09	0.45	0.63	1.17	1.44
2014-02	-0.26	0.30	0.55	1.12	1.40
2014-03	-0.14	0.37	0.56	1.05	1.33
2014-04	**-0.11**	**0.38**	**0.54**	**0.98**	**1.23**
2014-05	**-0.34**	**0.21**	**0.37**	**0.82**	**1.08**
2014-06	**-0.29**	**0.23**	**0.37**	**0.84**	**1.11**
2014-07	-0.27	0.18	0.28	0.72	0.98
2014-08	-0.21	0.15	0.22	0.64	0.90
2014-09	0.10	0.38	0.46	0.81	1.05
2014-10	**0.06**	**0.32**	**0.38**	**0.74**	**0.96**
2014-11	**0.14**	**0.37**	**0.45**	**0.77**	**0.99**
2014-12	**0.37**	**0.47**	**0.51**	**0.73**	**0.89**

Monthly

UST-05m	5	Year	H.15 ID	RIFLGFCY05_N.M
UST-07m	7			RIFLGFCY07_N.M
UST-10m	10			RIFLGFCY10_N.M
UST-20m	20			RIFLGFCY20_N.M
UST-30m	30			RIFLGFCY30_N.M

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-01	3.05	3.60	4.05	5.02	
2003-02	2.90	3.45	3.90	4.87	
2003-03	2.78	3.34	3.81	4.82	
2003-04	2.93	3.47	3.96	4.91	
2003-05	2.52	3.07	3.57	4.52	
2003-06	2.27	2.84	3.33	4.34	
2003-07	2.87	3.45	3.98	4.92	
2003-08	3.37	3.96	4.45	5.39	
2003-09	3.18	3.74	4.27	5.21	
2003-10	3.19	3.75	4.29	5.21	
2003-11	3.29	3.81	4.30	5.17	
2003-12	3.27	3.79	4.27	5.11	
2004-01	3.12	3.65	4.15	5.01	
2004-02	3.07	3.59	4.08	4.94	
2004-03	2.79	3.31	3.83	4.72	
2004-04	3.39	3.89	4.35	5.16	
2004-05	3.85	4.31	4.72	5.46	
2004-06	3.93	4.35	4.73	5.45	
2004-07	3.69	4.11	4.50	5.24	
2004-08	3.47	3.90	4.28	5.07	
2004-09	3.36	3.75	4.13	4.89	
2004-10	3.35	3.75	4.10	4.85	
2004-11	3.53	3.88	4.19	4.89	
2004-12	3.60	3.93	4.23	4.88	
2005-01	3.71	3.97	4.22	4.77	
2005-02	3.77	3.97	4.17	4.61	
2005-03	4.17	4.33	4.50	4.89	
2005-04	4.00	4.16	4.34	4.75	
2005-05	3.85	3.94	4.14	4.56	
2005-06	3.77	3.86	4.00	4.35	
2005-07	3.98	4.06	4.16	4.48	
2005-08	4.12	4.18	4.26	4.53	
2005-09	4.01	4.08	4.20	4.51	
2005-10	4.33	4.38	4.46	4.74	
2005-11	4.45	4.48	4.54	4.83	
2005-12	4.39	4.41	4.47	4.73	
2006-01	4.35	4.37	4.42	4.65	UST-30
2006-02	4.57	4.56	4.57	4.73	4.54
2006-03	4.72	4.71	4.72	4.91	4.73
2006-04	4.90	4.94	4.99	5.22	5.06
2006-05	5.00	5.03	5.11	5.35	5.20
2006-06	5.07	5.08	5.11	5.29	5.15
2006-07	5.04	5.05	5.09	5.25	5.13
2006-08	4.82	4.83	4.88	5.08	5.00
2006-09	4.67	4.68	4.72	4.93	4.85
2006-10	4.69	4.69	4.73	4.94	4.85
2006-11	4.58	4.58	4.60	4.78	4.69
2006-12	4.53	4.54	4.56	4.78	4.68
2007-01	4.75	4.75	4.76	4.95	4.85
2007-02	4.71	4.71	4.72	4.93	4.82
2007-03	4.48	4.50	4.56	4.81	4.72
2007-04	4.59	4.62	4.69	4.95	4.87
2007-05	4.67	4.69	4.75	4.98	4.90
2007-06	5.03	5.05	5.10	5.29	5.20
2007-07	4.88	4.93	5.00	5.19	5.11
2007-08	4.43	4.53	4.67	5.00	4.93
2007-09	4.20	4.33	4.52	4.84	4.79
2007-10	4.20	4.33	4.53	4.83	4.77
2007-11	3.67	3.87	4.15	4.56	4.52
2007-12	3.49	3.74	4.10	4.57	4.53
2008-01	2.98	3.31	3.74	4.35	4.33
2008-02	2.78	3.21	3.74	4.49	4.52
2008-03	2.48	2.93	3.51	4.36	4.39
2008-04	2.84	3.19	3.68	4.44	4.44
2008-05	3.15	3.46	3.88	4.60	4.60
2008-06	3.49	3.73	4.10	4.74	4.69
2008-07	3.30	3.60	4.01	4.62	4.57
2008-08	3.14	3.46	3.89	4.53	4.50
2008-09	2.88	3.25	3.69	4.32	4.27
2008-10	2.73	3.19	3.81	4.45	4.17
2008-11	2.29	2.82	3.53	4.27	4.00
2008-12	1.52	1.89	2.42	3.18	2.87
2009-01	1.60	1.98	2.52	3.46	3.13
2009-02	1.87	2.30	2.67	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.66	2.47	2.93	3.84	3.76
2009-05	2.13	2.81	3.29	4.22	4.23
2009-06	2.71	3.37	3.72	4.51	4.52
2009-07	2.46	3.14	3.56	4.38	4.41
2009-08	2.57	3.21	3.59	4.33	4.37
2009-09	2.37	3.02	3.40	4.14	4.19
2009-10	2.33	2.96	3.39	4.16	4.19
2009-11	2.23	2.92	3.40	4.24	4.31
2009-12	2.34	3.07	3.59	4.40	4.49
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	2.58	3.28	3.85	4.53	4.69
2010-05	2.18	2.86	3.42	4.11	4.29
2010-06	2.00	2.66	3.20	3.95	4.13
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	1.18	1.85	2.54	3.52	3.87
2010-11	1.35	2.02	2.76	3.82	4.19
2010-12	1.93	2.66	3.29	4.17	4.42
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	2.17	2.84	3.46	4.28	4.50
2011-05	1.84	2.51	3.17	4.01	4.29
2011-06	1.58	2.29	3.00	3.91	4.23
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	1.06	1.62	2.15	2.87	3.13
2011-11	0.91	1.45	2.01	2.72	3.02
2011-12	0.89	1.43	1.98	2.67	2.98
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	**0.89**	**1.43**	**2.05**	**2.82**	**3.18**
2012-05	**0.76**	**1.21**	**1.80**	**2.53**	**2.93**
2012-06	**0.71**	**1.08**	**1.62**	**2.31**	**2.70**
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	**0.71**	**1.15**	**1.75**	**2.51**	**2.90**
2012-11	**0.67**	**1.08**	**1.65**	**2.39**	**2.80**
2012-12	**0.70**	**1.13**	**1.72**	**2.47**	**2.88**
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	**0.71**	**1.15**	**1.76**	**2.55**	**2.93**
2013-05	**0.84**	**1.31**	**1.93**	**2.73**	**3.11**
2013-06	**1.20**	**1.71**	**2.30**	**3.07**	**3.40**
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	**1.37**	**1.99**	**2.62**	**3.38**	**3.68**
2013-11	**1.37**	**2.07**	**2.72**	**3.50**	**3.80**
2013-12	**1.58**	**2.29**	**2.90**	**3.63**	**3.89**
2014-01	1.65	2.29	2.86	3.52	3.77
2014-02	1.52	2.15	2.71	3.38	3.66
2014-03	1.64	2.23	2.72	3.35	3.62
2014-04	**1.70**	**2.27**	**2.71**	**3.27**	**3.52**
2014-05	**1.59**	**2.12**	**2.56**	**3.12**	**3.39**
2014-06	**1.68**	**2.19**	**2.60**	**3.15**	**3.42**
2014-07	1.70	2.17	2.54	3.07	3.33
2014-08	1.63	2.08	2.42	2.94	3.20
2014-09	1.77	2.22	2.53	3.01	3.26
2014-10	**1.55**	**1.98**	**2.30**	**2.77**	**3.04**
2014-11	**1.62**	**2.03**	**2.33**	**2.76**	**3.04**
2014-12	**1.64**	**1.98**	**2.21**	**2.55**	**2.83**

NWN UG 221

PGE & PAC UE 262 UE 263

AVA UG 246

PGE UE 283

PGE UE 294

Annual

TIPS-05a	5	Year	Inflation Indexed	H.15 ID	RIFLGFCY05_XII_N.A
TIPS-07a	7				RIFLGFCY07_XII_N.A
TIPS-10a	10				RIFLGFCY10_XII_N.A
TIPS-20a	20				RIFLGFCY20_XII_N.A
TIPS-30a	30				RIFLGFCY30_XII_N.A

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.63	1.81	1.97	
2006	2.28	2.29	2.31	2.31	
2007	2.15	2.25	2.29	2.38	
2008	1.30	1.83	1.77	2.18	
2009	1.06	1.32	1.86	2.21	
2010	0.26	0.68	1.15	1.73	1.82
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07
2014	**-0.09**	**0.32**	**0.44**	**0.86**	**1.11**

Annual

UST-05a	5	Year	H.15 ID	RIFLGFCY05_N.A
UST-07a	7			RIFLGFCY07_N.A
UST-10a	10			RIFLGFCY10_N.A
UST-20a	20			RIFLGFCY20_N.A
UST-30a	30			RIFLGFCY30_N.A

Year	UST-05a	UST-07a	UST-10a	UST-20a	UST-30a
2003	2.97	3.52	4.01	4.96	
2004	3.43	3.87	4.27	5.04	
2005	4.05	4.15	4.29	4.64	
2006	4.75	4.76	4.80	5.00	4.91
2007	4.43	4.51	4.63	4.91	4.84
2008	2.80	3.17	3.66	4.36	4.28
2009	2.20	2.82	3.26	4.11	4.08
2010	1.93	2.62	3.22	4.03	4.25
2011	1.52	2.16	2.78	3.62	3.91
2012	0.76	1.22	1.80	2.54	2.92
2013	1.17	1.74	2.35	3.12	3.45
2014	**1.64**	**2.14**	**2.54**	**3.07**	**3.34**

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Staff Historical GDP Analysis with BEA Data

Exhibits in Support
of Opening Testimony

October 16, 2015

Bureau of Economic Analysis (BEA)

Current-Dollar and "Real" Gross Domestic Product (GDP)

Annual

http://www.bea.gov/national/index.htm

Yr	GDP in billions of current dollars	GDP in billions of chained 2009 dollars
1929	104.6	1,056.6
1930	92.2	966.7
1931	77.4	904.8
1932	59.5	788.2
1933	57.2	778.3
1934	66.8	862.2
1935	74.3	939.0
1936	84.9	1,060.5
1937	93.0	1,114.6
1938	87.4	1,077.7
1939	93.5	1,163.6
1940	102.9	1,266.1
1941	129.4	1,490.3
1942	166.0	1,771.8
1943	203.1	2,073.7
1944	224.6	2,239.4
1945	228.2	2,217.8
1946	227.8	1,960.9
1947	249.9	1,939.4
1948	274.8	2,020.0
1949	272.8	2,008.9
1950	300.2	2,184.0
1951	347.3	2,360.0
1952	367.7	2,456.1
1953	389.7	2,571.4
1954	391.1	2,556.9
1955	426.2	2,739.0
1956	450.1	2,797.4
1957	474.9	2,856.3
1958	482.0	2,835.3
1959	522.5	3,031.0
1960	543.3	3,108.7
1961	563.3	3,188.1
1962	605.1	3,383.1
1963	638.6	3,530.4
1964	685.8	3,734.0
1965	743.7	3,976.7
1966	815.0	4,238.9
1967	861.7	4,355.2
1968	942.5	4,569.0
1969	1,019.9	4,712.5
1970	1,075.9	4,722.0
1971	1,167.8	4,877.6
1972	1,282.4	5,134.3
1973	1,428.5	5,424.1
1974	1,548.8	5,396.0
1975	1,688.9	5,385.4
1976	1,877.6	5,675.4
1977	2,086.0	5,937.0
1978	2,356.6	6,267.2
1979	2,632.1	6,466.2
1980	2,862.5	6,450.4
1981	3,211.0	6,617.7
1982	3,345.0	6,491.3
1983	3,638.1	6,792.0
1984	4,040.7	7,285.0
1985	4,346.7	7,593.8
1986	4,590.2	7,860.5
1987	4,870.2	8,132.6
1988	5,252.6	8,474.5
1989	5,657.7	8,786.4
1990	5,979.6	8,955.0
1991	6,174.0	8,948.4
1992	6,539.3	9,266.6
1993	6,878.7	9,521.0
1994	7,308.8	9,905.4
1995	7,664.1	10,174.8
1996	8,100.2	10,561.0
1997	8,608.5	11,034.9
1998	9,089.2	11,525.9
1999	9,660.6	12,065.9
2000	10,284.8	12,559.7
2001	10,621.8	12,682.2
2002	10,977.5	12,908.8
2003	11,510.7	13,271.1
2004	12,274.9	13,773.5
2005	13,093.7	14,234.2
2006	13,855.9	14,613.8
2007	14,477.6	14,873.7
2008	14,718.6	14,830.4
2009	14,418.7	14,418.7
2010	14,964.4	14,783.8
2011	15,517.9	15,020.6
2012	16,163.2	15,369.2
2013	16,768.1	15,710.3
2014	17,420.7	16,089.8

Quarterly

(Seasonally adjusted annual rates)

Quarter	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#
1947q1	243.1	1,934.5	1
1947q2	246.3	1,932.3	2
1947q3	250.1	1,930.3	3
1947q4	260.3	1,960.7	4
1948q1	266.2	1,989.5	5
1948q2	272.9	2,021.9	6
1948q3	279.5	2,033.2	7
1948q4	280.7	2,035.3	8
1949q1	275.4	2,007.5	9
1949q2	271.7	2,000.8	10
1949q3	273.3	2,022.8	11
1949q4	271.0	2,004.7	12
1950q1	281.2	2,084.6	13
1950q2	290.7	2,147.6	14
1950q3	308.5	2,230.4	15
1950q4	320.3	2,273.4	16
1951q1	336.4	2,304.5	17
1951q2	344.5	2,344.5	18
1951q3	351.8	2,392.8	19
1951q4	356.6	2,398.1	20
1952q1	360.2	2,423.5	21
1952q2	361.4	2,428.5	22
1952q3	368.1	2,446.1	23
1952q4	381.2	2,526.4	24
1953q1	388.5	2,573.4	25
1953q2	392.3	2,593.5	26
1953q3	391.7	2,578.9	27
1953q4	386.5	2,539.8	28
1954q1	385.9	2,528.0	29
1954q2	386.7	2,530.7	30
1954q3	391.6	2,559.4	31
1954q4	400.3	2,609.3	32
1955q1	413.8	2,683.8	33
1955q2	422.2	2,727.5	34
1955q3	430.9	2,764.1	35
1955q4	437.8	2,780.8	36
1956q1	440.5	2,770.0	37
1956q2	446.8	2,792.9	38
1956q3	452.0	2,790.6	39
1956q4	461.3	2,836.2	40
1957q1	470.6	2,854.5	41
1957q2	472.8	2,848.2	42
1957q3	480.3	2,875.9	43
1957q4	475.7	2,846.4	44
1958q1	468.4	2,772.7	45
1958q2	472.8	2,790.9	46
1958q3	486.7	2,855.5	47
1958q4	500.4	2,922.3	48
1959q1	511.1	2,976.6	49
1959q2	524.2	3,049.0	50
1959q3	525.2	3,043.1	51
1959q4	529.3	3,055.1	52
1960q1	543.3	3,123.2	53
1960q2	542.7	3,111.3	54
1960q3	546.0	3,119.1	55
1960q4	541.1	3,081.3	56
1961q1	545.9	3,102.3	57
1961q2	557.4	3,159.9	58
1961q3	568.2	3,212.6	59
1961q4	581.6	3,277.7	60
1962q1	595.2	3,336.8	61
1962q2	602.6	3,372.7	62
1962q3	609.6	3,404.8	63
1962q4	613.1	3,418.0	64
1963q1	622.7	3,456.1	65
1963q2	631.8	3,501.1	66
1963q3	645.0	3,569.5	67
1963q4	654.8	3,595.0	68
1964q1	671.1	3,672.7	69
1964q2	680.8	3,716.4	70
1964q3	692.8	3,766.9	71
1964q4	698.4	3,780.2	72
1965q1	719.2	3,873.5	73
1965q2	732.4	3,926.4	74
1965q3	750.2	4,006.2	75
1965q4	773.1	4,100.6	76
1966q1	797.3	4,201.9	77
1966q2	807.2	4,219.1	78
1966q3	820.8	4,249.2	79
1966q4	834.9	4,285.6	80
1967q1	846.0	4,324.9	81
1967q2	851.1	4,328.7	82
1967q3	866.6	4,366.1	83
1967q4	883.2	4,401.2	84
1968q1	911.1	4,490.6	85
1968q2	936.3	4,566.4	86
1968q3	952.3	4,599.3	87
1968q4	970.1	4,619.8	88
1969q1	995.4	4,691.6	89
1969q2	1,011.4	4,706.7	90
1969q3	1,032.0	4,736.1	91
1969q4	1,040.7	4,715.5	92
1970q1	1,053.5	4,707.1	93
1970q2	1,070.1	4,715.4	94
1970q3	1,088.5	4,757.2	95
1970q4	1,091.5	4,708.3	96
1971q1	1,137.8	4,834.3	97
1971q2	1,159.4	4,861.9	98
1971q3	1,180.3	4,900.0	99
1971q4	1,193.6	4,914.3	100
1972q1	1,233.8	5,002.4	101
1972q2	1,270.1	5,118.3	102
1972q3	1,293.8	5,165.4	103
1972q4	1,332.0	5,251.2	104
1973q1	1,380.7	5,380.5	105
1973q2	1,417.6	5,441.5	106
1973q3	1,436.8	5,411.9	107
1973q4	1,479.1	5,462.4	108
1974q1	1,494.7	5,417.0	109
1974q2	1,534.2	5,431.3	110
1974q3	1,563.4	5,378.7	111
1974q4	1,603.0	5,357.2	112
1975q1	1,619.6	5,292.4	113
1975q2	1,656.4	5,333.2	114
1975q3	1,713.8	5,421.4	115
1975q4	1,765.9	5,494.4	116
1976q1	1,824.5	5,618.5	117
1976q2	1,856.9	5,661.0	118
1976q3	1,890.5	5,689.8	119
1976q4	1,938.4	5,732.5	120
1977q1	1,992.5	5,799.2	121
1977q2	2,060.2	5,913.0	122
1977q3	2,122.4	6,017.6	123
1977q4	2,168.7	6,018.2	124
1978q1	2,208.7	6,039.2	125
1978q2	2,336.6	6,274.0	126
1978q3	2,398.9	6,335.3	127
1978q4	2,482.2	6,420.3	128
1979q1	2,531.6	6,433.0	129
1979q2	2,595.9	6,440.8	130
1979q3	2,670.4	6,487.1	131
1979q4	2,730.7	6,503.9	132
1980q1	2,796.5	6,524.9	133
1980q2	2,799.9	6,392.6	134
1980q3	2,860.0	6,382.9	135
1980q4	2,993.5	6,501.2	136
1981q1	3,131.8	6,635.7	137
1981q2	3,167.3	6,587.3	138
1981q3	3,261.2	6,662.9	139
1981q4	3,283.5	6,585.1	140
1982q1	3,273.8	6,475.0	141
1982q2	3,331.3	6,510.2	142
1982q3	3,367.1	6,486.8	143
1982q4	3,407.8	6,493.1	144
1983q1	3,480.3	6,578.2	145
1983q2	3,583.8	6,728.3	146
1983q3	3,692.3	6,860.0	147

1980 through 2014 Q4

Average	5.37%	Nominal
Average	2.74%	Real
1	8.783381	1980
2	8.762896	
3	8.761378	
4	8.779742	
5	8.800219	1981
6	8.792899	
7	8.804310	
8	8.792565	
9	8.775704	1982
10	8.781125	
11	8.777525	
12	8.778495	
13	8.791516	1983
14	8.814078	
15	8.833463	
16	8.853880	
17	8.873552	1984
18	8.890961	
19	8.900753	
20	8.908695	
21	8.918583	1985
22	8.927699	
23	8.943140	
24	8.950611	
25	8.959838	1986
26	8.964414	
27	8.974441	
28	8.979606	
29	8.986572	1987
30	8.997729	
31	9.006754	
32	9.023131	
33	9.028735	1988
34	9.041863	
35	9.047621	
36	9.060784	
37	9.070814	1989
38	9.078647	
39	9.086080	
40	9.088195	
41	9.099085	1990
42	9.102944	
43	9.103189	
44	9.094638	
45	9.089934	1991
46	9.097664	
47	9.102454	
48	9.106800	
49	9.118554	1992
50	9.129510	
51	9.139188	
52	9.149156	
53	9.151026	1993
54	9.156950	
55	9.161812	
56	9.175076	
57	9.184838	1994
58	9.198409	
59	9.204292	
60	9.215577	
61	9.218993	1995
62	9.222476	
63	9.231005	
64	9.238072	
65	9.244616	1996
66	9.261927	
67	9.271134	
68	9.281647	
69	9.289235	1997
70	9.304213	
71	9.316860	
72	9.324588	
73	9.334432	1998
74	9.344084	
75	9.357087	
76	9.373369	
77	9.381323	1999
78	9.389532	
79	9.402043	
80	9.419247	
81	9.422148	2000
82	9.440857	
83	9.442063	
84	9.447726	
85	9.444883	2001
86	9.450168	
87	9.447000	
88	9.449775	
89	9.458941	2002
90	9.464440	
91	9.469299	
92	9.469932	
93	9.475102	2003
94	9.484337	
95	9.500948	
96	9.512569	
97	9.518303	2004
98	9.525604	
99	9.534653	
100	9.543263	
101	9.553866	2005
102	9.559073	
103	9.567441	
104	9.573135	
105	9.585078	2006
106	9.588064	
107	9.588955	
108	9.596752	
109	9.597370	2007
110	9.604994	
111	9.611697	
112	9.615259	
113	9.608412	2008
114	9.613362	
115	9.608553	
116	9.587200	
117	9.573246	2009
118	9.571895	
119	9.575157	
120	9.584789	
121	9.589106	2010
122	9.598720	
123	9.605452	
124	9.611731	
125	9.607861	2011
126	9.615112	
127	9.617211	
128	9.628412	
129	9.633973	2012
130	9.638004	
131	9.644153	
132	9.644309	
133	9.651070	2013
134	9.655449	
135	9.666492	
136	9.675093	
137	9.669770	2014
138	9.680994	
139	9.693112	
140	9.699632	

OLS Regression

Annualized Real LN GPD Q

2.87%

Regression Statistics	
Multiple R	0.988570992
R Square	0.977272606
Adjusted R	0.977107915
Standard E	0.044086238
Observatio	140

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regressior	1	11.53323798	11.53323798	5933.9676	2.7419E-115
Residual	138	0.2682163	0.001943596		
Total	139	11.80145428			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	8.781241805	0.007492035	1172.077033	9.2E-278	8.766427778	8.796055831	8.766427778	8.796055831
X Variable	0.007102075	9.21961E-05	77.03225051	2.74E-115	0.006919776	0.007284375	0.006919776	0.007284375

GDP is an array of expenditure and income data collected by BEA directly and through other government agencies.

www.bea.gov

Note **July 31, 2013, 14th Comprehensive Significant Revision:**
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

This comprehensive revision did not cause a large percentage jump.
The relative difference of actual amounts over time changed little.

1983q4	3,796.1	7,001.5	148
1984q1	3,912.8	7,140.6	149
1984q2	4,015.0	7,266.0	150
1984q3	4,087.4	7,337.5	151
1984q4	4,147.6	7,396.0	152
1985q1	4,237.0	7,469.5	153
1985q2	4,302.3	7,537.9	154
1985q3	4,394.6	7,655.2	155
1985q4	4,453.1	7,712.6	156
1986q1	4,516.3	7,784.1	157
1986q2	4,555.2	7,819.8	158
1986q3	4,619.6	7,898.6	159
1986q4	4,669.4	7,939.5	160
1987q1	4,736.2	7,995.0	161
1987q2	4,821.5	8,084.7	162
1987q3	4,900.5	8,158.0	163
1987q4	5,022.7	8,292.7	164
1988q1	5,090.6	8,339.3	165
1988q2	5,207.7	8,449.5	166
1988q3	5,299.5	8,498.3	167
1988q4	5,412.7	8,610.9	168
1989q1	5,527.4	8,697.7	169
1989q2	5,628.4	8,766.1	170
1989q3	5,711.6	8,831.5	171
1989q4	5,763.4	8,850.2	172
1990q1	5,890.8	8,947.1	173
1990q2	5,974.7	8,981.7	174
1990q3	6,029.5	8,983.9	175
1990q4	6,023.3	8,907.4	176
1991q1	6,054.9	8,865.6	177
1991q2	6,143.6	8,934.4	178
1991q3	6,218.4	8,977.3	179
1991q4	6,279.3	9,016.4	180
1992q1	6,380.8	9,123.0	181
1992q2	6,492.3	9,223.5	182
1992q3	6,586.5	9,313.2	183
1992q4	6,697.6	9,406.5	184
1993q1	6,748.2	9,424.1	185
1993q2	6,829.6	9,480.1	186
1993q3	6,904.2	9,526.3	187
1993q4	7,032.8	9,653.5	188
1994q1	7,136.3	9,748.2	189
1994q2	7,269.8	9,881.4	190
1994q3	7,352.3	9,939.7	191
1994q4	7,476.7	10,052.5	192
1995q1	7,545.3	10,086.9	193
1995q2	7,604.9	10,122.1	194
1995q3	7,706.5	10,208.8	195
1995q4	7,799.5	10,281.2	196
1996q1	7,893.1	10,348.7	197
1996q2	8,061.5	10,529.4	198
1996q3	8,159.0	10,626.8	199
1996q4	8,287.1	10,739.1	200
1997q1	8,402.1	10,820.9	201
1997q2	8,551.9	10,984.2	202
1997q3	8,691.8	11,124.0	203
1997q4	8,788.3	11,210.3	204
1998q1	8,889.7	11,321.2	205
1998q2	8,994.7	11,431.0	206
1998q3	9,146.5	11,580.6	207
1998q4	9,325.7	11,770.7	208
1999q1	9,447.1	11,864.7	209
1999q2	9,557.0	11,962.5	210
1999q3	9,712.3	12,113.1	211
1999q4	9,926.1	12,323.3	212
2000q1	10,031.0	12,359.1	213
2000q2	10,278.3	12,592.5	214
2000q3	10,357.4	12,607.7	215
2000q4	10,472.3	12,679.3	216
2001q1	10,508.1	12,643.3	217
2001q2	10,638.4	12,710.3	218
2001q3	10,639.5	12,670.1	219
2001q4	10,701.3	12,705.3	220
2002q1	10,834.4	12,822.3	221
2002q2	10,934.8	12,893.0	222
2002q3	11,037.1	12,955.8	223
2002q4	11,103.8	12,964.0	224
2003q1	11,230.1	13,031.2	225
2003q2	11,370.7	13,152.1	226
2003q3	11,625.1	13,372.4	227
2003q4	11,816.8	13,528.7	228
2004q1	11,988.4	13,606.5	229
2004q2	12,181.4	13,706.2	230
2004q3	12,367.7	13,830.8	231
2004q4	12,562.2	13,950.4	232
2005q1	12,813.7	14,099.1	233
2005q2	12,974.1	14,172.7	234
2005q3	13,205.4	14,291.8	235
2005q4	13,381.6	14,373.4	236
2006q1	13,648.9	14,546.1	237
2006q2	13,799.8	14,589.6	238
2006q3	13,908.5	14,602.6	239
2006q4	14,066.4	14,716.9	240
2007q1	14,233.2	14,726.0	241
2007q2	14,422.3	14,838.7	242
2007q3	14,569.7	14,938.5	243
2007q4	14,685.3	14,991.8	244
2008q1	14,668.4	14,889.5	245
2008q2	14,813.0	14,963.4	246
2008q3	14,843.0	14,891.6	247
2008q4	14,549.9	14,577.0	248
2009q1	14,383.9	14,375.0	249
2009q2	14,340.4	14,355.6	250
2009q3	14,384.1	14,402.5	251
2009q4	14,566.5	14,541.9	252
2010q1	14,681.1	14,604.8	253
2010q2	14,888.6	14,745.9	254
2010q3	15,057.7	14,845.5	255
2010q4	15,230.2	14,939.0	256
2011q1	15,238.4	14,881.3	257
2011q2	15,460.9	14,989.6	258
2011q3	15,587.1	15,021.1	259
2011q4	15,785.3	15,190.3	260
2012q1	15,956.5	15,275.0	261
2012q2	16,094.7	15,336.7	262
2012q3	16,268.9	15,431.3	263
2012q4	16,332.5	15,433.7	264
2013q1	16,502.4	15,538.4	265
2013q2	16,619.2	15,606.6	266
2013q3	16,872.3	15,779.9	267
2013q4	17,078.3	15,916.2	268
2014q1	17,044.0	15,831.7	269
2014q2	17,328.2	16,010.4	270
2014q3	17,599.8	16,205.6	271
2014q4	17,710.7	16,311.6	272

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 206

Staff CAPM Results
(Capital Asset Pricing Model)

Exhibits in Support
Of Opening Testimony

October 16, 2015

1	2	3	4	5	6	7	8	9	10	11	12	13
Natural Gas		VL Gas IOUs										
	AVA UG 288	1	Sensitivity with AGL (Purchase by Southern Co. Pending)									
#	Abbreviated Utility	UG 288 AVA	UG 288 Staff	VL Corporate Name Gas Utility	NYS, NSDQ Ticker	SNL Key	IRS EIN	SEC File	VL Region	VL 8/7/2015 Beta	Yahoo Fin. 8/6/2015 Beta	2015 VL Tax Rate
-	Avista	No	No	**Avista Corporation** (*For reference Purposes Only*)	AVA	4057075	91-0462470	1-3701	West	0.80	0.62	
-	Cascade	No	No	**Cascade Natural Gas Corp.**	MDU	4057112	91-0599090	1-7196	West	N/A	N/A	
1	AGL	Yes	Sensitivity	AGL Resources, Inc.	GAS	4057108	58-2210952	1-14174	East	0.80	0.28	37.5%
2	Atmos	Yes	No	Atmos Energy Corp.	ATO	4057157	75-1743247	1-10042	Central	0.85	0.66	39.5%
3	Laclede	Yes	No	The Laclede Group, Inc.	LG	4002506	74-2976504	1-16681	Central	0.70	0.54	29.0%
4	New Jersey	Yes	No	New Jersey Resources Corp.	NJR	4057128	22-2376465	1-8359	East	0.80	0.92	35.0%
5	NiSource	Yes	No	NiSource Inc.	NI	4057051	35-2108964	1-16189	East	0.85	0.54	37.0%
6	Northwest Natural	Yes	Yes	Northwest Natural Gas Company	NWN	4057132	93-0256722	1-15973	West	0.70	0.73	40.0%
7	Piedmont	Yes	Yes	Piedmont Natural Gas Company, Inc.	PNY	4057136	56-0556998	1-6196	East	0.80	0.68	25.0%
8	South Jersey	Yes	No	South Jersey Industries, Inc.	SJI	4057145	22-1901645	1-6364	East	0.85	1.21	25.0%
9	Southwest Gas	Yes	No	Southwest Gas Corporation	SWX	4041957	88-0085720	1-7850	West	0.85	0.88	35.0%
10	UGI	No	No	UGI Corporation (**Propane Focus / VL**)	UGI	4057537	23-2668356	1-11071	East	0.95	0.79	
11	WGL	Yes	No	WGL Holdings, Inc.	WGL	4007261	52-2210912	1-16163	East	0.80	0.89	30.0%

Staff's Representative CAPM Modeling Results

3.09%	Risk Free Rate as 10 Yr UST as of Jan. 15, 2016
3.83%	Risk Free Rate as 30 Yr UST as of Jan. 15, 2016
4.50%	Ibbotson Market Risk Premium

$R_{AVA} = R_f + Beta*MRP$

			VL	Yahoo Fin.			w 10 Yr Forward UST		w 30 Yr Forward UST	
	Abbreviated		8/7/2015	8/6/2015	UG 288	UG 288	CAPM w VL	CAPM w Yahoo	CAPM w VL	CAPM w Yahoo
#	Utility	Ticker	Beta	Beta	AVA	Staff	Beta	Beta	Beta	Beta
1	AGL	GAS	0.80	0.28	Yes	Sensitivity	6.69%	4.35%	7.43%	5.09%
2	Atmos	ATO	0.85	0.66	Yes	No	6.92%	6.06%	7.66%	6.80%
3	Laclede	LG	0.70	0.54	Yes	No	6.24%	5.52%	6.98%	6.26%
4	New Jersey	NJR	0.80	0.92	Yes	No	6.69%	7.23%	7.43%	7.97%
5	NiSource	NI	0.85	0.54	Yes	No	6.92%	5.52%	7.66%	6.26%
6	Northwest Natural	NWN	0.70	0.73	Yes	Yes	6.24%	6.38%	6.98%	7.12%
7	Piedmont	PNY	0.80	0.68	Yes	Yes	6.69%	6.15%	7.43%	6.89%
8	South Jersey	SJI	0.85	1.21	Yes	No	6.92%	8.54%	7.66%	9.28%
9	Southwest Gas	SWX	0.85	0.88	Yes	No	6.92%	7.05%	7.66%	7.79%
10	UGI	UGI	0.95	0.79	No	No	7.37%	6.65%	8.11%	7.39%
11	WGL	WGL	0.80	0.89	Yes	No	6.69%	7.10%	7.43%	7.84%
						AVA:	6.69%	6.39%	7.43%	7.13%
						Staff w/o AGL:	6.47%	5.95%	7.32%	6.69%
						Staff w AGL:	6.54%	6.26%	7.21%	7.00%

Range From: 5.95% To: 7.43%

Overall Midpoint 6.69%

CAPM Results Interpreted as Required Rate of Return

Avg Tax Rate	2015
Co Peers	34%
Staff Peers w/o AGL	33%
Staff Peers w AGL	34%

Using Company's Filing as High End of Potential Inputs

AVA Proposed (UG 288)			Co. Filing Detail
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50%	5.530%	2.77%
Preferred Stock	0%		0.00%
Common Stock	50%	9.900%	4.95%
	100%		7.72%

High End

ROE ex PreTax CAPM			(LT Debt as Filed)
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50%	5.53%	2.77%
Common Stock	50%	9.33%	4.67%
	100%		7.43%

Low End

ROE ex PreTax CAPM			(LT Debt as Filed)
Component	Percent of Total	Cost	Weighted Average
Long Term Debt	50%	5.53%	2.77%
Common Stock	50%	6.37%	3.18%
	100%		5.95%

PreTax Range of CAPM ROE's

Range of ROEs From 6.37% to 9.33%

Midpoint: 7.85%

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

CONFIDENTIAL
Cost of Long-Term Debt

Exhibits in Support
of Opening Testimony

October 16, 2015

STAFF EXHIBIT 207

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

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CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 208

Southern Co.'s Proposes Acquisition
Of AGL Resources

Exhibits in Support
of Opening Testimony

October 16, 2015

Southern Co. to Buy AGL Resources for $8 Billion

by Cassandra Sweet – WSJ – Aug 25, 2015
Chelsey Dulaney contributed to this article.

Deal will create the second-biggest utility company in U.S. by customers

A Southern Co. facility in Mississippi last year.

Southern Co. agreed **to buy natural-gas utility AGL** Resources Inc. for about **$8 billion**, a move that would **give** the **electricity provider** a big chunk of the fast-growing gas market from New Jersey to Florida.

The acquisition would **double the number of Southern's customers to nine million**, making it the **second-largest utility in the U.S.,** the company said on Monday, and providing it with **new revenue to help offset its rising costs**.

Terms of the deal call for **AGL Resources shareholders to receive $66 in cash** for each share, a **38% premium to AGL's closing price on Friday of $47.86 a share**.

Shares of AGL traded up 28% to $61.41 apiece on Monday, still well below the offer price, while Southern shares dropped 5% to $43.58 amid a broad decline in U.S. stocks.

Both companies' boards of directors have approved the merger, they said.

The deal, valued at $12 billion including debt, is the latest move by a large electric utility to buy exposure to the booming natural gas market. **U.S. demand for electricity is stagnating** – and the **fortunes of coal and nuclear power are faltering** – **but demand for inexpensive natural gas is on the rise** around America.

"Natural gas will play a greater and greater role in primary energy needs," Tom Fanning, Southern's chief executive, said on a conference call. "**Driving this deal are growth opportunities**."

Southern has struggled in recent years with other investments in coal- and nuclear-powered electricity generation projects.

Delays and cost overruns have hit the company as it tries to build **new reactors in Georgia**, as well as a **first-of-its-kind clean-coal power plant in Mississippi**. Southern has tried to get regulators to agree to rate increases in certain areas to help cover soaring costs, but so far its success has been limited.

The merger "should provide a crucial **diversification** away from Southern's headline-grabbing construction projects," said Angie Storozynski, a utility-industry analyst at Macquarie Group.http://quotes.wsj.com/MQBKY

Costs have risen at a Southern project in Waynesboro, Ga., shown in 2014.

Southern's bid for AGL expands its roster of customers and bolsters its **ability to buy low-cost natural gas to supply its own power plants**. Burning gas creates far less air pollution than coal, which also could help meet increasingly strict federal utility-pollution limits.

Southern, based in Atlanta, operates 73 power plants and has 4.4 million retail customers in Georgia, Alabama, Mississippi and Florida. **Last year** the company's power-plant portfolio was **40% coal**-powered, **40% gas**, **16% nuclear** and **4% hydro**electric and other sources, according to Southern's annual report. By 2020, company management hopes as much as 55% of its electricity will be generated from gas if prices stay low, while coal would be reduced to 21%.

The number of coal-fired power plants is widely expected to decline around the U.S. because of tougher air pollution regulations which aim to limit carbon emissions from power plants. Since no new coal plants are likely to be built, and nuclear power has largely fallen out of favor owing to the huge cost of constructing new plants, utilities like Southern are increasingly turning to natural-gas-fired power plants to supply energy needs.

AGL, which also is based in Atlanta, has 4.5 million natural-gas customers in Georgia, Tennessee, New Jersey, Maryland, Florida, Illinois and Virginia. It serves additional customers through a joint venture called **SouthStar Energy Services**.

AGL also operates several gas storage plants and is developing gas pipeline projects, said John Somerhalder II, AGL's chief executive.

One of those projects is a joint venture with Southern rivals Duke Energy Inc. and Dominion Resources.http://quotes.wsj.com/D AGL and Piedmont Natural Gas have joined with Duke and Dominion to build a **$5 billion, 550-mile natural gas pipeline** that will stretch **from West Virginia to Virginia and North Carolina.**

Adding a growing natural gas utility business with increasing revenue to its business could help Southern **offset** some of the **problems** it has faced from two budget-busting projects.

Costs have ballooned at Southern's Georgia Power utility, which is building new nuclear power reactors in Waynesboro, Ga. In Mississippi, Southern's Kemper clean coal project is turning into one of the most expensive fossil fuel plants ever built in the U.S.

In the case of Kemper, the company has had to write down billions of dollars' worth of charges. Regulators are now weighing whether Southern's shareholders or its customers will have to foot future bills.

Southern expects the AGL deal to add to its per-share earnings in the first full year after closing, which is expected in the second half of 2016.

Mergers: Southern Co. Bids for AGL Resources

by Ken *Silverstein, Editor-in-Chief – Public Utilities Fortnightly*
Aug. 25, 2015 – *http://spark.fortnightly.com/fortnightly/mergers-southern-co-bids-agl-resources*

The stock market may be in turmoil but the utility sector seems to know where it is headed – away from coal and into natural gas, and renewables. That trend was underscored by today's announcement that **Southern Company** would be **buying AGL** Resources, the **Atlanta-based natural gas distribution company**.

That deal comes atop a **series of mergers and acquisitions** in the utility sector that have **focused on stable cash flows** and dividends. They are commonly called "YieldCos" and they are mostly centered on the renewable energy industry that receives tax credits and that sells to customers under long term contracts, typically around 15 years. That's according to Price WaterHouse Coopers, which spoke to this reporter by phone before the Southern/AGL deal was announced.

Such YieldCos accounted for about 85 percent of the deal activity last quarter, says Jeremy Fago, PwC's U.S. power and utilities deal leader. "Costs have fallen too but when I think of stable cash flows, it is a focus on the **ability to generate a return**. Renewables is the area where those contracts have been."

Regulated utilities are also hot commodities: **Both Southern and AGL are in Atlanta, with one focused on power generation and transmission and the other on natural gas delivery – complementary businesses**.

As the utility sector transitions from coal to natural gas as a way to reduce air emissions, the deal makes sense – and as Chief Executive Tom Fanning put it, "skating to where the puck may be." That's what he said at the Edison Electric Institute meeting, referring to how Southern would conduct business in the coming years. He repeated that to reporters covering today's merger news, noting that negotiations started on the deal last February.

"**Earnings profile and cash flow** are still a focus," adds PwC's Fago, referring to strategic asset acquisitions, as well as complementary deals and mergers between equals. "We do see investor interest in the regulated utility space. It is both financial and strategic. We expect to see continued activity there."

As for the major proposal just made public, Sou**thern will pay $66 for each share of AGL** (link is external), which is a **premium of 38 percent over AGL's current stock price**. The **deal is valued at $12 billion**.

Georgia Public Utility Commission Chair Chuck Eaton, profiled by the Fortnightly last fall, told the Atlanta Journal Constitution that natural gas is the catalyst – that it is today's preferred fuel because of its cost, abundance and carbon emissions, which are about half that of coal. The commission **must approve the deal**. The **F**ederal **E**nergy **R**egulatory **C**ommission and the **F**ederal **T**rade **C**ommission **must also weigh in**.

Southern's Acquisition of AGL Resources Will Significantly Increase Debt

Michael G. Haggarty, Assoc. Managing Director – Moody's –Aug. 27, 2015

Last Monday, The **Southern Company** (Baa1 negative) said that it had agreed to **acquire AGL Resources**, Inc. (unrated), an **Atlanta-based natural gas distribution company**, for approximately **$8 billion in cash**. The transaction will result in a **significant increase in debt** at the Southern holding company at a time when debt has already been increasing, partly to support funding needs at utility subsidiary Mississippi Power Company (Baa2 negative) and portfolio growth at wholesale power subsidiary Southern Power Company (Baa1 stable).

Although **Southern intends to issue $3 billion of equity to finance the transaction** between now and 2019, **initial debt financing will raise leverage for several years**. The **addition of up to $8 billion of debt at the Southern holding company at the transaction's close will increase parent company debt to $10-$11 billion** (around 25% of consolidated debt) **from less than $3 billion currently** (10% of total consolidated debt), **pressuring cash flow coverage metrics**. Southern's ratio of consolidated cash flow from operations (**CFO**) **pre-working capital to debt** will likely fall to around 15% immediately following the acquisition from 20% currently, a level that would be **weak for its current rating** and compared with most other Baa1-rated utility holding company peers. For these reasons, we changed Southern's rating **outlook** to **negative from stable** when the transaction was announced.

Although AGL provides Southern with regulatory and operational diversity, cash flow coverage metrics will be lower for an extended period as equity is issued over four years. AGL also generates lower financial coverage metrics than Southern currently does, with AGL's ratio of CFO pre-working capital to debt expected to decline to the low- to mid-teens from the mid- to high-teens as it issues debt to fund planned capital investments. The combination of **higher debt and lower cash flow coverage ratios will likely lead to a one-notch downgrade of Southern before the transaction's close**, which Southern estimates will be in the **second half of 2016**.

The AGL acquisition comes while **Southern's risk profile has been increasing** and its **relative position in its current rating has weakened** as a result of **cost increases and schedule delays at the Vogtle new nuclear** plant being built by its largest utility subsidiary, Georgia Power Company (A3 stable). Southern's credit quality has also been pressured by approximately **$2 billion of pre-tax ($1.2 billion after-tax**) **charges taken for unrecoverable costs at the Kemper Integrated Gasification Combined Cycle (IGCC) plant** Mississippi Power is building. Southern is also providing significant liquidity to Mississippi Power through intercompany loans. Finally, Southern has been supporting the expansion of wholesale power subsidiary Southern Power into renewable energy through some parent company debt financing.

Nevertheless, the **acquisition of AGL will significantly increase the scale, scope, and diversity of Southern's predominantly electric generating business by adding one of the largest natural gas local distribution companies in the country**, with seven local distribution companies serving more than 4.5 million customers in seven states. Notably, this includes the Atlanta Gas Light Company in Georgia, AGL's second-largest local distribution company, providing opportunities for some synergies and cost savings with Georgia Power. The acquisition would also help re**duce Southern's concentration risk** associated with the large Vogtle and Kemper construction projects because the **combined organization would be larger and more diverse**.

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 209

Value Line (VL)
Gas and Water Utility Profiles

Exhibits in Support
of Opening Testimony

October 16, 2015

NATURAL GAS UTILITY

Stocks within *Value Line's* Natural Gas Utility Industry have had to contend with very volatile financial markets of late. One driving force is China, given that its economy (the second largest in the world behind the United States) is showing indications of losing steam. To make matters worse, there are lingering concerns about oil prices that, at the time of this writing, dropped to their lowest level in several years. But investor anxiety has lessened, to a certain extent, by the Chinese central bank's sudden decision to, once again, lower interest rates to promote economic activity. Moreover, looking at the United States, there were some favorable recent statistics for new home sales, and consumer confidence has improved, both of which suggest that the economic recovery is on track. During all this market turbulence, which seems to occur more often these days, shares in the Natural Gas Utility group are holding up better than many of those in other sectors. One key reason for this is their generous levels of dividend income, which tend to provide a measure of much-needed stability.

Natural Gas Prices

Natural gas quotations have been relatively low for some time, and it appears that these trends will continue. Even so, that scenario is generally good for regulated utility operations, in part, because it ought to lead to diminished prices for customers, thus bringing down bad-debt expense. Furthermore, there is an increased possibility that homeowners will switch from alternative fuel sources, such as propane, to natural gas. (At the present time, it's estimated that more than 50% of all households in the United States use natural gas.) It is important to mention, nevertheless, that companies in our category also possess nonregulated businesses, which tend to underperform when gas prices are in a slump. Companies with some exposure to this arena include *New Jersey Resources, WGL Holdings, Atmos Energy, AGL Resources,* and *South Jersey Industries.*

Rate Filings

A number of these utilities must settle cases with their respective state commissions when attempting to change their current rates. The local governments evaluate those rates and determine the return on equity these companies can achieve for a certain period of time. Rate cases generally occur when operational expenses pressure profitability. Thus, at any given time, there are usually several rate cases pending here. As a result, the status of rate cases remains carefully watched in this sector. A favorable ruling can increase what a company might charge customers and, in turn, bolster earnings. It's worth mentioning that, during the first nine months of fiscal 2015 (ends September 30th), *Atmos Energy* managed to complete 15 rate-case proceedings, resulting in a $75.9 million rise in annual operating income. The state commissions generally try to strike a balance between consumer and shareholder interests in making decisions. When the regulatory environment is relatively quiet, utilities might place greater emphasis on expense-reduction initiatives and nonregulated businesses (which include pipelines and energy marketing & trading).

INDUSTRY TIMELINESS: 65 (of 96)

Attractive Dividends

The main feature of utility equities is their dividend income. At the time of this writing, the average yield for the 12 companies in our universe was about 3.4%, significantly higher than the *Value Line* median of 2.4%. Standouts include *NiSource Inc., Northwest Natural Gas, Laclede Group, Piedmont Natural Gas,* and *South Jersey Industries.* When the financial markets exhibit greater volatility, healthy dividend yields tend to act like an anchor, so to speak.

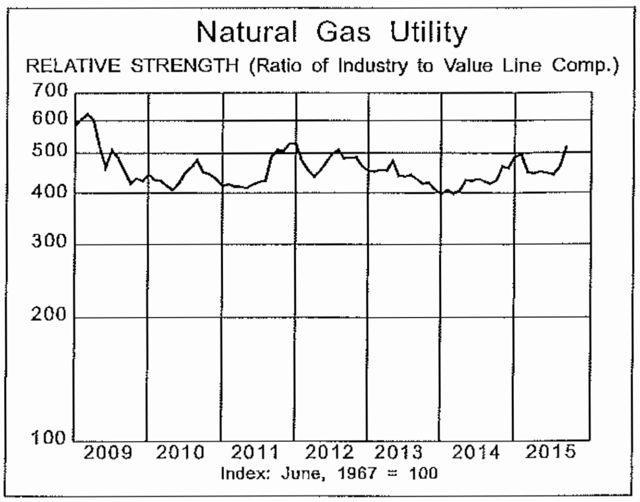
Business Prospects Out To 2018-2020

We are generally optimistic about the sector's operating performance over the long haul. Indeed, natural gas should remain abundant in this country, thanks to new technologies, so a shortage does not appear likely anytime soon. Moreover, there are limited alternatives for the services the companies in our group offer. Also, it's a challenge for new entrants in the market, given such factors as the size of existing competitors and the considerable initial capital outlays that are required. Finally, the nation's population (over 320 million right now) ought to continue on a steady, upward course, which augurs well for future demand for utility services.

Conclusion

Stocks within the Natural Gas Utility Industry ought to draw the attention of income-hungry investors with a conservative orientation (given that a number of these issues are ranked favorably for Safety and boast high grades for Price Stability). It is important to note that companies possessing larger nonregulated operations might well offer a higher potential for returns, but profits could be more volatile than for companies with a greater emphasis on the more stable utility segment. As always, our readers are advised to carefully examine the following reports before making a commitment.

Frederick L. Harris, III

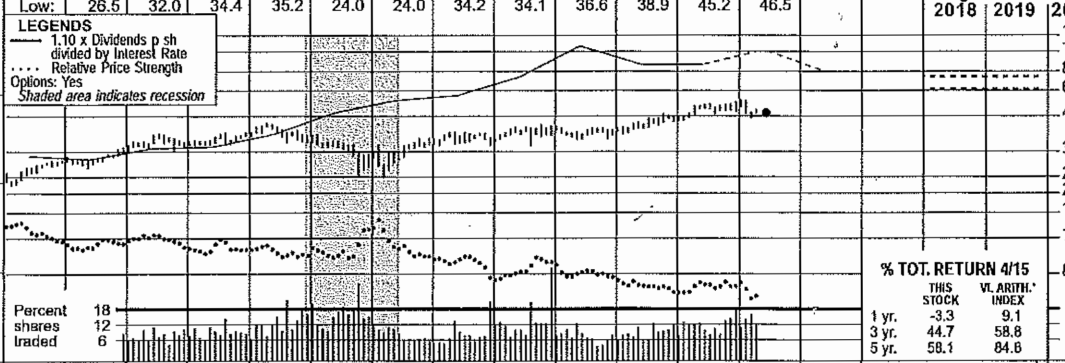


AGL RESOURCES NYSE-GAS

RECENT PRICE 49.56 | P/E RATIO 16.0 (Trailing: 14.0 Median: 14.0) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Lowered 12/26/14
SAFETY 1 Raised 9/9/11
TECHNICAL 5 Lowered 6/5/15
BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9	49.3	56.7	57.8
Low:	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6	38.9	45.2	46.5



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+50%)	14%
Low	65	(+30%)	10%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	1	1	1	1	1	1	1	2

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	216	201	205
to Sell	162	196	201
Hld's(000)	78232	79006	77255

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.3	9.1
3 yr.	44.7	58.8
5 yr.	58.1	84.8

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	19.97	33.28	38.83	45.01	37.90	41.95	Revenues per sh A	48.80
2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.06	5.82	6.15	7.87	6.75	7.55	"Cash Flow" per sh	9.30
.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	2.31	2.64	4.71	3.10	3.35	Earnings per sh A B	4.65
1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	1.90	1.74	1.88	1.96	2.04	2.10	Div'ds Decl'd per sh CF■	2.40
2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.65	6.64	6.30	6.43	6.75	7.25	Cap'l Spending per sh	7.20
11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.33	28.96	30.54	31.63	33.15	34.20	Book Value per sh D	36.65
57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.10	117.86	118.89	119.65	122.00	124.00	Common Shs Outst'g E	125.00
21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	18.8	17.2	16.7	11.0	Bold figures are		Avg Ann'l P/E Ratio	15.0
1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	1.18	1.09	.94	.58	Value Line		Relative P/E Ratio	.95
5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	4.4%	4.3%	3.8%	estimates		Avg Ann'l Div'd Yield	3.4%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $4711 mill. Due in 5 Yrs $2764 mill.
LT Debt $3524 mill. LT Interest $181 mill.
(Total interest coverage: 4.9x)

Leases, Uncapitalized Annual rentals $33 mill.
Pension Assets-12/14 $906 mill.
Oblig. $1098 mill.

Pfd Stock None

Common Stock 119,934,611 shs.
as of 4/23/15
MARKET CAP: $5.9 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	3922.0	4617.0	5385.0	4500	5200	Revenues ($mill) A	6100
193.0	212.0	211.0	207.6	222.0	234.0	172.0	271.0	313.0	562.0	450	520	Net Profit ($mill)	580
37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	36.4%	36.6%	37.6%	37.5%	38.0%	Income Tax Rate	32.5%
7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	6.9%	6.8%	10.4%	8.4%	8.0%	Net Profit Margin	9.5%
51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	51.8%	49.4%	51.2%	48.8%	48.0%	48.5%	Long-Term Debt Ratio	50.0%
48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.2%	50.6%	48.8%	51.2%	52.0%	51.5%	Common Equity Ratio	50.0%
3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	6879.0	6740.0	7444.0	7386.0	7830	8210	Total Capital ($mill)	9175
3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	8347.0	8781.0	9090.0	9635	10215	Net Plant ($mill)	12165
7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.1%	5.4%	5.4%	8.8%	6.5%	6.5%	Return on Total Cap'l	8.0%
12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	7.9%	8.6%	14.9%	9.0%	10.0%	Return on Shr. Equity	12.5%
12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	7.9%	8.6%	14.9%	9.0%	10.0%	Return on Com Equity	12.5%
6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	2.0%	2.5%	8.7%	3.0%	3.5%	Retained to Com Eq	6.5%
52%	52%	58%	60%	57%	57%	86%	75%	71%	41%	66%	62%	All Div'ds to Net Prof	52%

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	105	32	41
Other	2628	2858	2038
Current Assets	2733	2890	2079
Accts Payable	432	312	285
Debt Due	1842	2152	1187
Other	848	755	899
Current Liab.	3122	3219	2371
Fix. Chg. Cov.	373%	612%	488%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	8.0%	3.5%	4.0%
"Cash Flow"	7.0%	7.0%	6.0%
Earnings	4.5%	3.0%	6.5%
Dividends	5.5%	2.0%	4.5%
Book Value	7.5%	6.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1404	686	614	1218	3922
2013	1709	904	675	1329	4617
2014	2462	889	589	1445	5385
2015	1721	780	599	1400	4500
2016	2150	850	650	1550	5200

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1.12	.28	.08	.84	2.31
2013	1.31	.41	.24	.68	2.64
2014	2.81	.48	.19	1.24	4.71
2015	1.62	.30	.20	.98	3.10
2016	1.75	.35	.25	1.00	3.35

Cal-endar	QUARTERLY DIVIDENDS PAID CF■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.45	.45	.45	.55	1.90
2012	.36	.46	.46	.46	1.74
2013	.47	.47	.47	.47	1.88
2014	.49	.49	.49	.49	1.96
2015	.51	.51			

BUSINESS: AGL Resources Inc. is a public utility holding company. Distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Virginia Natural Gas, Florida City Gas and Elkton Gas. Acquired Nicor in 2011. The utilities have more than 4.5 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Illinois. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. BlackRock Inc. owns 8.0% of common stock; officers/directors, less than 1.0% (3/15 Proxy). President & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources reported lackluster first-quarter results. Despite decent operations across the utility segment, earnings per share of $1.62 underperformed our expectations, as the wholesale services segment had a significant downturn in profitability. Though last year's record profit looked poised to fall in 2015, the quarterly outcome was worse than we had projected. Thus, we have lowered our 2015 estimate by $0.65 a share, to $3.10.

The rest of the year should have respectable results. Increased customer growth and accelerating rider programs should allow for decent results in the utility segment, and the company is filing rates cases for additional revenues. Indeed, AGL is asking for an additional $10 million annually in Florida City, and it submitted a request to recover $178 million in Georgia. Rate relief should boost profitability, if approved.

The company's pipeline investments should pay off over the long haul. Indeed, the pipelines lower the cost of transporting natural gas to the Georgia, New Jersey, and Virginia coverage areas, and have higher allowable return rates. This ought to increase earnings by around $0.20 annually, once the projects are put into service in the 2017-2018 time frame. Too, we expect they will allow for less earnings volatility.

The balance sheet is in solid condition. Debt-to-equity has trended lower in recent years. However, the debt-equity ratio may be near a low point, as management plans to relever AGL to fuel capital expenditures, including an anticipated $300 million bond issuance this fall. Cash flows remain solid and should fuel the payout over the coming years. AGL Resources could be in the market for an acquisition.

Shares of AGL Resources are attractive for several reasons. Despite being only neutrally ranked for Timeliness, this issue holds above-average total return potential for a utility. Too, it delivers a strong current payout, and has decent dividend growth potential. This issue should appeal to risk-averse investors, as it carries our Highest Safety mark (1). All told, most long-term investors should find this issue to be appealing.

John E. Seibert III *June 5, 2015*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. May not add up due to rounding. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13; '14, ($0.67). Next earnings report due late July.(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2014: $1,952 million, $16.38/share.(E) In millions. (F) Excluding special dividends from the Nicor merger.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	60

ATMOS ENERGY CORP. NYSE-ATO

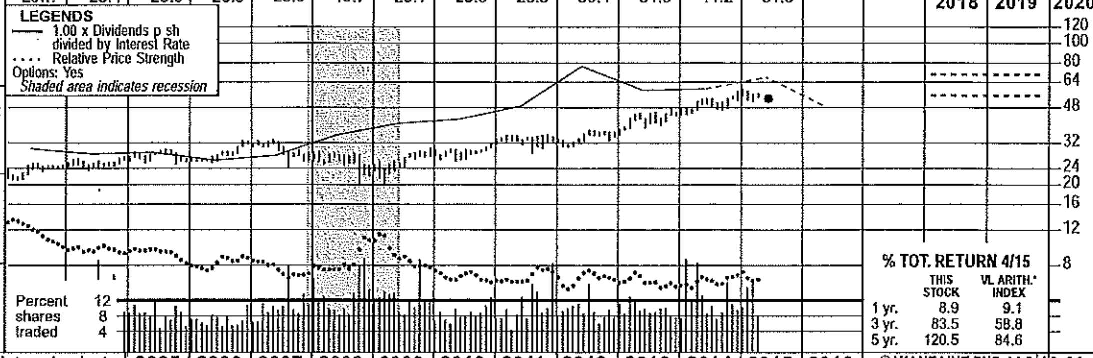
RECENT PRICE 53.20 | P/E RATIO 17.5 (Trailing: 17.8 / Median: 15.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Raised 3/13/15
SAFETY 1 Raised 6/6/14
TECHNICAL 4 Lowered 5/22/15
BETA .85 (1.00 = Market)

High:	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3	47.4	58.2	59.3
Low:	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4	34.9	44.2	51.3

Target Price Range 2018 | 2019 | 2020

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+30%)	*10%*
Low	55	(+5%)	*4%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	1	1	0	1	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	128	141	133
to Sell	139	120	142
Hld's(000)	69353	69403	68718

Percent shares traded 12 8 4

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.9	9.1
3 yr.	83.5	58.8
5 yr.	120.5	84.6

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
61.75	75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	*43.15*	*46.35*	Revenues per sh A	*54.15*
3.90	4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	*5.55*	*5.75*	"Cash Flow" per sh	*6.60*
1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	*3.00*	*3.20*	Earnings per sh A B	*3.80*
1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	*1.56*	*1.64*	Div'ds Decl'd per sh C■	*1.90*
4.14	5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	*9.05*	*8.90*	Cap'l Spending per sh	*9.40*
19.90	20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	*31.85*	*32.70*	Book Value per sh	*36.65*
80.54	81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	*105.00*	*110.00*	Common Shs Outst'g D	*120.00*
16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
.86	.73	.84	.82	.83	.84	.90	1.01	.89	.84	*Value Line*		Relative P/E Ratio	*1.05*
4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*
4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	3886.3	4940.9	*4530*	*5100*	Revenues ($mill) A	*6500*
135.8	162.3	170.5	180.3	179.7	201.2	199.3	192.2	230.7	289.8	*315*	*350*	Net Profit ($mill)	*460*
37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	38.2%	39.2%	*39.5%*	*39.5%*	Income Tax Rate	*40.0%*
2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	5.9%	5.9%	*7.0%*	*6.9%*	Net Profit Margin	*7.1%*
57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	45.3%	48.8%	44.3%	*44.5%*	*45.0%*	Long-Term Debt Ratio	*45.0%*
42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	54.7%	51.2%	55.7%	*55.5%*	*55.0%*	Common Equity Ratio	*55.0%*
3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	4315.5	5036.1	5542.2	*6030*	*6540*	Total Capital ($mill)	*8000*
3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	5475.6	6030.7	6725.9	*7500*	*8100*	Net Plant ($mill)	*10200*
5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	6.1%	5.9%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	2.8%	4.0%	4.7%	*4.5%*	*4.5%*	Retained to Com Eq	*5.5%*
73%	63%	65%	65%	68%	62%	62%	65%	56%	51%	*52%*	*52%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $2680.2 mill. Due in 5 Yrs $950.0 mill.
LT Debt $2455.2 mill. LT Interest $145.0 mill.
(LT interest earned: 4.7x; total interest coverage: 4.7x)
Leases, Uncapitalized Annual rentals $16.7 mill.
Pfd Stock None
Pension Assets-9/14 $434.8 mill. Oblig. $493.6 mill.
Common Stock 101,018,788 shs. as of 5/1/15
MARKET CAP: $5.4 billion (Large Cap)

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	66.2	42.3	95.5
Other	617.1	733.5	722.1
Current Assets	683.3	775.8	817.6
Accts Payable	241.6	311.6	295.6
Debt Due	368.0	196.7	225.0
Other	368.9	402.4	497.9
Current Liab.	978.5	910.7	1018.5
Fix. Chg. Cov.	537%	637%	645%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-8.0%	*4.0%*
"Cash Flow"	5.0%	4.0%	*4.5%*
Earnings	5.0%	5.0%	*7.0%*
Dividends	1.5%	2.0%	*5.0%*
Book Value	6.0%	4.5%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	1084.0	1225.5	576.4	552.6	3438.5
2013	1034.2	1309.0	857.9	685.2	3886.3
2014	1255.1	1964.3	942.7	778.8	4940.9
2015	1258.8	1540.1	*955*	*776.1*	*4530*
2016	*1300*	*2000*	*1000*	*800*	*5100*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	.68	1.12	.31	--	2.10
2013	.85	1.23	.36	.08	2.50
2014	.95	1.38	.45	.23	2.96
2015	.96	1.35	*.47*	*.22*	*3.00*
2016	*1.00*	*1.45*	*.51*	*.24*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.34	.34	.34	.345	1.37
2012	.345	.345	.345	.35	1.39
2013	.35	.35	.35	.37	1.42
2014	.37	.37	.37	.39	1.50
2015	.39	.39			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to more than three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for 2014: 65%, residential; 30%, commercial; 3%, industrial; and 2% other. 2014 depreciation rate 3.0%. Has around 4,760 employees. Officers and directors own 1.6% of common stock (12/14 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy had a tough time making progress on the earnings-per-share front in the first two quarters of fiscal 2015. (Years end on September 30th.) The nonregulated segment experienced a drop in realized margins, reflecting lower natural gas price volatility. During the same period in fiscal 2014, strong demand in the natural gas market caused by substantially colder-than-normal weather led to a more attractive business environment. It should also be noted that the weighted number of diluted shares outstanding was higher. But the natural gas distribution unit benefited partly from higher rates, particularly in the Mid-Tex, Kentucky/Mid-States, Colorado-Kansas, and West Texas divisions. Greater transportation revenues and higher revenue-related taxes helped here, too. Finally, the performance of the regulated pipeline operation enjoyed the benefits of the Gas Reliability Infrastructure Program (GRIP) filings approved in 2014 and 2015.

We anticipate more of the same during the second half. Consequently, the bottom line might be about $3.00 a share for the year as a whole. That would be slightly above the fiscal 2014 figure. Regarding fiscal 2016, however, share net may advance to $3.20, assuming that operating margins expand further.

Meanwhile, there has been much activity in the rate-filing arena. In fact, through the first six months of this fiscal year, the Dallas-headquartered company completed seven regulatory proceedings resulting in a $14.4 million increase in annual operating income. What's more, at the time of this writing, there were 10 rate-making initiatives in progress seeking an additional $114.4 million of annual operating income. Of course, there are no guarantees that Atmos will receive everything it desires.

Various investors should find something to like here. The equity offers a decent amount of current dividend income that's well covered by corporate profits. Future, steady increases in the payout are probable, also. Moreover, the Timeliness rank sits at 2 (Above Average). Other appealing qualities include the 1 (Highest) rank for Safety and excellent score for Price Stability.

Frederick L. Harris, III *June 5, 2015*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢. Next egs. rpt. due early Aug. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	90

LACLEDE GROUP NYSE-LG

RECENT PRICE 52.49 | P/E RATIO 16.4 (Trailing: 16.2; Median: 14.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Raised 2/27/15
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Lowered 5/22/15
BETA .70 (1.00 = Market)

High:	32.5	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0	48.5	55.2	55.8
Low:	26.0	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5	37.4	44.0	49.1

2018-20 PROJECTIONS

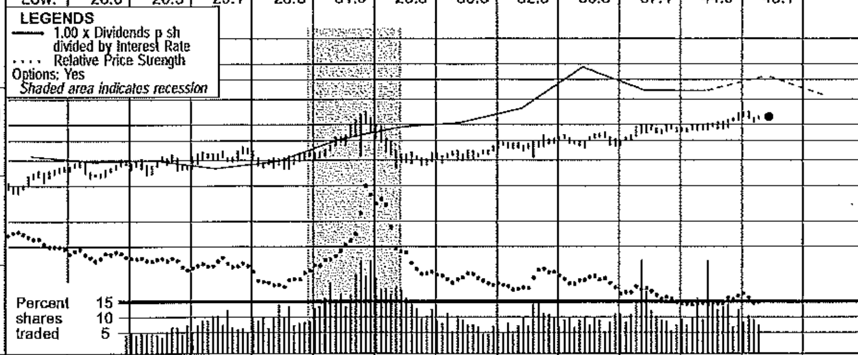
	Price	Gain	Ann'l Total Return
High	75	(+45%)	12%
Low	55	(+5%)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	2	0	0	0	0	0	0
to Sell	0	2	2	0	0	0	0	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	125	113	85
to Sell	53	67	99
Hld's(000)	32190	34204	34804



Target Price Range 2018 | 2019 | 2020
128
96
80
64
48
40
32
24
16
12

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.6	9.1
3 yr.	48.1	58.8
5 yr.	86.9	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	*51.15*	*55.80*	Revenues per sh A	*60.00*
2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	*5.00*	*5.30*	"Cash Flow" per sh	*6.35*
1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	*3.15*	*3.30*	Earnings per sh A B	*4.20*
1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	*1.84*	*1.92*	Div'ds Decl'd per sh C ■	*2.20*
2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	*4.20*	*4.40*	Cap'l Spending per sh	*5.55*
14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	*36.20*	*39.80*	Book Value per sh D	*48.10*
18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	*43.00*	*43.00*	Common Shs Outst'g E	*45.00*
15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	*Value Line*		Relative P/E Ratio	*.95*
5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
						1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	1017.0	1627.2	*2200*	*2400*	Revenues ($mill) A	*2700*
						40.1	50.5	49.8	57.6	64.3	54.0	63.8	62.6	52.8	84.6	*135*	*140*	Net Profit ($mill)	*190*
						34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	29.6%	25.0%	27.6%	*29.0%*	*30.0%*	Income Tax Rate	*30.0%*
						2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	5.2%	5.2%	*6.2%*	*5.9%*	Net Profit Margin	*7.0%*
						48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.1%	46.6%	55.1%	*54.0%*	*53.0%*	Long-Term Debt Ratio	*51.0%*
						51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	63.9%	53.4%	44.9%	*46.0%*	*47.0%*	Common Equity Ratio	*49.0%*
						707.9	798.9	784.5	876.1	906.3	899.9	937.7	941.0	1959.0	3359.4	*3400*	*3645*	Total Capital ($mill)	*4400*
						679.5	763.8	793.8	823.2	855.9	884.1	928.7	1019.3	1776.6	2759.7	*2895*	*3045*	Net Plant ($mill)	*3520*
						7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	7.9%	3.3%	3.1%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
						10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	*8.5%*	*8.5%*	Return on Shr. Equity	*8.5%*
						10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	*8.5%*	*8.5%*	Return on Com Equity	*8.5%*
						3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	1.0%	1.5%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
						72%	59%	63%	56%	53%	64%	56%	59%	81%	73%	*58%*	*58%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $2063.9 mill. Due in 5 Yrs $100.0 mill.
LT Debt $1736.3 mill. LT Interest $70.0 mill.
(Total interest coverage: 4.7x)

Leases, Uncapitalized Annual rentals $12.0 mill.
Pension Assets-9/14 $506.6 mill. Oblig. $692.5 mill.

Pfd Stock None
Common Stock 43,318,933 shs. as of 4/30/15

MARKET CAP: $2.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	53.0	16.1	46.9
Other	422.9	588.8	790.3
Current Assets	475.9	604.9	837.2
Accts Payable	140.2	176.7	247.6
Debt Due	74.0	287.1	327.6
Other	139.0	319.0	278.5
Current Liab.	353.2	782.8	853.7
Fix. Chg. Cov.	337%	423%	477%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-2.5%	-15.5%	*7.0%*
"Cash Flow"	3.0%	-2.0%	*8.5%*
Earnings	4.0%	-2.0%	*10.0%*
Dividends	2.5%	3.0%	*4.5%*
Book Value	7.0%	7.5%	*7.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	410.9	358.2	186.9	169.5	1125.5
2013	307.0	397.6	165.3	147.1	1017.0
2014	468.6	694.5	241.8	222.3	1627.2
2015	619.6	877.4	*360*	*343*	*2200*
2016	*675*	*950*	*400*	*375*	*2400*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	1.12	1.32	.38	d.03	2.79
2013	1.14	1.34	.25	d.30	2.02
2014	1.09	1.59	.33	d.35	2.35
2015	1.09	2.18	*.20*	*d.32*	*3.15*
2016	*1.15*	*1.90*	*.30*	*d.25*	*3.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.405	.405	.405	.405	1.62
2012	.415	.415	.415	.415	1.66
2013	.425	.425	.425	.425	1.70
2014	.44	.44	.44	.44	1.76
2015	.46	.46			

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes netural gas across Missouri, including the cities of St. Louis and Kansas City. Has roughly 1.6 million customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Acquired Missourri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2014: 2.0 bill. Revenue mix for regulated operations: residential, 66%; commercial and industrial, 24%; transportation, 2%; other, 8%. Has around 3,152 employees. Officers and directors own 3.2% of common shares (1/15 proxy). Chairman: William E. Nasser; CEO: Suzanne Silherwood. Inc.: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede reported solid fiscal second-quarter results (ended March 31st). Indeed, earnings per share reached $2.18, aided by contributions from the Alagasco merger and synergies being realized through combination efforts with Missouri Gas. Too, cooler-than-usual winter weather played a role in the outstanding results. The second half of the fiscal year appears likely to be weaker than our original projections, as a warmer April and the timing of expenses, including increased maintenance costs, should hamper second-half results. Still, given the latest performance, we raised our 2015 share-net estimate by a nickel, to $3.15.

The longer-term picture is favorable for Laclede. Rates cases have been filed for an increase in infrastructure replacement, including $5.5 million at Laclede and $2.9 million at Missouri Gas. This should lead to decent earnings growth, as the company would benefit from increased pipeline reliability. The integration of Alagasco appears to be on the right track, and further synergies look to be achieved going forward. All told, we think Laclede can earn $4.20 a share by 2018-2020.

Finances appear to be in decent shape. Although like many industry peers, Laclede's long-term debt constitutes more than 50% of total capital, this is at a fairly manageble level. Too, a good portion of the debt is fixed-rate, which means interest expenses don't fluctuate much. This, in turn, helps to add some stability to earnings.

The dividend is a top draw. The payout is well covered by earnings, and the yield is attractive. We expect the dividend to rise at a decent clip over the next few years, although the payout ratio will likely be well below historical highs.

This issue has moderate appeal at this time. Indeed, long-term appreciation potential is below average, and the prospects for payout growth are modest. Nonetheless, when factoring the Above-Average Safety rank and a lower-than-market Beta, Laclede shares offer reasonable total return possibilities on a risk-adjusted basis. This issue should appeal to those with an income objective, though waiting for a price dip appears to be prudent at this juncture.

John E. Seibert III *June 5, 2015*

(A) Fiscal yaar ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '14: $383.8 mill., $8.85/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	85

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 29.84 | P/E RATIO 17.0 (Trailing: 18.3 Median: 16.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 10/31/14
SAFETY 1 Raised 9/15/06
TECHNICAL 4 Lowered 5/22/15
BETA .80 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(Nil)	3%
Low	25	(-15%)	-1%

Insider Decisions

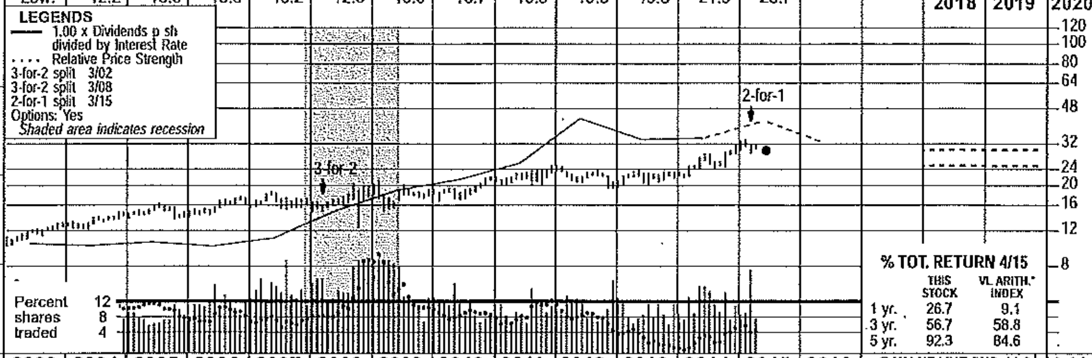
	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	6	0	2	0	0	0
to Sell	0	0	0	0	0	3	0	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	117	92	107
to Sell	80	112	99
Hld's(000)	52088	50964	51530

High:	14.9	16.4	17.7	18.8	20.6	21.2	22.0	25.2	25.1	23.8	32.1	33.7
Low:	12.2	13.6	13.8	15.2	12.3	15.0	16.7	19.8	19.3	19.5	21.9	28.7

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/02
3-for-2 split 3/08
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.7	9.1
3 yr.	56.7	58.8
5 yr.	92.3	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
11.33	14.71	25.61	22.06	31.14	30.44	38.10	39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	*40.60*	*41.75*	Revenues per sh A	*45.65*
.93	1.00	1.06	1.07	1.19	1.25	1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	*2.20*	*2.50*	"Cash Flow" per sh	*2.65*
.55	.60	.65	.70	.79	.85	.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.10	*1.75*	*1.80*	Earnings per sh B	*1.85*
.37	.38	.39	.40	.41	.43	.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	*.92*	*.94*	Div'ds Decl'd per sh C ■	*.98*
.60	.62	.55	.51	.57	.72	.64	.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	*.95*	*.95*	Cap'l Spending per sh	*.95*
3.79	4.14	4.40	4.35	5.13	5.62	5.30	7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.47	*12.30*	*13.20*	Book Value per sh D	*15.65*
79.83	79.17	79.99	83.00	81.70	83.22	82.64	82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	*85.00*	*85.00*	Common Shs Outst'g E	*85.00*
15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.6	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.60	*Value Line*		Relative P/E Ratio	*.90*
4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
						3148.3	3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	3198.1	3738.2	*3450*	*3550*	Revenues ($mill) A	*3940*
						74.4	78.5	65.3	113.9	101.0	101.8	106.5	112.4	113.7	176.9	*135*	*155*	Net Profit ($mill)	*155*
						39.1%	38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	7.1%	25.4%	35.0%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						2.4%	2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	5.0%	3.6%	4.7%	*4.0%*	*4.0%*	Net Profit Margin	*4.0%*
						42.0%	34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	36.6%	38.2%	*32.5%*	*31.0%*	Long-Term Debt Ratio	*27.5%*
						58.0%	65.2%	62.7%	61.5%	60.2%	62.8%	64.5%	60.8%	63.4%	61.8%	*67.5%*	*69.0%*	Common Equity Ratio	*72.5%*
						755.3	954.0	1028.0	1182.1	1144.8	1154.4	1203.1	1339.0	1400.3	1564.4	*1545*	*1620*	Total Capital ($mill)	*1830*
						905.1	934.9	970.9	1017.3	1064.4	1135.7	1295.9	1484.9	1643.1	1884.1	*1920*	*1960*	Net Plant ($mill)	*2080*
						11.2%	9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	9.2%	9.0%	12.5%	*9.5%*	*10.5%*	Return on Total Cap'l	*9.5%*
						17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	*12.5%*	*13.5%*	Return on Shr. Equity	*12.0%*
						17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	*12.5%*	*13.5%*	Return on Com Equity	*12.0%*
						8.5%	6.3%	3.6%	9.5%	7.2%	6.7%	6.2%	6.2%	5.2%	11.0%	*5.5%*	*7.0%*	Retained to Com Eq	*5.5%*
						50%	50%	64%	40%	50%	52%	55%	55%	59%	40%	*59%*	*52%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $881.5 mill. Due in 5 Yrs $315.2 mill.
LT Debt $699.2 mill. LT Interest $16.3 mill.
Incl. $57.9 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/14 $268.6 mill. Oblig. $355.5 mill.

Pfd Stock None

Common Stock 85,581,223 shs. as of 5/5/15
MARKET CAP: $2.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	3.0	2.2	103.3
Other	742.9	680.5	642.3
Current Assets	745.9	682.7	745.6
Accts Peyable	332.8	330.3	329.5
Debt Due	434.2	335.5	182.3
Other	84.8	125.3	143.3
Current Liab.	851.8	791.1	655.1
Fix. Chg. Cov.	700%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	2.5%	-3.5%	*3.5%*
"Cash Flow"	5.0%	4.5%	*3.5%*
Earnings	6.5%	5.5%	*2.5%*
Dividends	6.5%	8.5%	*3.0%*
Book Value	8.0%	4.5%	*6.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	642.4	612.9	425.1	568.5	2248.9
2013	736.0	960.9	767.5	733.7	3198.1
2014	878.4	1579.6	688.3	591.9	3738.2
2015	824.1	1013.1	*825*	*787.8*	*3450*
2016	*850*	*1060*	*835*	*805*	*3550*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	.55	.90	.05	d.14	1.36
2013	.43	.82	.12	d.01	1.37
2014	.47	1.81	.05	d.23	2.10
2015	.65	1.16	*.10*	*d.16*	*1.75*
2016	*.66*	*1.17*	*.11*	*d.14*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.18	.18	.18	.18	.72
2012	.19	.19	.19	.40	.97
2013	--	.20	.20	.20	.60
2014	.21	.21	.21	.23	.86
2015	.23	.23			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 504,300 customers at 9/30/14 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2014 volume: 260 bill. cu. ft. (4% interruptible, 27% residential and commercial and electric utility, 69% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2014 dep. rate: 3.0%. Has 968 empls. Off./dir. own about 1.4% of common (12/14 Proxy). Chrmn., CEO & Pres.: Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources posted mixed financial results for its March quarter. Indeed, revenues declined almost 36%, on a year-to-year basis. This downturn reflected a 46.1% drop in the nonutility business, and to a lesser extent a 5% fall in utility volumes. On the upside, the majority of the reduced revenues are stemming from the downturn in commodity fuel prices. This is evident in NJR's system throughput, which increased 21%, to 297.8 billion cubic feet. On the profitability front, the diminished top line weighed on both fixed- and variable-cost absorption and, consequently, operating expenses rose 740 basis points as a percentage of revenues. After excluding losses on derivative instruments, tax adjustments, and the effect of economic hedging, the company's net financial earnings declined about 36%, to $1.16 a share. This was better than our earlier expectation.

As a result, we have raised our 2015 bottom-line estimate by $0.20, to $1.75 a share. This would still represent an annual earnings decline of more than 15%. Nonetheless, it does fall more in line with management's recently raised guidance range of $1.65-$1.75. The main detractor to this year's results will likely be lower energy services income. That said, NJR continues to benefit from the New Jersey Natural Gas division, which added 4,079 new customer accounts so far this year; about half of those came from newly constructed homes in its service territory. The company anticipates adding 15,000-17,000 new accounts in 2015 and 2016, combined.

Capital expenditures augur well for New Jersey Resources' prospects. It continues to focus on updating its regulated utility infrastructure, in an effort to raise system safety, reliability, and integrity. The Southern Reliability Link is a 28-mile, 30-inch main transmission pipeline that is in the planning and approval phase. Finally, the company recently completed its 20mw Carroll Area Wind Farm, and continues to work on the 48mw Alexander Wind Farm in Kansas. All told, these projects represent about $500 million-$600 million in capital projects.

Still, at this juncture, these shares do not stand out. NJR's dividend yield is below average for a utility.

Bryan J. Fong *June 5, 2015*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late July.
(C) Dividends historically paid in early Jan., April, July, and October. 1Q '13 div'd paid in 4Q '12. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2014: $377.6 million, $4.48/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	60

NISOURCE INC. NYSE-NI

RECENT PRICE **47.04** | P/E RATIO **25.4** (Trailing: 27.8 / Median: 19.0) | RELATIVE P/E RATIO **1.34** | DIV'D YLD **2.2%** | VALUE LINE

TIMELINESS — Suspended 6/5/15
SAFETY **3** Lowered 1/4/02
TECHNICAL — Suspended 6/5/15
BETA .85 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+5%)	4%
Low	35	(-25%)	-4%

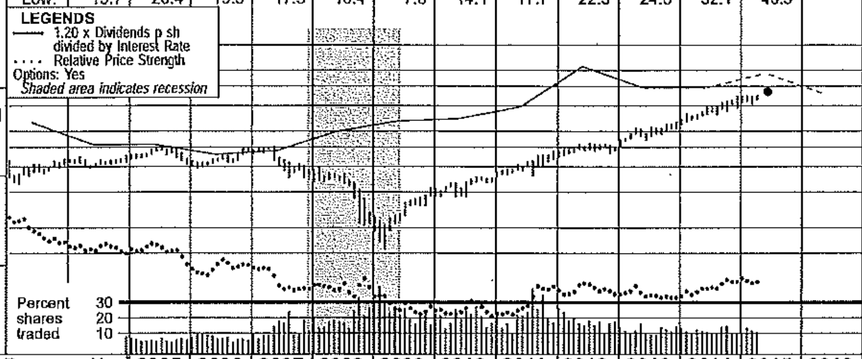
Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	D	0	0	0	0	0	0
Options	0	0	D	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	2	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	172	181	181
to Sell	183	188	198
Hld's(000)	254205	253531	252482

High:	22.8	25.5	24.8	25.4	19.8	15.8	18.0	24.0	26.2	33.5	44.9	47.8
Low:	19.7	20.4	19.5	17.5	10.4	7.6	14.1	17.7	22.3	24.8	32.1	40.9



Target Price Range
2018 | 2019 | 2020

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.5	9.1
3 yr.	90.9	58.8
5 yr.	216.5	84.6

NiSource acquired Columbia Energy on November 1, 2000, paying approximately $6 billion in cash and stock. Columbia shareholders who chose cash received $70 a share, plus a security with a face value of $2.60. Those who chose stock received $74 a share in NiSource common stock. Shareholders' selections were prorated to reflect a 30% stock portion of the transaction. In 2003, NiSource sold Columbia's exploration and production business.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.97	27.37	28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	*21.40*	*22.50*	Revenues per sh	*24.90*
3.14	3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	*4.15*	*4.55*	"Cash Flow" per sh	*5.10*
1.08	1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	*1.85*	*2.05*	Earnings per sh A	*2.60*
.92	.92	.92	.92	.92	.92	.92	.94	.98	1.02	*1.06*	*1.10*	Div'd Decl'd per sh B ■	*1.20*
2.17	2.33	2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	*5.60*	*5.75*	Cap'l Spending per sh	*5.55*
18.09	18.32	18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	*21.35*	*22.50*	Book Value per sh C	*25.55*
272.62	273.65	274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	*320.00*	*320.00*	Common Shs Outst'g D	*325.00*
21.4	19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
1.14	1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.18	*Value*	*Line*	Relative P/E Ratio	*1.00*
4.0%	4.2%	4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*
7899.1	7490.0	7939.8	8874.2	6649.4	6422.0	6019.1	5061.2	5657.3	6470.6	*6850*	*7200*	Revenues ($mill)	*8100*
298.7	314.6	312.0	369.8	231.2	294.6	303.8	410.6	490.9	530.7	*590*	*655*	Net Profit ($mill)	*810*
33.3%	35.2%	35.6%	33.4%	41.8%	32.4%	35.0%	34.4%	34.8%	36.9%	*37.0%*	*37.0%*	Income Tax Rate	*37.5%*
2.1%	4.2%	6.6%	--	--	--	--	--	2.9%	2.9%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
51.2%	50.7%	52.4%	55.7%	55.1%	54.7%	55.6%	55.1%	56.3%	56.9%	*56.0%*	*55.5%*	Long-Term Debt Ratio	*56.0%*
48.0%	49.3%	47.6%	44.3%	44.9%	45.3%	44.4%	44.9%	43.7%	43.1%	*44.0%*	*44.5%*	Common Equity Ratio	*44.0%*
10285	10160	10671	10673	10819	10859	11264	12373	13480	14331	*15475*	*16280*	Total Capital ($mill)	*18810*
9554.3	9694.5	10032	10276	10592	11097	11800	12916	14365	16017	*17300*	*18165*	Net Plant ($mill)	*21025*
4.8%	4.8%	4.6%	5.2%	4.0%	4.5%	4.4%	5.0%	5.2%	5.3%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
6.0%	6.3%	6.1%	7.8%	4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	*8.5%*	*9.0%*	Return on Shr. Equity	*10.0%*
6.0%	6.3%	6.1%	7.8%	4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	*8.5%*	*9.0%*	Return on Com Equity	*10.0%*
.9%	1.2%	1.2%	2.5%	NMF	.8%	.9%	2.5%	3.1%	3.4%	*3.5%*	*4.0%*	Retained to Com Eq	*5.5%*
85%	80%	81%	68%	110%	87%	85%	67%	62%	61%	*57%*	*54%*	All Div'ds to Net Prof	*46%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $8734.6 mill. Due in 5 Yrs $2598.8 mill.
LT Debt $7957.9 mill. LT Interest $450 mill.
(Interest cov. earned: 2.8x) (57% of Cap'l)

Leases, Uncapitalized Annual rentals $22.7 mill.
Pension Assets-12/14 $2.33 bill. Oblig. $2.75 bill.

Pfd Stock None

Common Stock 317,377,794 shs.
as of 4/23/15

MARKET CAP: $14.9 billion (Large Cap)

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	26.8	25.4	42.0
Other	2132.4	2441.1	2219.0
Current Assets	2159.2	2466.5	2261.0
Accts Payable	619.0	670.6	563.9
Debt Due	1240.8	1843.5	776.7
Other	1318.6	1440.8	1417.8
Current Liab.	3178.4	3954.9	2758.4
Fix. Chg. Cov.	267%	274%	283%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-3.0%	-8.5%	5.5%
"Cash Flow"	-.5%	1.5%	7.0%
Earnings	-1.0%	7.0%	9.0%
Dividends	-1.0%	1.5%	3.5%
Book Value	1.0%	1.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1648.9	1039.1	962.9	1410.3	5061.2
2013	1782.2	1201.5	1076.8	1596.8	5657.3
2014	2320.5	1335.1	1123.9	1691.1	6470.6
2015	2149.7	*1450*	*1250*	*2000.3*	*6850*
2016	*2400*	*1450*	*1350*	*2000*	*7200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.66	.23	.06	.42	1.37
2013	.69	.23	.16	.49	1.57
2014	.85	.25	.10	.49	1.67
2015	.85	*.25*	*.15*	*.60*	*1.85*
2016	*.95*	*.30*	*.20*	*.60*	*2.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.23	.23	.23	.23	.92
2012	.23	.23	.24	.24	.94
2013	.24	.24	.25	.25	.98
2014	.25	.25	.26	.26	1.02
2015	.26	.26			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 461,000 electric in Indiana, 3.4 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, Massachusetts through its Columbia subsidiaries. Revenue breakdown, 2014: electrical, 26%; gas, 69%; other, 5%. Generating sources, 2014: coal, 77.3%; purchased & other, 22.7%. 2014 reported depreciation rates: 3.0% electric, 1.8% gas. Has 8,982 employees. Chairman: Ian M. Rolland. President & Chief Executive Officer: Robert C. Skaggs, Jr. Incorporated: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource reported mixed first-quarter results. Revenues fell to $2,149.7 million, but were offset by an increase in gross margins. This allowed the company to match last year's earnings of $0.85 a share. Heading forward, the company will likely benefit from lower interest expenses, but will lose a significant source of revenues due to the pending pipeline spinoff. *Note: The separation is not yet reflected in our presentation.*

NiSource is on track to complete its spinoff of the Columbia Pipeline Group operations by July 1st. The company earlier completed the initial public offering of associated partnership units, and a recapitalization of NiSource is being completed. This will refocus the operations of NiSource, as it will rely on its natural gas distribution and electric operation for long-term growth. This move looks poised to allow for better long-term operations for both companies. *The stock's Timeliness rank is suspended due to the upcoming spinoff.*

Operations will widely differ after the split. Indeed, much of the sizable year-on-year growth has been driven by strong results in the pipelines business. In the years ahead, NiSource will drive earnings growth through infrastructure replacement in its electrical and natural gas operations, including around $1.3 billion in 2015. Too, the dividend payouts will be split between the two companies with NiSource expected to pay $0.62 a share a year. *(Columbia will pay $0.50 a share.)*

The balance sheet will be in flux until the spinoff is completed. Indeed, around $1.2 billion in equity was raised during the IPO of Columbia, while Columbia Pipeline has raised $2.75 billion in debt to pay back NiSource through both a one-time dividend and debt repayment. This should help to delever NiSource, allowing for lower interest costs.

Shares of NiSource are not attractive at present. This issue is trading near the high end of our long-term price projections, and will likely start trading based on its utility operations headed forward. Too, this issue has a much lower payout than other natural gas utilities. All told, most long-term investors can look elsewhere, at this juncture.

John E. Seibert III *June 5, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (4¢); gains (losses) on disc. ops.: '05, 10¢; '06, (11¢); '07, 3¢; '08, ($1.14). Next egs. report due late July. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '14: $3930.9 million, $12.45/sh.
(D) In mill.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	75

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 44.45 | P/E RATIO 23.4 (Trailing: 20.9 Median: 18.0) | RELATIVE P/E RATIO 1.23 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 5/15/15
SAFETY 1 Raised 3/18/05
TECHNICAL 4 Lowered 5/15/15
BETA .70 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	34.1	39.6	43.7	52.8	55.2	46.5	50.9	49.0	50.8	46.6	52.6	52.3
Low:	27.5	32.4	32.8	39.8	37.7	37.7	41.1	39.6	41.0	40.0	40.1	43.8

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

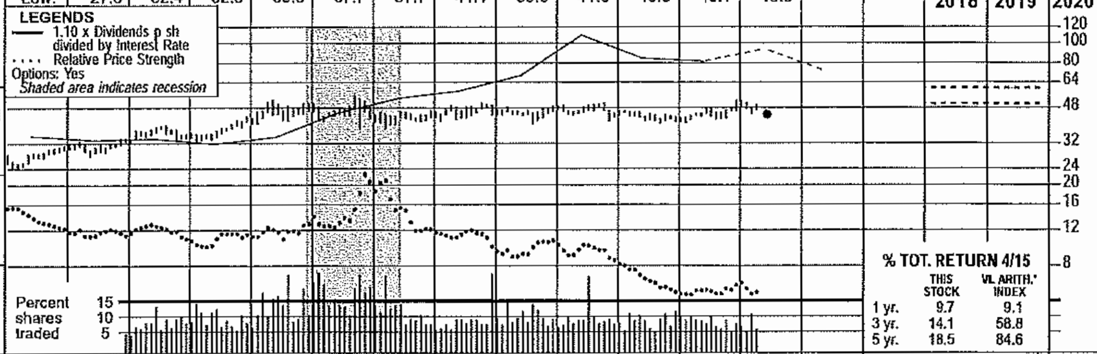
	Price	Gain	Ann'l Total Return
High	60	(+35%)	11%
Low	50	(+10%)	7%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	1	0	0	3
to Sell	0	0	0	0	1	2	2	0	4

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	84	79	79
to Sell	53	65	66
Hld's(000)	16493	16110	16761



% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.7	9.1
3 yr.	14.1	58.8
5 yr.	18.5	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	28.35	29.55	Revenues per sh	31.25
3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.75	5.25	"Cash Flow" per sh	6.45
1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.90	2.30	Earnings per sh A	3.30
1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.87	1.91	Div'ds Decl'd per sh B■	2.10
4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	5.80	6.15	Cap'l Spending per sh	6.80
17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.85	29.95	Book Value per sh D	33.85
25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.50	27.75	Common Shs Outst'g C	28.00
14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	*Bold figures are*		Avg Ann'l P/E Ratio	17.0
.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	*Value Line*		Relative P/E Ratio	1.05
5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	*estimates*		Avg Ann'l Div'd Yield	3.3%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $827.9 mill. Due in 5 Yrs $360.0 mill.
LT Debt $621.7 mill. LT Interest $45.0 mill.

(Total interest coverage: 2.5x)

Pension Assets-12/14 $279.2 mill. Oblig. $487.3 mill.

Pfd Stock None

Common Stock 27,332,671 shares as of 4/24/15

MARKET CAP $1.2 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	730.6	758.5	754.0	780	820	Revenues ($mill)	875
58.1	65.2	74.5	68.5	75.1	72.7	63.9	59.9	60.5	58.7	78.0	82.0	Net Profit ($mill)	92.5
36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	42.4%	40.8%	41.5%	40.0%	40.0%	Income Tax Rate	38.0%
6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	8.2%	8.0%	7.8%	6.7%	7.8%	Net Profit Margin	10.6%
47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	48.5%	47.6%	44.8%	44.5%	44.5%	Long-Term Debt Ratio	44.0%
53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	51.5%	52.4%	55.2%	55.5%	55.5%	Common Equity Ratio	56.0%
1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	1424.7	1433.6	1389.0	1435	1495	Total Capital ($mill)	1685
1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	1973.6	2062.9	2121.6	2205	2295	Net Plant ($mill)	2580
6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	5.7%	5.8%	5.8%	5.0%	5.5%	Return on Total Cap'l	6.5%
9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.5%	7.5%	Return on Shr. Equity	10.0%
9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.5%	7.5%	Return on Com Equity	10.0%
3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	1.6%	1.5%	1.1%	Nil	1.5%	Retained to Com Eq	3.5%
63%	59%	52%	59%	56%	61%	73%	80%	81%	85%	98%	83%	All Div'ds to Net Prof	64%

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	9.5	9.5	5.2
Other	321.0	353.1	286.8
Current Assets	330.5	362.6	292.0
Accts Payable	96.1	91.4	62.9
Debt Due	248.2	274.7	206.2
Other	88.5	103.3	101.6
Current Liab.	432.8	469.4	370.7
Fix. Chg. Cov.	316%	321%	251%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	-6.5%	2.0%
"Cash Flow"	3.0%	-1.0%	4.5%
Earnings	2.5%	-4.0%	7.0%
Dividends	3.5%	3.5%	2.5%
Book Value	3.5%	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	309.6	104.0	87.5	229.5	730.6
2013	277.9	131.7	88.2	260.7	758.5
2014	293.4	133.1	87.2	240.3	754.0
2015	261.7	148.3	100	270	780
2016	280	150	105	285	820

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1.51	.05	d.39	1.05	2.22
2013	1.40	.08	d.31	1.07	2.24
2014	1.40	.04	d.32	1.04	2.16
2015	1.04	.10	d.30	1.06	1.90
2016	1.40	.10	d.30	1.10	2.30

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.435	.435	.435	.445	1.75
2012	.445	.445	.445	.455	1.79
2013	.455	.455	.455	.460	1.83
2014	.460	.460	.460	.465	1.85
2015	.465	.465			

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 704,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugane, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 35%; commercial, 22%; industrial, gas transportation, and other, 43%. Employs 1,092. BlackRock Inc. owns 9.2% of shares; officers and directors, 2.1% (4/15 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Warmer-than-usual winter weather caused underwhelming results at Northwest Natural Gas. Too, the company had a negative outcome from Oregon regulators, which caused a pretax charge of $15 million for disallowed environmental remediation expense recoveries. These together caused earnings to fall to $1.04 a share. Though we think the rest of the year will show improvement, we are lowering our 2015 per-share estimate by $0.50, to $1.90.

Northwest Natural Gas continues to show signs of growth. The customer growth rate in the Portland area was 1.3%, and employment there continues to improve. We think 2016 should show a sizable jump in earnings, assuming improvements come from more normal weather and increased returns from capital investments. We think that 2015 is the last year of declining earnings and that $2.30 a share is likely in 2016.

The Mist plant expansion appears to be headed forward. Indeed, it received approval from Portland General Electric and will provide storage to the natural gas-fired plants in Port Westward. This will provide up to 2.5 billion cubic feet of storage and will likely cost around $125 million, with a potential in-service date in the 2018-2019 winter season. This long-term project should allow for ample growth once completed. We are assuming it comes in on time. Construction and permitting can take longer than expected at times, though the Mist underground storage facility and related pipelines should increase revenues.

The dividend is a top draw. The slide in the share price has allowed the yield to top 4.2%, which is above average for a natural gas utility. Given the payout ratio remains high when compared to historical levels, we expect dividend expansion will be somewhat muted over the coming years.

This issue does not stand out for Timeliness (3). Shares of Northwest Natural Gas have recently declined 10% in price, hurt by a lackluster earnings report. Also, this issue sports a decent yield and 3- to 5-year total return potential, and carries our Highest mark for Safety. This issue should appeal to conservative income-seekers, at this juncture.

John E. Seibert III *June 5, 2015*

(A) Diluted earnings per share. Excludes nonrecurring items: '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢; May not sum due to rounding. Next earnings report due in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2014: $368.9 million, $13.52/share.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	100

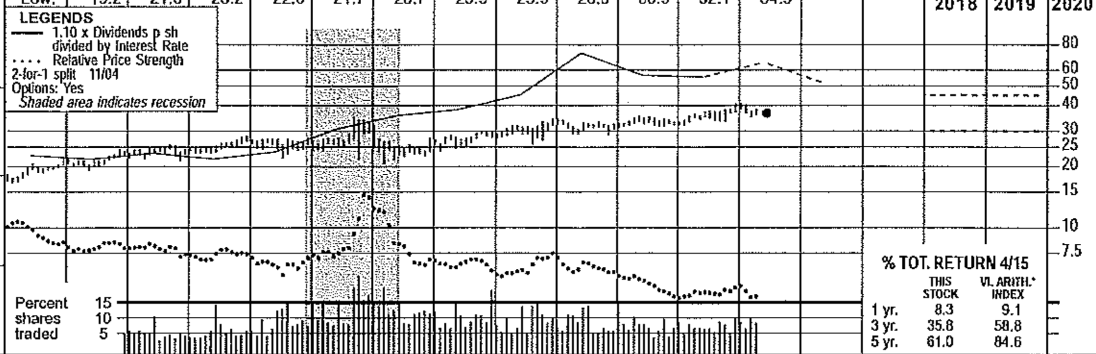
PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 36.78 | P/E RATIO 19.5 (Trailing: 20.9; Median: 19.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 4 Lowered 12/5/14
SAFETY 2 New 7/27/90
TECHNICAL 4 Lowered 6/5/15
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6	35.5	41.0	41.1
Low:	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.5	30.9	32.1	34.9

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	30	(-20%)	-1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	1	0	1

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	99	107	111
to Sell	72	82	94
Hld's(000)	39611	40379	41698

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.3	9.1
3 yr.	35.8	58.8
5 yr.	61.0	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	19.83	15.54	17.07	18.87	*19.25*	*19.55*	Revenues per sh A	*21.10*
1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	2.99	3.09	3.29	3.37	*3.45*	*3.55*	"Cash Flow" per sh	*3.65*
.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	1.66	1.78	1.84	*1.85*	*2.00*	Earnings per sh AB	*2.10*
.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	1.19	1.23	1.27	*1.31*	*1.35*	Div'ds Decl'd per sh C■	*1.47*
1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	1.76	2.75	3.37	7.33	8.01	5.91	*6.10*	*6.00*	Cap'l Spending per sh	*5.95*
7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	14.21	15.87	16.80	*17.40*	*18.35*	Book Value per sh D	*20.40*
62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.27	72.28	72.32	72.25	74.88	77.88	*78.00*	*79.00*	Common Shs Outst'g E	*80.00*
17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	15.4	17.1	18.9	19.2	18.5	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	1.22	1.04	1.04	*Value Line*		Relative P/E Ratio	*1.13*
4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	3.9%	3.7%	3.7%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*
						1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	1122.8	1278.2	1469.9	*1500*	*1545*	Revenues ($mill) A	*1690*
						101.3	97.2	104.4	110.0	122.8	111.8	113.6	119.8	134.4	143.8	*145*	*160*	Net Profit ($mill)	*170*
						33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	29.7%	32.6%	25.0%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
						5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	10.7%	10.5%	9.8%	*10.0%*	*10.0%*	Net Profit Margin	*10.0%*
						41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	48.7%	49.7%	52.1%	*48.0%*	*46.0%*	Long-Term Debt Ratio	*43.0%*
						58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	51.3%	50.3%	47.9%	*52.0%*	*54.0%*	Common Equity Ratio	*56.5%*
						1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	2002.0	2363.5	2733.0	*2610*	*2700*	Total Capital ($mill)	*2885*
						1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	3105.1	3634.5	3989.4	*4050*	*4100*	Net Plant ($mill)	*4250*
						8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	7.0%	6.8%	6.4%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
						11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.7%	11.3%	11.0%	*11.0%*	*11.0%*	Return on Shr. Equity	*10.5%*
						11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.7%	11.3%	11.0%	*11.0%*	*11.0%*	Return on Com Equity	*10.5%*
						3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	3.3%	3.6%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
						68%	74%	70%	69%	64%	72%	73%	72%	69%	69%	*69%*	*68%*	All Div'ds to Net Prof	*69%*

CAPITAL STRUCTURE as of 1/31/15
Total Debt $1904.4 mill. Due in 5 Yrs $175.0 mill.
LT Debt $1424.4 mill. LT Interest $61.6 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/14 $364.2 mill. Oblig. $346.4 mill.

Pfd Stock None

Common Stock 78,778,900 shs. as of 2/27/15
MARKET CAP: $2.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2013	2014	1/31/15
Cash Assets	8.1	9.6	19.9
Other	340.0	338.4	475.6
Current Assets	348.1	348.0	495.5
Accts Payable	140.1	139.7	159.8
Debt Due	500.0	355.0	480.0
Other	76.6	127.3	143.1
Current Liab.	716.7	622.0	782.9
Fix. Chg. Cov.	325%	325%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	-7.5%	*3.5%*
"Cash Flow"	5.0%	3.5%	*2.0%*
Earnings	5.0%	3.5%	*3.0%*
Dividends	4.0%	3.5%	*3.0%*
Book Value	5.0%	4.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2012	471.8	308.4	161.2	181.4	1122.8
2013	515.9	399.4	162.9	200.0	1278.2
2014	657.7	462.2	164.2	185.8	1469.9
2015	607.3	*455*	*210*	*227.7*	*1500*
2016	*620*	*465*	*225*	*235*	*1545*

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2012	1.05	.70	d.06	d.03	1.66
2013	1.18	.74	d.03	d.11	1.78
2014	1.26	.80	d.09	d.13	1.84
2015	1.18	*.82*	*d.05*	*d.10*	*1.85*
2016	*1.22*	*.86*	*d.02*	*d.06*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.28	.29	.29	.29	1.15
2012	.29	.30	.30	.60	1.49
2013	--	.31	.31	.31	.93
2014	.31	.32	.32	.32	1.27
2015	.32	.33			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 992,551 customers in North Carolina, South Carolina, and Tennessee. 2014 revenue mix: residential (46%), commercial (27%), industrial (14%), other (13%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 51.4% of revenues. '14 deprec. rate: 2.7%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,879 employees. Off./dir. own about 1.1% of common stock, BlackRock; 8.6% (1/15 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas posted mixed financial results for the January quarter. Indeed, the company's revenues declined 7.7%, to $607.3 million. This was modestly higher than our earlier call, thanks to the benefits of the higher rates in North Carolina and Tennessee, new customer additions of approximately 4,900, and a rise in overall system throughput of 2.7%. On the downside, the year-over-year decline in natural gas pricing was a key detractor to the top line. On the profitability front, cost of goods sold decreased 470 basis points as a percentage of revenues. This benefit was partially offset by a 290-basis-point rise in operating expenses. After accounting for lower income from equity investments, higher interest costs, and a steadily rising share count, first-quarter earnings fell 6.3%, to $1.18 a share. This was lower than our earlier expectation.

Consequently, we have shaved a nickel off our 2015 bottom-line estimate, to $1.85 a share. This would represent a relatively unchanged earnings figure when compared to fiscal 2014 and falls in line with management's recently reiterated guidance range of $1.82-$1.92 per share. We continue to look for a low single-digit revenue increase this year, thanks to new customer accounts and rising system throughput. Alternatively, the company did file for rate reductions in North and South Carolina in an effort to pass through price reductions on wholesale natural gas to its end-use customers.

The balance sheet is in decent shape and improving. Indeed, PNY's cash reserves doubled during the first quarter of 2015, to almost $20 million. At the same time, the long-term debt load has remained constant. Although it does represent a somewhat high 50% of total capital, this figure is acceptable for a utility company, and has not proven to be problematic in the past. Finally, the board recently approved a 3% hike in the quarterly dividend, to $0.33 a share. Despite that increase, the stock's yield is below average when compared to the rest of the industry.

At this juncture, these untimely shares do not stand out. The stock's total return potential is subpar.

Bryan J. Fong   *June 5, 2015*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '10, 41¢. Next earnings report dua mid-July.
Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid aarly-January, April, July, October. 2013 Q1 dividend paid in Q4 of 2012. ■ Div'd reinvest. plan available; 5% discount. (D) Includes deferred charges. In 2014: $809.5 million, $10.30/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	95

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 26.31 | P/E RATIO 15.9 (Trailing: 18.5 Median: 17.0) | RELATIVE P/E RATIO 0.84 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 4/10/15
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Lowered 5/1/15
BETA .85 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	13.3	16.2	17.1	20.6	20.3	20.4	27.1	29.0	29.0	31.1	30.6
Low:	9.8	12.5	12.8	15.6	12.6	16.0	18.6	21.4	22.9	25.3	25.9

High:	30.4
Low:	25.4

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+50%)	15%
Low	30	(+15%)	8%

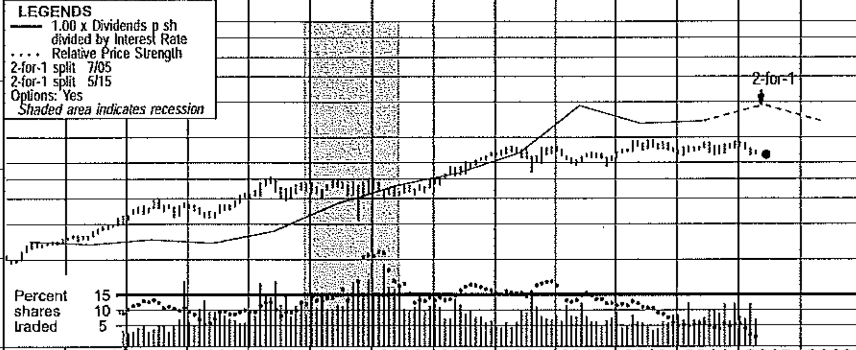
Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	2	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	1	1	0	0	0	0	0	0	1

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	78	90	97
to Sell	73	67	60
Hld's(000)	41346	41708	42328

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
2-for-1 split 5/15
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020
120 100 80 64 48 32 24 20 16 12 8

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.0	9.1
3 yr.	18.3	58.8
5 yr.	36.8	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
8.80	11.22	17.65	10.35	13.17	14.75	15.89	15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	*13.85*	*14.95*	Revenues per sh	*18.40*
.92	.97	.95	1.06	1.12	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	*2.70*	*2.90*	"Cash Flow" per sh	*4.00*
.50	.54	.57	.61	.68	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	*1.65*	*1.80*	Earnings per sh A	*2.50*
.36	.37	.37	.38	.39	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	*1.02*	*1.10*	Div'ds Decl'd per sh B ■	*1.35*
1.09	1.11	1.41	1.74	1.18	1.34	1.60	1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	*3.55*	*3.80*	Cap'l Spending per sh	*4.60*
3.37	3.62	3.91	4.84	5.63	6.20	6.75	7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	*15.00*	*15.95*	Book Value per sh C	*18.40*
44.61	46.00	47.44	48.83	52.92	55.52	57.96	58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	*70.00*	*72.00*	Common Shs Outst'g D	*76.00*
13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	*Value Line*		Relative P/E Ratio	*.90*
5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 3/31/15
Total Debt $1281.8 mill. Due in 5 Yrs $838.9 mill.
LT Debt $859.5 mill. LT Interest $23.0 mill.
(Total interest coverage: 4.9x)

Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $180.5 mill. Oblig. $265.4 mill.

Pfd Stock None

Common Stock 68,456,764 shs. as of 5/1/15, adj. for 2-for-1 split

MARKET CAP: $1.8 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
921.0	931.4	956.4	962.0	845.4	925.1	828.6	706.3	731.4	887.0	*970*	*1075*	Revenues ($mill)	*1400*
48.6	72.0	61.8	67.7	71.3	81.0	87.0	93.3	97.1	104.0	*120*	*135*	Net Profit ($mill)	*195*
41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	10.8%	10.8%	20.0%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	13.2%	13.3%	11.7%	*12.4%*	*12.6%*	Net Profit Margin	*13.9%*
44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	45.0%	45.1%	48.0%	*47.0%*	*46.5%*	Long-Term Debt Ratio	*47.0%*
55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	55.0%	54.9%	52.0%	*53.0%*	*53.5%*	Common Equity Ratio	*53.0%*
710.3	801.1	839.0	848.0	856.4	910.1	1048.3	1337.6	1507.4	1791.9	*1975*	*2150*	Total Capital ($mill)	*2650*
877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	1578.0	1859.1	2134.1	*2250*	*2350*	Net Plant ($mill)	*2750*
8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	7.4%	6.8%	6.4%	*6.5%*	*7.0%*	Return on Total Cap'l	*8.0%*
12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	*11.5%*	*11.5%*	Return on Shr. Equity	*14.0%*
12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	*11.5%*	*11.5%*	Return on Com Equity	*14.0%*
6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	5.8%	4.8%	4.3%	*4.5%*	*5.0%*	Retained to Com Eq	*6.5%*
50%	37%	48%	49%	51%	50%	52%	55%	59%	61%	*60%*	*59%*	All Div'ds to Net Prof	*53%*

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	3.8	4.2	7.2
Other	479.1	562.5	573.0
Current Assets	482.9	566.7	580.2
Accts Payable	259.8	273.0	221.2
Debt Due	374.9	395.6	422.3
Other	130.3	181.6	178.1
Current Liab.	765.0	850.2	821.6
Fix. Chg. Cov.	370%	432%	455%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.0%	-5.5%	*7.5%*
"Cash Flow"	8.0%	7.5%	*8.0%*
Earnings	8.0%	6.5%	*8.5%*
Dividends	8.5%	10.0%	*7.0%*
Book Value	8.5%	8.0%	*6.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	274.8	121.9	112.0	197.6	706.3
2013	255.6	122.6	128.8	224.4	731.4
2014	350.2	133.3	122.4	281.1	887.0
2015	383.0	*155*	*145*	*287*	*970*
2016	*415*	*175*	*165*	*320*	*1075*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.83	.14	.07	.49	1.52
2013	.76	.16	d.02	.62	1.52
2014	1.01	.15	d.05	.47	1.57
2015	.86	*.16*	*.03*	*.60*	*1.65*
2016	*.93*	*.18*	*.04*	*.65*	*1.80*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	--	.183	.183	.384	.75
2012	--	.202	.202	.423	.83
2013	--	.222	.222	.458	.90
2014	--	.237	.237	.488	.96
2015	--	.251			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 366,854 customers in New Jersey's southern counties. Gas revenue mix '14: residential, 43%; commercial, 19%; cogeneration and electric generation, 17%; industrial, 21%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 700 employees. Off./dir. own .8% of common shares; BlackRock, Inc., 9.5%; The Vanguard Group, Inc., 6.9% (3/15 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries completed a 2-for-1 stock split in early May. As a result, the number of shares outstanding rose to just under 69 million. The company cited healthy operating performance and favorable growth prospects as factors supporting the decision to effect the split. Our per-share figures have been adjusted accordingly.

The company reported mixed results for the March quarter. The top line advanced roughly 9%, on a year-over-year basis. This was the result of impressive growth at the utility operation, which more than offset lower revenues from the nonutility side. Operating expenses also increased, however, and earnings per share of $0.86 were no match for the prior-year tally.

We expect favorable comparisons in the coming quarters, and higher revenues and share earnings for full-year 2015. The utility ought to be an important performance driver going forward. South Jersey Gas should continue to experience healthy customer growth, as natural gas remains the fuel of choice within its service territory. This business will likely continue to gain from customer conversions to natural gas, given its cost effectiveness compared to alternatives. On the nonutility side, the company's wholesale and retail commodity businesses should also post solid results, driven by demand for fuel management services from four large gas-fired merchant generating facilities, and SJI's portfolio of transportation assets. The energy services business ought to benefit from the healthy performance of its energy production portfolio, too.

This stock is neutrally ranked for year-ahead relative price performance. Looking further out, we expect healthy growth in revenues and share earnings for the company from 2016 onward. On top of that, South Jersey Industries earns high marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. All things considered, this good-quality stock offers solid risk-adjusted total return potential for the pull to late decade. Conservative, income-oriented investors may find something to like here. Dividend growth looks to be a strong point here.

Michael Napoli, CFA *June 5, 2015*

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $1.05; '08, $1.29; '09, $0.97; '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46. Excl. non-recur. gain (loss): '01, $0.07; '08, $0.16; '09, ($0.22); '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11). Earnings may not sum due to rounding. Next egs. report due in August. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2014: $357.2 mill., $5.23 per shr. (D) In mill., adj. for split.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	95

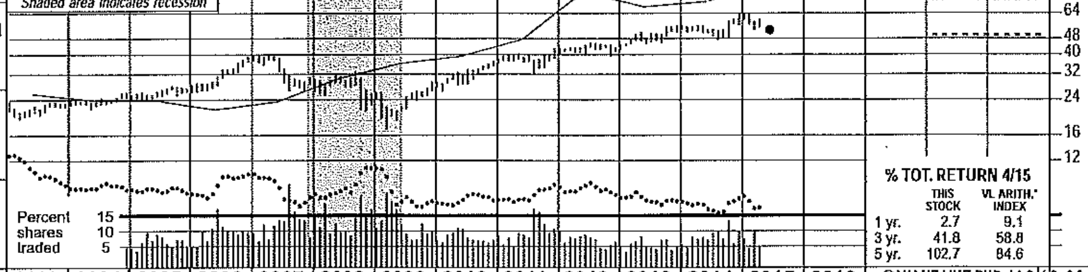
SOUTHWEST GAS NYSE-SWX

RECENT PRICE 53.01 | P/E RATIO 16.8 (Trailing: 17.5 Median: 16.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 2 Raised 3/27/15
SAFETY 3 Lowered 1/4/91
TECHNICAL 5 Lowered 6/5/15
BETA .85 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	26.2	28.1	39.4	39.9	33.3	29.5	37.3	43.2	46.1	56.0	64.2	63.7
Low:	21.5	23.5	26.0	26.5	21.1	17.1	26.3	32.1	39.0	42.0	47.2	51.7

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+40%)	12%
Low	50	(-5%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	3
to Sell	0	0	2	0	2	3	0	0	5

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	92	83	83
to Sell	91	97	87
Hld's(000)	36272	36458	35979

Percent shares traded 15 10 5

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.7	9.1
3 yr.	41.8	58.8
5 yr.	102.7	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	47.90	49.80	Revenues per sh	53.85
4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.95	9.40	"Cash Flow" per sh	11.05
1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	3.15	3.40	Earnings per sh A	4.25
.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.74	Div'ds Decl'd per sh B■†	2.10
7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	8.75	9.40	Cap'l Spending per sh	11.55
16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	34.40	35.70	Book Value per sh	39.40
30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	48.00	49.00	Common Shs Outst'g C	52.00
21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	Bold figures are	Value Line	Avg Ann'l P/E Ratio	15.0
1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89	.98	.95	.89	.94	estimates		Relative P/E Ratio	.95
3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%			Avg Ann'l Div'd Yield	3.3%
						1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	1887.2	1927.8	1950.8	2121.7	2300	2440	Revenues ($mill)	2800
						48.1	80.5	83.2	61.0	87.5	103.9	112.3	133.3	145.3	141.1	155	170	Net Profit ($mill)	225
						29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	36.2%	36.2%	35.0%	35.7%	35.0%	35.0%	Income Tax Rate	35.0%
						2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	6.0%	6.9%	7.4%	6.7%	6.7%	7.0%	Net Profit Margin	8.0%
						63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	43.2%	49.2%	49.4%	52.4%	49.0%	49.0%	Long-Term Debt Ratio	47.5%
						36.2%	39.4%	41.9%	44.7%	46.5%	50.9%	56.8%	50.8%	50.6%	47.6%	51.0%	51.0%	Common Equity Ratio	52.5%
						2076.0	2287.8	2349.7	2323.3	2371.4	2291.7	2155.9	2576.9	2793.7	3123.9	3250	3425	Total Capital ($mill)	3900
						2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	3218.9	3343.8	3486.1	3658.4	3800	4000	Net Plant ($mill)	4500
						4.3%	5.5%	5.5%	4.5%	5.4%	6.1%	6.4%	6.4%	6.3%	5.7%	6.0%	6.0%	Return on Total Cap'l	7.0%
						6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	9.5%	9.5%	Return on Shr. Equity	11.0%
						6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	9.5%	9.5%	Return on Com Equity	11.0%
						2.2%	5.2%	4.8%	2.1%	4.1%	5.1%	5.3%	6.1%	6.1%	5.0%	4.5%	5.0%	Retained to Com Eq	5.5%
						65%	42%	44%	63%	48%	43%	43%	40%	41%	47%	50%	50%	All Div'ds to Net Prof	49%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $1524.8 mill. Due in 5 Yrs $405.0 mill.
LT Debt $1506.5 mill. LT Interest $72.0 mill.
(Total interest coverage: 4.1x) (49% of Cap'l)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/14 $799.7 mill.
Oblig. $1132.4 mill.

Pfd Stock None

Common Stock 46,842,753 shs.
as of 4/28/15

MARKET CAP: $2.5 billion (Mid Cap)

CURRENT POSITION ($MLL.)	2013	2014	3/31/15
Cash Assets	41.1	39.6	38.0
Other	453.6	567.2	489.2
Current Assets	494.7	606.8	527.2
Accts Payable	183.5	168.0	119.4
Debt Due	11.1	24.2	18.3
Other	239.6	277.9	339.9
Current Liab.	434.2	470.1	477.6
Fix. Chg. Cov.	430%	395%	396%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	1.0%	-1.5%	4.0%
"Cash Flow"	4.5%	6.0%	5.0%
Earnings	8.5%	11.0%	6.0%
Dividends	5.0%	8.0%	8.0%
Book Value	5.0%	5.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	657.6	409.8	371.8	488.6	1927.8
2013	613.5	411.6	387.3	538.4	1950.8
2014	608.4	453.2	432.5	627.7	2121.7
2015	734.2	480	450	635.8	2300
2016	755	520	485	680	2440

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1.70	d.08	d.09	1.33	2.86
2013	1.73	.22	d.06	1.22	3.11
2014	1.51	.21	.04	1.25	3.01
2015	1.53	.23	.05	1.34	3.15
2016	1.62	.28	.07	1.43	3.40

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.250	.265	.265	.265	1.05
2012	.265	.295	.295	.295	1.15
2013	.295	.330	.330	.330	1.29
2014	.330	.365	.365	.365	1.43
2015	.365	.405			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.9 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2014 margin mix: residential and small commercial, 85%; large commercial and industrial, 4%; transportation, 11%. Total throughput: 1.9 billion therms. Has 6,232 employees. Off. & Dir. own 1.5% of common stock; BlackRock Inc., 9.6%; The Vanguard Group, Inc., 6.9%; GAMCO Investors, Inc., 6.8%; T. Rowe Price Assoc., Inc., 6.5% (3/15 Proxy). Chairman: Michael J. Melarkey. CEO: John Hester. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Tel.: 702-876-7237. Web: www.swgas.com.

Shares of Southwest Gas have traded lower in recent months, after reaching an all-time high late last year. The company reported a significant top-line advance for the March quarter, though share earnings of $1.53 increased only slightly from the prior-year tally. The utility business benefited from modest customer growth and rate relief in California. Operating expenses declined here, as well. However, the construction services business posted a deficit for the period, owing to seasonal factors and the establishment of a loss reserve for a short-duration industrial project in Canada. Nevertheless, incremental revenue from pending orders under negotiation is expected to narrow or reverse the loss reserve here in subsequent periods.

We anticipate solid performance in the coming quarters. The company's utility operation will probably continue to experience modest growth in its customer base. Rate relief should also support results. A focus on this matter will remain important, as the utility depends on such approved revenue increases to provide compensation for higher operating expenses and investment in infrastructure. Elsewhere, we expect improvement from the construction services line. This operation ought to benefit from healthy demand, considering the need to replace aging infrastructure. Several acquisitions completed by this business in the second half of last year have expanded its customer base, geographic scope, and technical service offerings. Moreover, efforts to control operating costs should support profitability. All told, we expect greater revenues and share earnings for the company for full-year 2015. Improvement ought to continue the following year.

This stock is ranked to outperform the broader market averages for the coming six to 12 months. On top of that, this issue earns favorable marks for Price Stability, Earnings Predictability, and Price Growth Persistence. Moreover, we envision healthy growth for the company over the pull to late decade. However, this appears to be partly reflected in the recent quotation, and the equity's total return potential is nothing to write home about at this juncture.

Michael Napoli, CFA *June 5, 2015*

(A) Diluted earnings. Excl. nonrec. gains (losses): '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due early August. (B) Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions. (D) Totals may not sum due to rounding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	80

UGI CORP. NYSE-UGI

RECENT PRICE 36.56 | P/E RATIO 18.4 (Trailing: 19.4 Median: 14.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 2 Raised 3/27/15
SAFETY 2 Raised 9/17/04
TECHNICAL 4 Lowered 5/22/15
BETA .95 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	13.8	20.0	19.3	19.8	19.2	18.3	21.7	22.4	22.4	28.8	39.7	38.6
Low:	10.0	12.8	13.5	15.2	12.5	14.1	15.9	16.0	17.3	21.9	26.8	31.5

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

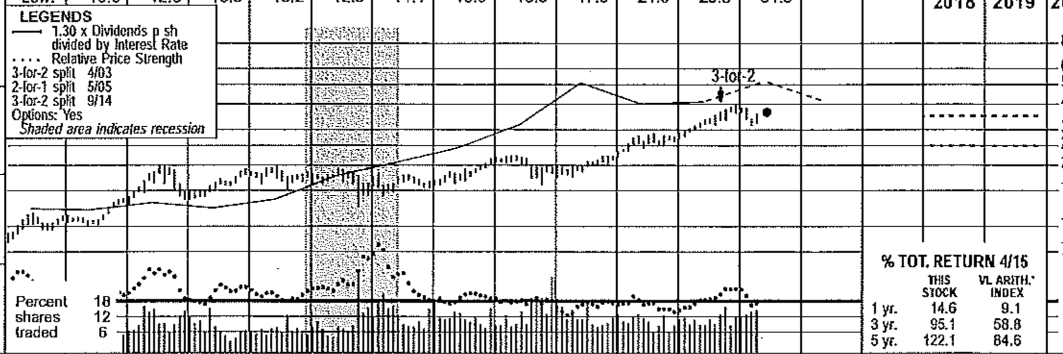
	Price	Gain	Ann'l Total Return
High	35	(-5%)	1%
Low	25	(-30%)	-6%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	1	0	0	0
Options	0	5	0	0	0	3	1	1	0
to Sell	0	6	2	0	0	3	0	1	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	150	154	181
to Sell	135	156	152
Hld's(000)	136174	134645	133925



% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.6	9.1
3 yr.	95.1	58.8
5 yr.	122.1	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
11.27	14.50	20.09	17.76	23.62	24.63	31.10	33.01	34.24	41.27	35.25	34.01	36.31	38.56	42.10	47.92	41.55	45.60	Revenues per sh A	51.30
1.08	1.16	1.32	1.36	1.59	1.63	2.09	2.05	2.26	2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.15	4.30	"Cash Flow" per sh	4.95
.30	.35	.47	.60	.76	.81	1.15	1.10	1.18	1.33	1.57	1.59	1.37	1.17	1.59	1.92	1.95	2.10	Earnings per sh AB	2.65
.33	.34	.35	.36	.38	.40	.43	.46	.48	.50	.52	.60	.68	.71	.74	.79	.88	.92	Div'ds Decl'd per sh C ■	1.01
.57	.58	.64	.76	.79	.87	1.01	1.21	1.39	1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.80	2.90	Cap'l Spending per sh	3.05
2.03	2.04	2.08	2.55	4.45	5.43	6.35	6.95	8.26	8.80	9.78	11.10	11.79	13.21	14.59	15.39	16.90	18.40	Book Value per sh D	23.25
122.72	121.47	122.83	124.66	128.10	153.63	157.20	158.18	159.97	161.09	162.78	164.38	167.75	169.06	170.88	172.73	177.00	180.00	Common Shs Outst'g E	180.00
15.9	13.6	12.1	11.4	12.6	13.4	13.8	14.0	15.1	13.3	10.3	10.9	15.0	16.4	15.4	15.8	Bold figures are		Avg Ann'l P/E Ratio	12.0
.91	.88	.62	.62	.72	.71	.73	.76	.80	.80	.69	.69	.94	1.04	.87	.83	Value Line		Relative P/E Ratio	.75
6.9%	7.0%	6.2%	5.3%	3.9%	3.7%	2.7%	3.0%	2.7%	2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	estimates		Avg Ann'l Div'd Yield	3.1%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $3518.6 mill. Due in 5 Yrs $1379 mill.
LT Debt $2958.2 mill. LT Interest $237 mill.
(Total interest coverage: 4.2x)

Leases, Uncapitalized Annual rentals $72.6 mill.
Pension Assets-9/14 $472 mill. Oblig. $595 mill.

Pfd Stock None

Common Stock 172,497,596 shares as of 4/30/15

MARKET CAP: $6.3 bill. (Mid. Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
4888.7	5221.0	5476.9	6648.2	5737.8	5591.4	6091.3	6519.2	7194.7	8277.3	7350	8200	Revenues ($mill) A	9230
182.0	176.2	191.8	215.5	258.5	261.0	232.9	199.4	278.1	337.2	345	380	Net Profit ($mill)	480
39.5%	30.5%	23.8%	30.6%	29.4%	32.0%	29.8%	34.8%	27.6%	30.6%	30.0%	30.0%	Income Tax Rate	30.0%
3.7%	3.4%	3.5%	3.2%	4.5%	4.7%	3.8%	3.1%	3.9%	4.1%	4.3%	4.6%	Net Profit Margin	5.2%
58.3%	64.1%	60.7%	58.4%	56.2%	44.0%	51.6%	60.0%	58.7%	56.4%	54.0%	52.0%	Long-Term Debt Ratio	46.0%
41.7%	35.9%	39.3%	41.6%	43.8%	56.0%	48.4%	40.0%	41.3%	43.6%	46.0%	48.0%	Common Equity Ratio	54.0%
2390.1	3064.6	3360.7	3405.0	3630.0	3256.7	4088.0	5580.7	6034.7	6092.7	6485	6860	Total Capital ($mill)	7735
1802.7	2214.7	2397.4	2449.5	2903.6	3053.2	3204.5	4233.1	4480.2	4543.7	4610	4675	Net Plant ($mill)	4875
9.8%	7.5%	7.4%	7.9%	8.9%	10.1%	7.4%	5.6%	6.6%	7.5%	5.5%	5.5%	Return on Total Cap'l	6.0%
18.2%	16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	11.5%	11.5%	Return on Shr. Equity	11.5%
18.2%	16.0%	14.5%	15.2%	16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	11.5%	11.5%	Return on Com Equity	11.5%
11.5%	9.4%	8.7%	9.5%	10.9%	8.9%	6.0%	3.6%	6.1%	7.6%	6.5%	6.5%	Retained to Com Eq	7.5%
37%	41%	40%	38%	33%	38%	49%	60%	45%	40%	45%	42%	All Div'ds to Net Prof	34%

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	389.3	419.5	445.5
Other	1238.0	1243.5	1513.5
Current Assets	1627.3	1663.0	1959.0
Accts Payable	472.3	459.8	440.8
Debt Due	295.1	288.0	560.4
Other	657.5	683.1	848.5
Current Liab.	1424.9	1430.9	1849.7
Fix. Chg. Cov.	338%	338%	340%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	7.0%	3.0%	3.0%
"Cash Flow"	9.0%	7.5%	5.5%
Earnings	8.0%	3.0%	9.0%
Dividends	7.0%	8.0%	5.0%
Book Value	13.5%	10.0%	8.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	1690	2427	1277	1125	6519.2
2013	2018	2542	1374	1259	7194.7
2014	2316	3163	1486	1311	8277.3
2015	2005	2456	1510	1379	7350
2016	2055	3175	1560	1410	8200

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	.51	.79	d.04	d.09	1.17
2013	.60	.99	.09	d.09	1.59
2014	.70	1.23	.10	d.11	1.92
2015	.66	1.23	.15	d.09	1.95
2016	.70	1.29	.17	d.06	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.17	.17	.17	.17	.68
2012	.175	.175	.18	.18	.71
2013	.18	.18	.19	.19	.74
2014	.19	.19	.20	.22	.80
2015	.22	.22			

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 18.7% of net income in 2014), International Propane (14.3%), Gas Utility (35.2%), Midstream & Marketing (34.9%), and Corp. & Other less than -3%. UGI Utilities distributes netural gas and electricity to over 600,000 customers mainly in Pennsylvania; 26%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Wellington Management Co. holds 10.8% of stock; officers/directors, 2.4% (12/14 proxy). Has 8,400 empls. CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Telephone: 610-337-1000. Internet: www.ugicorp.com.

UGI Corp.'s financial results could certainly be better this year. Indeed, the company's March-period top line declined more than 22%. This downturn reflected lower contributions from the AmeriGas Propane, UGI International, Gas Utility, and Midstream & Marketing segments. The weak revenues can largely be attributed to the year-over-year decline in propane and natural gas pricing as well as from reduced retail gallons sold at the AmeriGas Propane unit. On the profitability front, operating & administrative costs increased 340 basis points as a percentage of the top line. This was largely offset by the sharp reduction in cost of sales. On balance, UGI's bottom line remained unchanged when compared to 2014's figure, at $1.23 a share. This was relatively in line with our earlier call.

Consequently, we have left our 2015 and 2016 share-net estimates unchanged for the time being. In fiscal 2015 (ends September 30th) this would represent a modest 1.5% annual increase. This ought to be supported by the regulated gas utility division, which has added approximately 11,000 new heating customers over the first six months of fiscal 2015.

A number of capital projects and an acquisition augur well for long-term prospects. The PennEast pipeline project is progressing nicely through the FERC preapproval process. That 100-plus-mile expansion will link the Northeast, PA Marcellus region with major customer markets in Pennsylvania and New Jersey. Meanwhile, UGI recently announced plans for a 1,000-megawatt plant in Sunbury, PA and a 1,300-megawatt plant in Jessup, PA, know as Sunbury and Invenergy, respectively. All of those facilities are expected to be operational in late 2017. Too, the $400 million-$450 million (EUR) purchase of the Total LPG Distribution business in France (Totalgaz) received final regulatory approval from the French Competition Authority. This deal should help to grow UGI's geographic footprint.

These shares are ranked to outpace the broader market averages. However, the dividend yield is somewhat below average for a utility, and the equity is trading above our Target Price Range, thus limiting appreciation potential.

Bryan J. Fong *June 5, 2015*

(A) Fiscal year ends Sept. 30. Quarlarly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. items: '99, 13¢; '01, d1¢; '03, 22¢; '04, d6¢; '05, 3¢; '06, 5¢; '07, 12¢. Next egs. report due late July. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/14: $3,409.5 mill., $19.73/sh. (E) In mill., adjusted for stock splits.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	75
Earnings Predictability	75

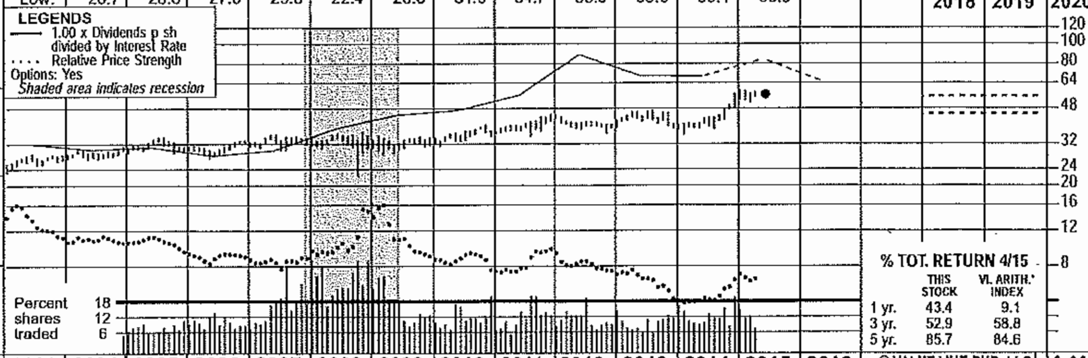
WGL HOLDINGS NYSE-WGL

RECENT PRICE 56.17 | P/E RATIO 19.2 (Trailing: 18.5; Median: 15.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Raised 3/27/15
SAFETY 1 Raised 4/2/93
TECHNICAL 4 Lowered 5/15/15
BETA .80 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	31.4	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0	47.0	56.8	59.1
Low:	26.7	28.8	27.0	29.8	22.4	28.6	31.0	34.7	36.0	38.0	35.4	50.9

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(Nil)	3%
Low	45	(-20%)	-1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	1
to Sell	0	1	0	0	0	2	0	1	1

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	93	99	94
to Sell	86	84	116
Hld's(000)	34353	34118	31806

% TOT. RETURN 4/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	43.4	9.1
3 yr.	52.9	58.8
5 yr.	85.7	84.6

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	47.07	47.70	53.73	53.00	54.00	Revenues per sh A	59.00
2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	4.53	4.29	4.83	5.00	5.20	"Cash Flow" per sh	5.60
1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	2.31	2.68	2.90	3.00	Earnings per sh B	3.35
1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	1.59	1.66	1.72	1.85	1.87	Div'ds Decl'd per sh C■	1.99
3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	4.87	6.04	7.63	5.00	5.00	Cap'l Spending per sh	5.00
14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.89	22.82	23.49	24.64	24.65	24.08	24.30	25.40	Book Value per sh D	29.20
46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	51.52	51.70	51.76	50.00	50.00	Common Shs Outst'g E	50.00
17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	15.3	18.2	15.2	Bold figures are		Avg Ann'l P/E Ratio	15.0
.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.97	1.02	.80	Value Line		Relative P/E Ratio	.95
4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	3.9%	3.9%	4.2%	estimates		Avg Ann'l Div'd Yield	4.0%
						2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	2466.1	2780.9	2650	2700	Revenues ($mill) A	2950
						104.8	96.0	102.9	122.9	128.7	115.0	115.5	138.4	119.7	139.0	145	150	Net Profit ($mill)	170
						37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	40.1%	30.2%	29.0%	39.0%	39.0%	Income Tax Rate	39.0%
						4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	5.7%	4.9%	5.0%	5.4%	5.5%	Net Profit Margin	5.7%
						39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	31.2%	28.7%	34.8%	32.5%	31.5%	Long-Term Debt Ratio	29.0%
						58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	67.3%	69.8%	63.8%	66.0%	67.0%	Common Equity Ratio	70.0%
						1478.1	1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	1886.9	1826.8	1954.0	1845	1900	Total Capital ($mill)	2090
						1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	2907.5	3314.4	3850	4470	Net Plant ($mill)	7000
						8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	7.5%	8.1%	9.0%	9.0%	Return on Total Cap'l	9.0%
						11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	10.7%	9.2%	10.9%	12.0%	12.0%	Return on Shr. Equity	11.5%
						12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	10.8%	9.3%	11.0%	12.0%	12.0%	Return on Com Equity	11.5%
						4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	4.8%	2.6%	4.3%	4.5%	4.5%	Retained to Com Eq	4.5%
						62%	69%	66%	57%	57%	67%	64%	56%	72%	62%	64%	62%	All Div'ds to Net Prof	59%

CAPITAL STRUCTURE as of 3/31/15
Total Debt $1170.5 mill. Due in 5 Yrs $95.0 mill.
LT Debt $950.5 mill. LT Interest $37.7 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x) (42% of Total Capital)
Pension Assets-9/14 $1,244.3 mill. Oblig. $1,260.3 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 49,728,662 shs. as of 4/30/15

MARKET CAP: $2.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2013	2014	3/31/15
Cash Assets	3.5	8.8	9.3
Other	816.5	826.7	915.0
Current Assets	820.0	835.5	924.3
Accts Payable	270.7	313.2	324.1
Debt Due	440.1	473.5	220.0
Other	239.3	233.6	357.0
Current Liab.	950.1	1020.3	901.1
Fix. Chg. Cov.	535%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	2.5%	-1.5%	3.0%
"Cash Flow"	2.5%	1.5%	3.5%
Earnings	3.5%	1.5%	4.5%
Dividends	2.5%	3.0%	3.0%
Book Value	4.0%	3.0%	3.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	727.7	839.4	438.3	419.8	2425.3
2013	686.7	891.4	478.1	409.9	2466.1
2014	680.5	1174.0	467.5	458.9	2780.9
2015	749.2	1001.7	475	424.1	2650
2016	765	1015	485	435	2700

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2012	1.13	1.58	.08	d.11	2.68
2013	1.14	1.75	d.03	d.55	2.31
2014	.99	1.84	.02	d.17	2.68
2015	1.16	2.02	Nil	d.28	2.90
2016	1.18	2.04	.03	d.25	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.378	.39	.39	.39	1.55
2012	.39	.40	.40	.40	1.59
2013	.40	.42	.42	.42	1.66
2014	.42	.44	.44	.44	1.74
2015	.463	.463			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,117,043 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy-related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century owns 9.4% of common stock; Off./dir. less than 1% (1/15 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted mixed financial results for its fiscal second quarter. On the downside, revenues declined 14.7% on a year-over-year basis, to about $1.0 billion. This reflected a downturn in utility and nonutility volumes of 13.6% and 16.3%, respectively. The bulk of this reduction stemmed from the lower natural gas and fuel prices when compared to the prior-year figure. On balance, wider margins were sufficient enough to offset the reduced volumes, and WGL's bottom line advanced 10%, to $2.02 a share. This was higher than our earlier expectation.

As a result, we have added a dime to our fiscal 2015 earnings estimate, to $2.90 a share. This would represent an annual profit increase of about 8%. WGL's regulated utility operations have added about 12,800 active customer meters over the past year. Additional benefits should stem from healthy gains at the Retail Energy Marketing division as overall economic factors aid that unit's performance this year. Alternatively, the Commercial Energy Systems and Midstream Energy Services segments have been facing a difficult operating environment of late and will likely remain a drag on overall operations for the immediate future.

A recently announced supply agreement could provide customers with cost savings. WGL is in the process of investing $126 million with Energy Corporation of America (ECA) to acquire natural gas reserves through some of ECA's currently producing wells in PA. The pending deal needs to be approved by the Virginia State Corporation Commission. However, assuming it goes through, the deal should help to reduce gas prices and related volatility over the next 20 years.

Capital projects augur well for prospects. Some of the more noteworthy ones currently in the works are the Constitution Pipeline, Central Penn Line, and Mountain Valley Pipeline. These projects should widen the company's geographic reach and boost overall capacity.

All told, these shares offer modest appeal to conservative, income-seeking accounts. Meantime, they are ranked to mirror the broader market averages in the year ahead. And there is little 3- to 5-year appreciation potential.

Bryan J. Fong *June 5, 2015*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late July.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '14: $720.5 million, $14.49/sh.
(E) In millions.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	80

WATER UTILITY INDUSTRY

The Water Utility Industry consists of nine stocks, eight of which are regulated entities. The structure of the water utility market varies widely from that of the electric utility model.

Drought conditions in California continue to bring attention to this sector.

Most utilities deferred doing major overhauls of their aging infrastructure for the past few decades. As a result, many are now spending to replace old pipelines as well as meet all EPA standards.

The industry ranks 40 out the 96 that *Value Line* follows. This is up from 64 at the time of our last April report.

The American Water Utility Market

Many investors assume that the water utilities are similar to their electric generating counterparts. Both need regulatory approval for the prices they charge customers, but otherwise the two industries can be very different. For example, most electric power companies are publicly traded. Conversely, it takes almost 53,000 municipally-owned water systems to service about 300 million Americans. If we included the small and very small systems, which are classified as serving 25 to 500 people, the number of water districts soars above 150,000. The remaining water is supplied by only about 10 or so companies that issue stock and can be owned by private investors. Of the eight we follow, four have a market capitalization of over $1 billion, with the remaining four averaging about $500 million. The total is about $19 billion or equal to the market cap of one very large electric utility, such as Con Edison.

The small number of public companies limits the amount investors can participate in this industry. Indeed, water stocks' P/E's are much higher than electric utilities. This is probably due to accounts willing to pay a premium to diversify into another regulated industry, which is relatively stable. Another reason is that regulators appear to have fewer conflicts with water companies compared to the electric utilities. In the residential sector, water bills are almost always lower than electricity bills. Thus, any increase is coming from a low base and the impact isn't as substantial.

California's Long Drought

The state remains short on water as a result of an historic lack of rainfall. Governor Brown has had to implement a new policy intended to get urban dwellers to reduce water consumption 25%. For customers going over their limit, much higher rates and penalties will be applied. For investors, the two main questions are "What will happen when a utility experiences a 25% drop in demand?." And, "Are there any regulated water businesses that would benefit from the present environment?" The answer to both questions is "No". California regulators have worked in tandem with the three companies we follow that operate in the state. They had already changed the methodology on how utilities generate profits. By introducing decoupling, a water company can do fine even when there is a sharp decline in sales. This gets everyone on the same page. A water operator receives more of a service fee. Conservation can be pushed hard and the water utilities won't have to take a hit. As we mentioned earlier, all of the regulated corporations would never be allowed to enjoy windfall profits at the expense of the service area (which is also populated with people who vote.)

INDUSTRY TIMELINESS: 40 (of 96)

The one company that could benefit from the shortage of water is *Consolidated Water*. It is publicly traded and is not regulated. As a builder and operator of desalination plants, it is well positioned to provide many countries in the world with potable water. The one negative is that *Consolidated* is a very small company with a market capitalization of between $175 million and $200 million.

Large Construction Programs

Years of deferring expenditures to maintain pipelines, wastewater facilities, and other structures has left the water infrastructure in the U.S. in very poor condition. Just about every company we follow is in the midst of a major construction program aimed at replacing and upgrading these assets. Fortunately, regulars have been working with the utilities, enabling them to earn a reasonably return on their investments. Moreover, as a whole, the industry has been able to maintain its financial integrity by not issuing too much debt. And, even though these capital expenditures will be ongoing, we are not worried about any of the companies, at this point.

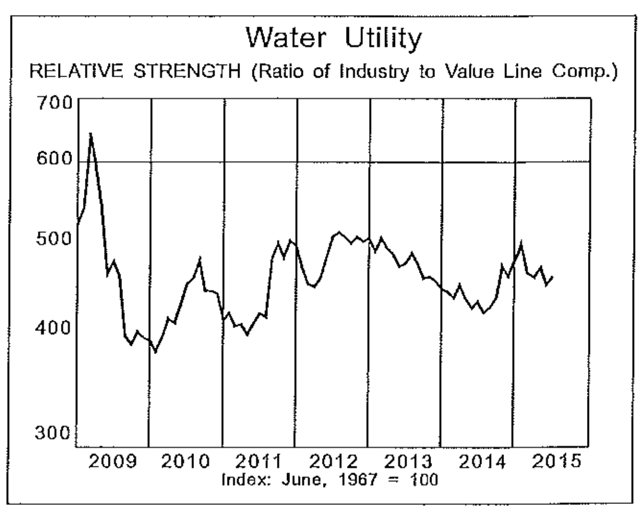
Conclusion

In this group, *American States Water* and *American Water Works* are ranked to outperform the market in the year ahead. These are the two largest companies in the industry. Both have at least average finances and better-than-average long-term dividend growth prospects. Another positive is that the dividend yield spread between the upper and lower end on stocks in the industry is very tight. This means that the quality equities are cheap on a relative basis.

The other six regulated water companies are neutrally ranked. *Consolidated Water*, which we mentioned earlier, currently is not timely.

Income-oriented investors may also like group. The average yield is around 2.6%, which is 50 basis points higher the average stock in the *Value Line* universe.

James A. Flood



AMER. STATES WATER NYSE-AWR

RECENT PRICE 39.76 | P/E RATIO 24.0 (Trailing: 25.5 Median: 21.0) | RELATIVE P/E RATIO 1.24 | DIV'D YLD 2.2% | VALUE LINE

TIMELINESS 3 Lowered 5/16/14
SAFETY 2 Raised 7/20/12
TECHNICAL 2 Raised 4/3/15
BETA .70 (1.00 = Market)

High:	13.4	17.3	21.9	23.1	21.0	19.4	19.8	18.2	24.1	33.1	38.7	41.7			Target Price Range		
Low:	10.4	12.2	15.1	16.8	13.5	14.9	15.6	15.3	17.0	24.0	27.0	36.9			2018	2019	2020

2018-20 PROJECTIONS

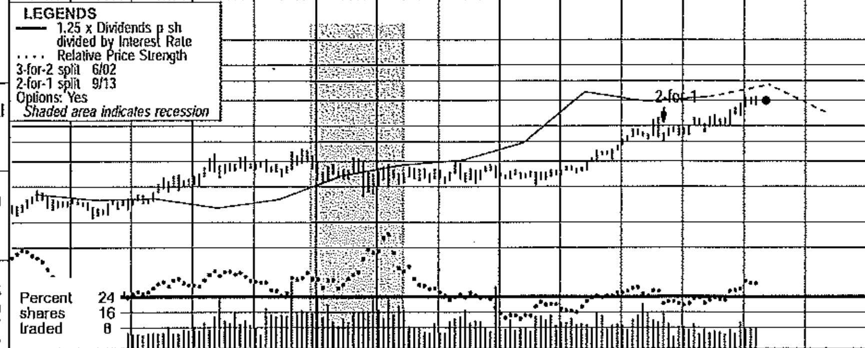
	Price	Gain	Ann'l Total Return
High	50	(+25%)	8%
Low	35	(-10%)	Nil

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	1
to Sell	0	1	0	0	1	0	3	0	1

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	96	81	99
to Sell	68	86	87
Hld's(000)	23236	23032	23380



% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.7	7.7
3 yr.	139.9	57.2
5 yr.	165.6	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
6.45	6.08	6.53	6.89	6.99	6.81	7.03	7.88	8.75	9.21	9.74	10.71	11.12	12.12	12.19	12.17	*12.35*	*13.35*	Revenues per sh	*15.35*
1.13	1.10	1.26	1.27	1.04	1.11	1.32	1.45	1.65	1.69	1.70	2.11	2.13	2.48	2.65	2.65	*2.70*	*2.80*	"Cash Flow" per sh	*3.70*
.60	.64	.67	.67	.39	.53	.66	.67	.81	.78	.81	1.11	1.12	1.41	1.61	1.57	*1.60*	*1.65*	Earnings per sh A	*2.15*
.43	.43	.43	.44	.44	.44	.45	.46	.48	.50	.51	.52	.55	.64	.76	.83	*.88*	*.93*	Div'd Decl'd per sh B■	*1.12*
2.15	1.51	1.59	1.34	1.88	2.51	2.12	1.95	1.45	2.23	2.09	2.12	2.13	1.77	2.52	1.90	*2.05*	*2.10*	Cap'l Spending per sh	*2.40*
5.91	6.37	6.61	7.02	6.98	7.51	7.86	8.32	8.77	8.97	9.70	10.13	10.84	11.80	12.72	13.24	*13.80*	*14.25*	Book Value per sh	*15.45*
26.87	30.24	30.24	30.36	30.42	33.50	33.60	34.10	34.46	34.60	37.06	37.26	37.70	38.53	38.72	38.29	*38.00*	*37.50*	Common Shs Outst'g C	*37.50*
17.1	15.9	16.7	18.3	31.9	23.2	21.9	27.7	24.0	22.6	21.2	15.7	15.4	14.3	17.2	22.2	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
.97	1.03	.86	1.00	1.82	1.23	1.17	1.50	1.27	1.36	1.41	1.00	.97	.91	.97	1.17	*Value Line*		Relative P/E Ratio	*1.30*
4.2%	4.2%	3.9%	3.6%	3.5%	3.6%	3.1%	2.5%	2.5%	2.9%	2.9%	3.0%	3.2%	3.1%	2.7%	2.4%	*estimates*		Avg Ann'l Div'd Yield	*2.7%*
						236.2	268.6	301.4	318.7	361.0	398.9	419.3	466.9	472.1	465.8	*470*	*500*	Revenues ($mill)	*575*
						22.5	23.1	28.0	26.8	29.5	41.4	42.0	54.1	62.7	61.1	*61.0*	*62.5*	Net Profit ($mill)	*80.0*
						47.0%	40.5%	42.6%	37.8%	38.9%	43.2%	41.7%	39.9%	36.3%	38.4%	*38.5%*	*38.0%*	Income Tax Rate	*38.0%*
						--	12.2%	8.5%	6.9%	3.2%	5.8%	2.0%	2.5%	2.5%	.5%	*.5%*	*1.0%*	AFUDC % to Net Profit	*2.0%*
						50.4%	48.6%	46.9%	46.2%	45.9%	44.3%	45.4%	42.2%	39.8%	39.1%	*41.0%*	*43.0%*	Long-Term Debt Ratio	*42.0%*
						49.6%	51.4%	53.1%	53.8%	54.1%	55.7%	54.6%	57.8%	60.2%	60.9%	*59.0%*	*57.0%*	Common Equity Ratio	*58.0%*
						532.5	551.6	569.4	577.0	665.0	677.4	749.1	787.0	818.4	832.6	*890*	*935*	Total Capital ($mill)	*1070*
						713.2	750.6	776.4	825.3	866.4	855.0	896.5	917.8	981.5	1003.5	*1060*	*1120*	Net Plant ($mill)	*1240*
						5.4%	6.0%	6.7%	6.4%	5.9%	7.6%	7.1%	8.3%	8.9%	8.6%	*9.0%*	*8.5%*	Return on Total Cap'l	*8.5%*
						8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	11.9%	12.7%	12.1%	*11.5%*	*11.5%*	Return on Shr. Equity	*13.0%*
						8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	11.9%	12.7%	12.1%	*11.5%*	*11.5%*	Return on Com Equity	*13.0%*
						2.8%	2.7%	3.9%	3.1%	3.2%	5.8%	5.3%	6.6%	6.8%	5.6%	*5.0%*	*5.0%*	Retained to Com Eq	*6.0%*
						67%	67%	58%	64%	61%	47%	49%	45%	47%	53%	*55%*	*56%*	All Div'ds to Net Prof	*52%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $326.1 mill. Due in 5 Yrs $41.6 mill.
LT Debt $325.8 mill. LT Interest $21.5 mill.
(LT interest earned: 5.7 x: total interest coverage: 5.4 x) (39% of Cap'l)
Leases, Uncapitalized: Annual rentals $0.4 mill.
Pension Assets-12/14 $140.6 mill. **Oblig.** $185.2 mill.

Pfd Stock None.

Common Stock 38,220,567 shs. as of 2/23/15

MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	23.5	38.2	76.0
Other	160.5	153.4	133.5
Current Assets	184.0	191.6	209.5
Accts Payable	40.6	49.8	41.9
Debt Due	3.3	6.3	.3
Other	49.8	44.8	57.1
Current Liab.	93.7	100.9	99.3
Fix. Chg. Cov.	488%	531%	533%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	5.5%	6.5%	4.0%
"Cash Flow"	7.5%	8.5%	6.0%
Earnings	9.0%	13.0%	6.5%
Dividends	4.0%	6.5%	8.0%
Book Value	5.5%	6.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	107.6	114.3	133.5	111.5	466.9
2013	110.6	120.7	130.9	109.9	472.1
2014	102.0	115.6	138.3	109.9	465.8
2015	*103*	*117*	*140*	*110*	*470*
2016	*105*	*125*	*150*	*120*	*500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.27	.40	.49	.26	1.41
2013	.35	.43	.53	.30	1.61
2014	.28	.39	.54	.36	1.57
2015	*.30*	*.45*	*.55*	*.30*	*1.60*
2016	*.31*	*.46*	*.57*	*.31*	*1.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.13	.14	.14	.14	.55
2012	.14	.14	.1775	.1775	.64
2013	.1775	.1775	.2025	.2025	.76
2014	.2025	.2025	.213	.213	.83
2015	.213				

BUSINESS: American States Water Co. operates as a holding company. Through its principal subsidiary, Golden States Water Company, it supplies water to 258,191 customers in 75 communities and 10 counties. Service areas include the greater metropolitan areas of Los Angeles and Orange Counties. The company also provides electric utility services to 23,716 customers in the city of Big Bear Lake and in areas of San Bernardino County. Sold Chaparral City Water of Arizona (6/11). Has 707 employees. Blackrock, Inc., owns 9.8% of out. shares; Vanguard, 8.5%; off. & dir. 1.5%. (4/15 Proxy). Chairman: Lloyd Ross. President & CEO: Robert J. Sprowls. Inc: CA. Addr: 630 East Foothill Boulevard, San Dimas, CA 91773. Tel: 909-394-3600. Internet: www.aswater.com.

American States Water's earnings growth should be modest through 2016. The company's main subsidiary, Golden State Water Co., has been coming close to earning the allowable return on its common equity for the past two years. Thus, there isn't much room for bottom-line expansion in the near term. All told, we only expect share net to increase 2% this year, followed by a 3% increase in 2016.

Growth in the military business should bolster long-term profits. Through its ASUS subsidiary, the company provides water to nine armed forces bases under six 50-year contracts. This operation, in which returns are not capped by state regulators, has been responsible for 20% to 25% of American States' share earnings. Over the next five years, up to 50 more bases may privatize their water and wastewater systems. As ASUS has performed successfully in this sector, we expect it to win a proportionate amount of these contracts.

Operating in California has not been a negative for the company. Regulators in the state have worked well with the industry in response to the record-breaking drought now plaguing the region. Usually, a decrease in water usage translates into reduced revenues for a utility, making conservation almost not in their interest. In a process known as decoupling, GSWC is allowed to structure fees that result in it not being penalized to incentivize households to use less water. Indeed, over the past six years, water usage has declined 16%-17%. Moreover, California permits utilities to collect increased expenses as they are incurred, not after the fact, as many other state regulators require.

Management believes that a 5% dividend growth rate is sustainable over the next 3- to 5-year period. Though this is below historical levels, the expected increase in the annual payout is not far off the industry average. With the help from nonregulated businesses, we think there is potential upside to this figure.

American Water shares do not stand out for either short- or long-term potential performance. The stock's strong showing has eliminated much of its attractiveness.

James A. Flood *April 17, 2015*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, 7¢; '05, 13¢; '06, 3¢; '08, (14¢); '10, (23¢) '11, 10¢. Next earnings report due mid-May. Quarterly earnings may not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	70
Earnings Predictability	85

AMERICAN WATER NYSE-AWK

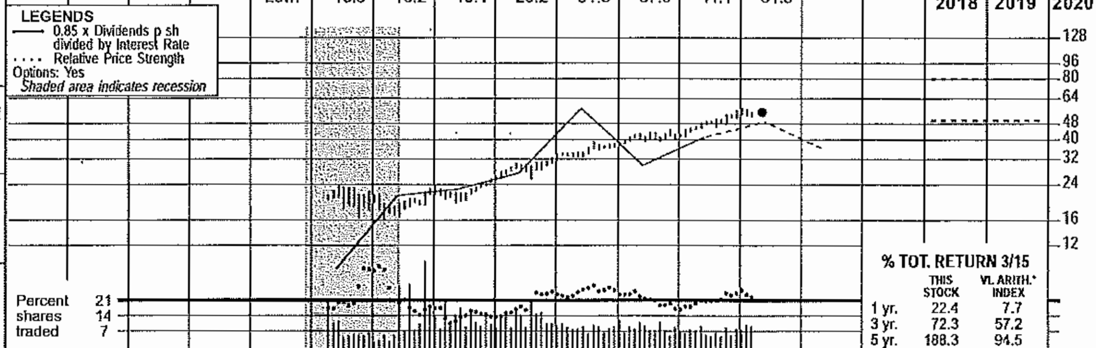
RECENT PRICE 54.68 | P/E RATIO 20.5 (Trailing: 23.0, Median: NMF) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 2.4% | VALUE LINE

	2008	2009	2010	2011	2012	2013	2014	2015
High:	23.7	23.0	25.8	32.8	39.4	45.1	56.2	57.5
Low:	16.5	16.2	19.4	25.2	31.3	37.0	41.1	51.8

Target Price Range 2018 | 2019 | 2020

TIMELINESS 2 Raised 1/23/15
SAFETY 3 New 7/25/08
TECHNICAL 2 Raised 4/10/15
BETA .70 (1.00 = Market)

LEGENDS
— 0.85 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+45%)	12%
Low	50	(-10%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	3	0	0	4	0	0	3	0	0
to Sell	3	0	0	6	0	0	3	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	208	206	223
to Sell	194	189	201
Hld's(000)	146101	146606	143322

Percent shares traded 21 14 7

% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.4	7.7
3 yr.	72.3	57.2
5 yr.	188.3	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008E	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	--	--	--	--	--	13.08	13.84	14.61	13.98	15.49	15.18	16.25	16.28	16.78	17.70	18.50	Revenues per sh	21.40
--	--	--	--	--	--	--	.65	d.47	2.87	2.89	3.56	3.73	4.27	4.36	4.75	4.65	5.10	"Cash Flow" per sh	6.15
--	--	--	--	--	--	--	d.97	d2.14	1.10	1.25	1.53	1.72	2.11	2.06	2.39	2.60	2.80	Earnings per sh A	3.25
--	--	--	--	--	--	--	--	--	.40	.82	.86	.91	1.21	.84	1.21	1.33	1.42	Div'd Decl'd per sh B■	1.70
--	--	--	--	--	--	--	4.31	4.74	6.31	4.50	4.38	5.27	5.25	5.50	5.33	5.55	5.55	Cap'l Spending per sh	6.25
--	--	--	--	--	--	--	23.86	28.39	25.64	22.91	23.59	24.11	25.11	26.52	27.39	27.60	29.00	Book Value per sh D	34.55
--	--	--	--	--	--	--	160.00	160.00	160.00	174.63	175.00	175.66	176.99	178.25	179.46	179.50	179.50	Common Shs Outst'g C	185.00
--	--	--	--	--	--	--	--	--	18.9	15.6	14.6	16.8	16.7	19.9	20.1	Bold figures are		Avg Ann'l P/E Ratio	20.0
--	--	--	--	--	--	--	--	--	1.14	1.04	.93	1.05	1.06	1.12	1.06	Value Line		Relative P/E Ratio	1.25
--	--	--	--	--	--	--	--	--	1.9%	4.2%	3.8%	3.1%	3.4%	2.0%	2.5%	estimates		Avg Ann'l Div'd Yield	2.6%

CAPITAL STRUCTURE as of 12/31/14
Total Debt $5959.3 mil. Due in 5 Yrs $1294.5 mil.
LT Debt $5448.2 mil. LT Interest $278.0 mil.
(Total interest coverage: 3.0x) (53% of Cap'l)

Leases, Uncapitalized: Annual rentals $14.0 mill.
Pension Assets 12/14 $1428.2 mill Oblig. $1746.5 mill.
Pfd Stock $17.2 mill. Pfd Div'd $.5 mill

Common Stock 179,787,780 shs. as of 2/19/2015

MARKET CAP: $9.8 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
--	2093.1	2214.2	2336.9	2440.7	2710.7	2666.2	2876.9	2901.9	3011.3	3175	3325	Revenues ($mill)	3960
--	d155.8	d342.3	187.2	209.9	267.8	304.9	374.3	369.3	429.8	465	505	Net Profit ($mill)	600
--	--	--	37.4%	37.9%	40.4%	39.5%	40.7%	39.1%	39.4%	39.5%	38.5%	Income Tax Rate	37.5%
--	--	--	--	--	--	--	6.2%	5.1%	1.4%	5.0%	5.0%	AFUDC % to Net Profit	6.0%
--	56.1%	50.9%	53.1%	56.9%	56.8%	55.7%	53.9%	52.4%	52.4%	53.5%	53.0%	Long-Term Debt Ratio	55.0%
--	43.9%	49.1%	46.9%	43.1%	43.2%	44.2%	46.1%	47.6%	47.4%	46.5%	47.0%	Common Equity Ratio	45.0%
--	8692.8	9245.7	8750.2	9289.0	9561.3	9580.3	9635.5	9940.7	10363.8	10955	11500	Total Capital ($mill)	13300
--	8720.6	9318.0	9991.8	10524	11059	11021	11739	12391	13029.3	13600	14250	Net Plant ($mill)	15000
--	NMF	NMF	3.7%	3.8%	4.4%	4.8%	5.4%	5.1%	5.5%	5.0%	5.5%	Return on Total Cap'l	6.0%
--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	7.8%	8.7%	8.5%	8.5%	Return on Shr. Equity	9.0%
--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	7.8%	8.7%	8.5%	8.5%	Return on Com Equity	9.0%
--	NMF	NMF	3.0%	1.8%	2.8%	3.5%	3.6%	4.7%	4.3%	4.0%	4.5%	Retained to Com Eq	4.5%
--	--	--	34%	65%	56%	52%	57%	40%	51%	53%	51%	All Div'ds to Net Prof	51%

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	24.4	27.0	23.1
Other	475.0	523.3	638.3
Current Assets	499.4	550.3	661.4
Accts Payable	279.6	264.1	285.8
Debt Due	385.9	644.5	511.1
Other	329.3	326.9	444.1
Current Liab.	994.8	1235.5	1241.0
Fix. Chg. Cov.	297%	307%	300%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	--	3.0%	4.5%
"Cash Flow"	--	32.5%	6.0%
Earnings	--	--	7.5%
Dividends	--	--	8.0%
Book Value	--	-.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	618.5	745.6	831.8	681.0	2876.9
2013	636.1	724.3	829.2	712.3	2901.9
2014	679.0	754.8	846.1	731.4	3011.3
2015	700	805	880	790	3175
2016	735	840	920	830	3325

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.28	.66	.87	.30	2.11
2013	.32	.57	.84	.33	2.06
2014	.39	.62	.86	.52	2.39
2015	.45	.70	1.00	.45	2.60
2016	.50	.75	1.05	.50	2.80

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.22	.23	.23	.23	.91
2012	.23	.23	.25	.50	1.21
2013	--	.28	.28	.28	.84
2014	.28	.31	.31	.31	1.21
2015	.31				

BUSINESS: American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to over 15 million people in over 47 states and Canada. (Regulated presence in 16 states.) Nonregulated business assists municipalities and military bases with the maintenance and upkeep as well. Regulated operations made up 88.8% of 2014 revenues. New Jersey is its largest market accounting for 22.7% of regulated revenues. Has roughly 6,400 employees. BlackRock, Inc., owns 10.0% of outstanding shares; Vanguard, 6.3%; officers & directors, less than 1.0%. (4/14 Proxy). Pres. & CEO: Susan Story. Chairman: George Mackenzie. Addr.: 1025 Laural Oak Road, Voorhees, NJ 08043. Tel.: 856-346-8200. Internet: www.amwater.com.

American Water Works recently completed another successful year. Thanks to a strong fourth quarter, the company posted a hefty 16% year-over-year share-net gain in 2014.

We expect this trend to continue. One of the strengths of American Water is in its ability to make many small tuck-in acquisitions and integrate them into existing operations. In addition to the synergies realized from these purchases, management continues to place a significant emphasis on driving down costs. (Last year's key expense ratio fell from 38.5% to 36.7%.) Since, like most members of this industry, the company needs to make large expenditures to improve its infrastructure, it will have to spend roughly $1 billion annually for the foreseeable future. Higher investment increases American Water's assets that it is allowed to earn a return on. Though comparison with last year's impressive results will be difficult, we expect the company to record healthy earnings-per-share gains of 8% in both 2015 and 2016.

American Water stands out in comparison to most of its peers. For starters, this is a market in which size matters. AWK's market capitalization represents more than half that of all of the nine stocks in this industry combined. As smaller municipally-run water districts realize that they don't have the financial wherewithal required to maintain their systems, American Water should be the main beneficiary. As the largest buyer of pipes, meters, etc., it is able to get better pricing. Moreover, being so diversified geographically, the utility already is familiar with all federal and state regulations.

The balance sheet should remain about average. American Water probably won't be able to generate sufficient cash to cover its large construction budget through late decade. So, more debt will be required. As a result, we don't expect the Financial Strength rating to be raised.

These shares are ranked to outperform the market averages in the year ahead. But despite all of the company's positive attributes, the equity's total return potential through 2016-2018 is below average for the typical stock in the *Value Line* universe.

James A. Flood *April 17, 2015*

(A) Diluted earnings. Excludes nonrecurring losses: '08, $4.62; '09, $2.63; '11, $0.07. Discontinued operations: '06, ($0.04); '11, $0.03; '12, ($0.10); '13,($0.01); '14, ($0.05). Next earnings report due early May. Quarterly earnings may not sum due to rounding. (B) Dividends paid in March, June, September, and December. ■ Div. reinvestment available. Two payments made in 4th quarter of 2012. (C) In millions. (D) Includes intangibles. In 2014: $1.21 billion, $6.73/share. (E) Pro forma numbers for '06 & '07.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	20

AQUA AMERICA NYSE-WTR

RECENT PRICE 26.81 | P/E RATIO 21.6 (Trailing: 22.2 Median: 24.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 3 Lowered 5/24/13
SAFETY 2 Raised 4/20/12
TECHNICAL 2 Raised 4/3/15
BETA .70 (1.00 = Market)

	High	Low
2004	14.8	11.3
2005	23.4	14.0
2006	23.8	16.1
2007	21.3	15.1
2008	17.6	9.8
2009	17.2	12.3
2010	18.4	13.2
2011	19.0	15.4
2012	21.5	16.8
2013	28.1	20.6
2014	28.2	22.4
2015	28.1	25.4

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

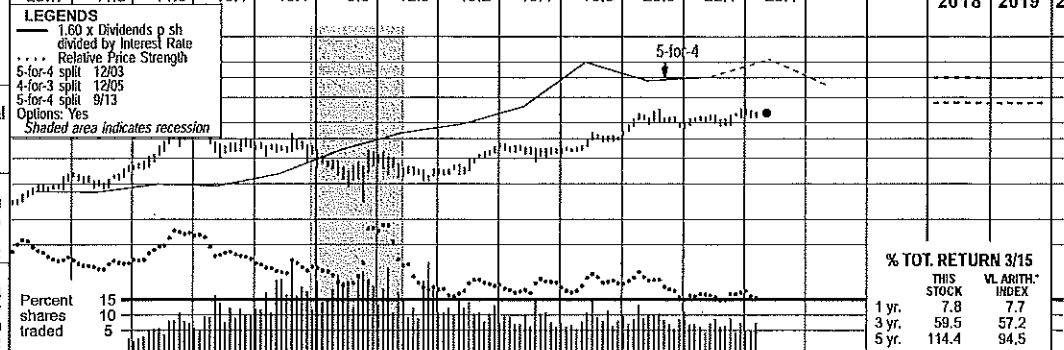
	Price	Gain	Ann'l Total Return
High	40	(+50%)	13%
Low	30	(+10%)	6%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	2	1	0	1	0	0	2	1	1
to Sell	3	1	1	2	1	2	5	2	2

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	127	139	137
to Sell	133	126	140
Hld's(000)	81999	80311	81382



% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.8	7.7
3 yr.	59.5	57.2
5 yr.	114.4	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
1.93	1.97	2.16	2.28	2.38	2.78	3.08	3.23	3.61	3.71	3.93	4.21	4.10	4.32	4.32	4.37	*4.55*	*4.70*	Revenues per sh	*5.70*
.58	.61	.69	.76	.77	.87	.97	1.01	1.10	1.14	1.29	1.42	1.45	1.51	1.82	*1.90*	*2.35*	*2.50*	"Cash Flow" per sh	*3.05*
.33	.37	.41	.43	.46	.51	.57	.56	.57	.58	.62	.72	.83	.87	1.16	1.20	*1.25*	*1.30*	Earnings per sh A	*1.65*
.22	.23	.24	.26	.28	.29	.32	.35	.38	.41	.44	.47	.50	.54	.58	.63	*.71*	*.77*	Div'd Decl'd per sh B■	*.98*
.72	.93	.87	.96	1.06	1.23	1.47	1.64	1.43	1.58	1.66	1.89	1.90	1.98	1.73	1.84	*1.95*	*2.00*	Cap'l Spending per sh	*2.00*
2.74	3.08	3.32	3.49	4.27	4.71	5.04	5.57	5.85	6.26	6.50	6.81	7.21	7.90	8.63	9.27	*9.65*	*10.05*	Book Value per sh	*11.40*
133.50	139.78	142.47	141.49	154.31	158.97	161.21	165.41	166.75	169.21	170.61	172.46	173.60	175.43	177.93	178.59	*176.50*	*175.00*	Common Shs Outst'g C	*170.00*
21.2	18.2	23.6	23.6	24.5	25.1	31.8	34.7	32.0	24.9	23.1	21.1	21.3	21.9	21.2	20.2	*Bold figures are*		Avg Ann'l P/E Ratio	*21.5*
1.21	1.18	1.21	1.29	1.40	1.33	1.69	1.87	1.70	1.50	1.54	1.34	1.34	1.39	1.19	1.06	*Value Line*		Relative P/E Ratio	*1.35*
3.0%	3.3%	2.5%	2.5%	2.5%	2.3%	1.8%	1.8%	2.1%	2.8%	3.1%	3.1%	2.8%	2.8%	2.4%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*2.6%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $1630.7 mill. Due in 5 Yrs $436.9 mill.
LT Debt $1560.7 mill. LT Interest $70.0 mill.
(Total interest coverage: 3.9x) (49% of Cap'l)

Pension Assets-12/14 232.4 mill. Oblig. $281.2 mill.

Pfd Stock None

Common Stock 176,823,519 shares as of 2/12/15

MARKET CAP: $4.7 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
496.8	533.5	602.5	627.0	670.5	726.1	712.0	757.8	768.6	779.9	*800*	*825*	Revenues ($mill)	*970*
91.2	92.0	95.0	97.9	104.4	124.0	144.8	153.1	205.0	213.9	*225*	*230*	Net Profit ($mill)	*280*
38.4%	39.6%	38.9%	39.7%	39.4%	39.2%	32.9%	39.0%	10.0%	*10.5%*	*18.0%*	*20.0%*	Income Tax Rate	*27.0%*
--	--	--	--	--	--	--	--	1.1%	2.4%	*2.0%*	*2.5%*	AFUDC % to Net Profit	*3.0%*
52.0%	51.6%	55.4%	54.1%	55.6%	56.6%	52.7%	52.7%	48.9%	48.5%	*49.5%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
48.0%	48.4%	44.6%	45.9%	44.4%	43.4%	47.3%	47.3%	51.1%	51.5%	*50.5%*	*50.0%*	Common Equity Ratio	*50.0%*
1690.4	1904.4	2191.4	2306.6	2495.5	2706.2	2646.8	2929.7	3003.6	3216.1	*3370*	*3505*	Total Capital ($mill)	*3955*
2280.0	2506.0	2792.8	2997.4	3227.3	3469.3	3612.9	3936.2	4167.3	4402.0	*4550*	*4700*	Net Plant ($mill)	*5000*
6.9%	6.4%	5.9%	5.7%	5.6%	5.9%	6.9%	6.6%	8.0%	7.5%	*8.0%*	*7.5%*	Return on Total Cap'l	*8.5%*
11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	13.4%	12.9%	*13.0%*	*13.0%*	Return on Shr. Equity	*14.5%*
11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	13.4%	12.9%	*13.0%*	*13.0%*	Return on Com Equity	*14.5%*
4.9%	3.7%	3.2%	2.8%	2.7%	3.7%	4.6%	4.3%	6.7%	6.1%	*5.5%*	*5.5%*	Retained to Com Eq	*6.0%*
56%	63%	67%	70%	72%	65%	60%	61%	50%	53%	*57%*	*53%*	All Div'ds to Net Prof	*59%*

CURRENT POSITION ($MILL.)

	2012	2013	12/31/14
Cash Assets	5.5	5.1	4.1
Receivables	92.9	95.4	97.0
Inventory (AvgCst)	11.8	11.4	12.8
Other	150.7	59.8	38.6
Current Assets	260.9	171.7	152.5
Accts Payable	55.5	65.8	60.0
Debt Due	125.4	123.0	70.0
Other	93.3	78.1	95.3
Current Liab.	274.2	266.9	225.3
Fix. Chg. Cov.	413%	388%	389%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	6.5%	4.0%	4.5%
"Cash Flow"	8.0%	8.0%	9.5%
Earnings	8.5%	11.0%	8.0%
Dividends	7.5%	7.0%	9.0%
Book Value	8.0%	6.0%	5.5%

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2102	164.0	191.7	214.6	187.5	757.8
2013	180.0	195.7	204.3	188.6	768.6
2014	182.7	195.3	210.5	191.4	779.9
2015	*185*	*200*	*215*	*200*	*800*
2016	*190*	*205*	*220*	*210*	*825*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.15	.24	.29	.19	.87
2013	.26	.30	.36	.24	1.16
2014	.24	.31	.38	.28	1.20
2015	*.25*	*.32*	*.39*	*.29*	*1.25*
2016	*.26*	*.33*	*.41*	*.30*	*1.30*

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.124	.124	.124	.132	.50
2012	.132	.132	.132	.14	.54
2013	.14	.14	.152	.152	.58
2014	.152	.152	.165	.165	.63
2015	.165				

BUSINESS: Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately three million residents in Pennsylvania, Ohio, North Carolina, Illinois, Texas, New Jersey, Florida, Indiana, and five other states. Has 1,617 employees. Acquired AquaSource, 7/03; Consumers Water, 4/99; and others. Water supply revenues '14: residential, 68%; commercial, 17%; industrial & other, 15%. Officers and directors own .8% of the common stock; Vangurad Group, 6.6%; State Street Capital Corp., 6.3%; Blackrock, Inc, 6.1% (4/14 Proxy). Chairman & Chief Executive Officer: Nicholas DeBenedictis. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Telephone: 610-525-1400. Internet: www.aquaamerica.com.

Aqua America has healthy long-term dividend growth prospects. Based upon our projections of the company's ability to internally generate cash, we estimate that the annual payout may increase roughly 9% per annum through 2018-2020. This is a much higher rate than that of the typical stock in the industry.

Earnings gains will probably moderate both this year and next. Excluding the $0.11-a-share gain from the sale of its operations in Fort Wayne, Aqua's share net rose 3.4% in 2014. Considering that 2013 was an exceptional year, the comparison was actually good. Due to some rate relief, synergies from acquisitions, and the ability to earn returns on capital investments with little regulatory lag, we expect the utility to record 4% bottom-line increases in both 2015 and 2016.

Expansion via acquisitions is a major part of the company's strategy. Most water systems in the U.S. are small and municipally owned. Over the past two decades, Aqua has made over 300 purchases, including 16 in 2014. As these smaller water districts realize that they do not have the finances to modernize their aging infrastructures, they will continue to look toward merging with larger companies. With a significant amount of redundancies, cost savings from synergies can be significant in this industry

Low energy prices could impact nonregulated operations. Hydraulic fracking has become a major presence in Aqua's service areas. With each well requiring five million gallons of water, transporting it by truck is both burdensome and expensive. Extending pipeline systems directly to the wells can be very profitable for water utilities. Revenues from this sector should decline, however, as drillers shut wells until the energy market recovers.

Investors willing to sacrifice some returns for more certainty may like these shares. On the plus side, Aqua America stock has a decent well-protected dividend yield, favorable payout growth prospects, a solid balance sheet, the highest (95) mark for Stock Price Stability, well-defined earnings, and a 2 (Above Average) Safety rank. All told, we believe that the potential total returns are adequate on a risk-adjusted basis.

James A. Flood *April 17, 2015*

(A) Diluted egs. Excl. nonrec. gains (losses): '99, (9¢); '00, 2¢; '01, 2¢; '02, 4¢; '03, 3¢; '12, 18¢. Excl. gain from disc. operations: '12, 7¢; '13, 9¢; '14, 11¢. May not sum due to rounding.
Next earnings report due mid-May.
(B) Dividends historically paid in early March, June, Sept. & Dec. ■ Div'd. reinvestment plan available (5% discount).
(C) In millions, adjusted for stock splits.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	95

CALIFORNIA WATER NYSE-CWT

RECENT PRICE **24.76** | P/E RATIO **19.2** (Trailing: 23.1 / Median: 20.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS **3** Raised 6/20/14
SAFETY **3** Lowered 7/27/07
TECHNICAL **2** Raised 4/3/15
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	19.0	21.1	22.9	22.7	23.3	24.1	19.8	19.4	19.3	23.4	26.4	26.0
Low:	13.0	15.6	16.4	17.1	13.8	16.7	16.9	16.7	16.8	18.4	20.3	23.6

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

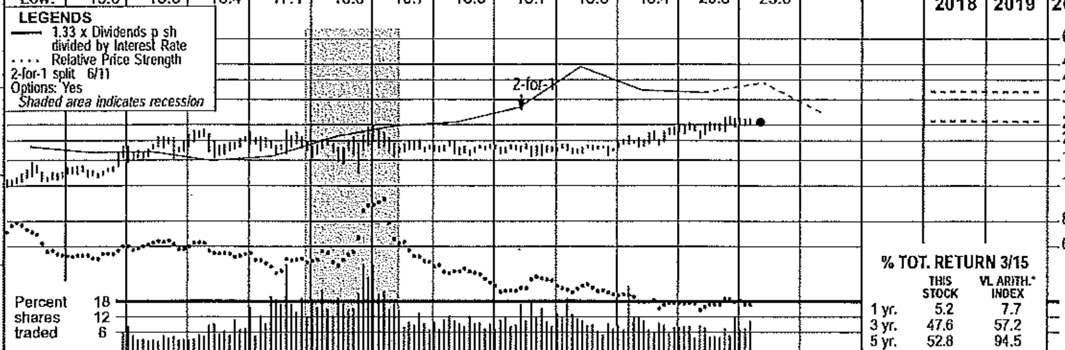
	Price	Gain	Ann'l Total Return
High	35	(+40%)	11%
Low	25	(Nil)	3%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	0	0	0	0	0
to Sell	1	0	0	0	0	0	3	2	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	57	53	81
to Sell	56	53	59
Hld's(000)	30279	29552	29654



% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.2	7.7
3 yr.	47.6	57.2
5 yr.	52.8	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
7.98	8.08	8.13	8.67	8.18	8.59	8.72	8.10	8.88	9.90	10.82	11.05	12.00	13.34	12.23	12.50	12.80	13.25	Revenues per sh	16.80
1.37	1.26	1.10	1.32	1.26	1.42	1.52	1.36	1.56	1.86	1.93	1.93	2.07	2.32	2.21	2.50	2.60	2.65	"Cash Flow" per sh	3.20
.77	.66	.47	.63	.61	.73	.74	.67	.75	.95	.98	.91	.86	1.02	1.02	1.19	1.20	1.20	Earnings per sh A	1.55
.54	.55	.56	.56	.56	.57	.57	.58	.58	.59	.59	.60	.62	.63	.64	.65	.67	.69	Div'd Decl'd per sh B ■	.97
1.72	1.23	2.04	2.91	2.19	1.87	2.01	2.14	1.84	2.41	2.66	2.97	2.83	3.04	2.58	2.75	2.50	2.60	Cap'l Spending per sh	3.10
6.71	6.45	6.48	6.56	7.22	7.83	7.90	9.07	9.25	9.72	10.13	10.45	10.76	11.28	12.54	13.22	13.75	14.25	Book Value per sh C	16.00
25.87	30.29	30.36	30.36	33.86	36.73	36.78	41.31	41.33	41.45	41.53	41.67	41.82	41.98	47.74	47.81	48.00	48.00	Common Shs Outst'g D	50.00
17.8	19.6	27.1	19.8	22.1	20.1	24.9	29.2	26.1	19.8	19.7	20.3	21.3	17.9	20.1	19.3	Bold figures are	Value Line	Avg Ann'l P/E Ratio	20.0
1.01	1.27	1.39	1.08	1.26	1.06	1.33	1.58	1.39	1.19	1.31	1.29	1.34	1.14	1.13	1.02	estimates		Relative P/E Ratio	1.25
4.0%	4.3%	4.4%	4.5%	4.2%	3.9%	3.1%	2.9%	3.0%	3.1%	3.1%	3.2%	3.4%	3.5%	3.1%	2.8%			Avg Ann'l Div'd Yield	3.2%

CAPITAL STRUCTURE as of 12/31/14
Total Debt $504.9 mill. Due in 5 Yrs $206.7 mill.
LT Debt $419.2 mill. LT Interest $20.0 mill.
(LT interest earned: 4.2x; total int. cov.: 4.0x) (40% of Cap'l)

Pension Assets-12/14 $306.3 mill. Oblig. $390.6 mill.

Pfd Stock None

Common Stock 47,800,997 shs. as of 2/9/15

MARKET CAP: $1.2 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
320.7	334.7	367.1	410.3	449.4	460.4	501.8	560.0	584.1	597.5	615	635	Revenues ($mill) E	840
27.2	25.6	31.2	39.8	40.6	37.7	36.1	42.6	47.3	56.7	57.5	57.5	Net Profit ($mill)	77.5
42.4%	37.4%	39.9%	37.7%	40.3%	39.5%	40.5%	37.5%	30.3%	33.0%	28.5%	29.5%	Income Tax Rate	36.0%
3.3%	10.6%	8.3%	8.6%	7.6%	4.2%	7.6%	8.0%	4.3%	2.7%	2.0%	4.5%	AFUDC % to Net Profit	5.0%
48.3%	43.5%	42.9%	41.6%	47.1%	52.4%	51.7%	47.8%	41.6%	40.1%	43.0%	43.5%	Long-Term Debt Ratio	41.5%
51.1%	55.9%	56.6%	58.4%	52.9%	47.6%	48.3%	52.2%	58.4%	59.9%	57.0%	56.5%	Common Equity Ratio	58.5%
568.1	670.1	674.9	690.4	794.9	914.7	931.5	908.2	1024.9	1045.9	1160	1215	Total Capital ($mill)	1370
862.7	941.5	1010.2	1112.4	1198.1	1294.3	1381.1	1457.1	1515.8	1590.4	1660	1730	Net Plant ($mill)	1820
6.3%	5.2%	5.9%	7.1%	6.5%	5.5%	5.5%	6.3%	6.0%	6.8%	6.5%	6.0%	Return on Total Cap'l	7.0%
9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	9.0%	7.9%	9.0%	9.0%	8.5%	Return on Shr. Equity	9.5%
9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	9.0%	7.9%	9.0%	9.0%	8.5%	Return on Com Equity	9.5%
2.1%	1.0%	1.8%	3.8%	3.8%	3.0%	2.3%	3.4%	3.4%	4.1%	4.0%	3.5%	Retained to Com Eq	3.5%
78%	86%	77%	61%	60%	66%	71%	62%	56%	55%	56%	58%	All Div'ds to Net Prof	63%

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	38.8	27.5	19.6
Other	107.8	112.0	134.5
Current Assets	146.6	139.5	154.1
Accts Payable	46.8	55.1	59.4
Debt Due	136.3	54.7	85.7
Other	59.7	56.8	72.6
Current Liab.	242.8	166.6	217.7
Fix. Chg. Cov.	296%	301%	299%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	4.0%	7.0%	5.0%
"Cash Flow"	6.0%	6.5%	5.5%
Earnings	5.5%	4.0%	7.5%
Dividends	1.0%	1.5%	7.0%
Book Value	5.5%	4.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	116.8	143.6	178.1	121.5	560.0
2013	111.4	154.6	184.4	133.7	584.1
2014	110.5	158.4	191.2	137.4	597.5
2015	115	165	195	140	615
2016	120	170	200	145	635

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.03	.31	.56	.12	1.02
2013	.01	.28	.61	.12	1.02
2014	d.11	.36	.70	.24	1.19
2015	Nil	.32	.73	.15	1.20
2016	Nil	.31	.74	.15	1.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.154	.154	.154	.154	.62
2012	.1575	.1575	.1575	.1575	.63
2013	.16	.16	.16	.16	.64
2014	.1625	.1625	.1625	.1625	.65
2015	.1675				

BUSINESS: California Water Service Group provides regulated and nonregulated water service to 477,900 customers in 85 communities in the state of California. Accounts for over 94% of total customers. Also operates in Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '14: residential, 68%; business, 19%; industrial, 5%; public authorities, 3%; other 5%. '14 reported depreciation rate: 4.0%. Has 1,105 employees. President, Chairman, and CEO: Peter C. Nelson. Inc.: DE. Address: 1720 North First St., San Jose, CA 95112-4598. Tel.: 408-367-8200. Internet: www.calwatergroup.com.

State regulators (CPUC) have been working well with California Water Services during the region's historic drought. The more water it sells, the more revenues a water utility generates. Due to the ongoing lack of rainfall, the CPUC has implemented "decoupling." This mechanism encourages conservation, without having a major impact on a water utility's profits.

The company had a much better-than-expected fourth quarter. Fueled by rate relief implemented last year and reduced expenses, California Water's earnings per share doubled to $0.24, on a year-over-year basis in the December interim. This resulted in a hefty 17% bottom-line gain in 2014.

We expect profits to be flattish over the next two years. The bulk of the earnings gains resulting from higher rates were reflected in California Water's earnings in 2014. Based on state regulations, California water utilities can only file for adjustments for increased expenses once every three years. With most of the recent cost reductions probably not sustainable, we estimate that the company's share earnings will barely budge from last year's tally of $1.19, and come in at $1.20 for both 2015 and 2016.

The latest dividend hike was a bit of a disappointment. We had been looking for a 4.6% increase in the quarterly payout to $0.17 a share, instead it was only raised by 3.1% to $0.1675.

California Water's finances are in fine shape. The equity-to-total capital ratio was at an industry high of 60% at year-end 2014. Much of this can be attributed to a large equity offering in 2013. Capital expenditures to replace an aging pipleine infrastructure will probably increase in the years ahead. Because of the strong balance sheet, we don't anticipate any major equity offerings out to the late decade. Additional debt may be required, but we believe the utility's financial metrics will remain above the industry averages.

These shares are not of particular interest at this juncture. On the plus side, CWT's yield is higher than most of the stocks in the water industry. Over the pull to 2018-2020, however, the stock has below-average total return potential.

James A. Flood *April 17, 2015*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (4¢); '01, 2¢; '02, 4¢; '11, 4¢. Next earnings report due mid-May. (B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. intangible assets. In '14 : $7.3 mill., $0.15/sh.
(D) In millions, adjusted for splits.
(E) Excludes non-reg. rev.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	90

CONNECTICUT WATER NDQ-CTWS

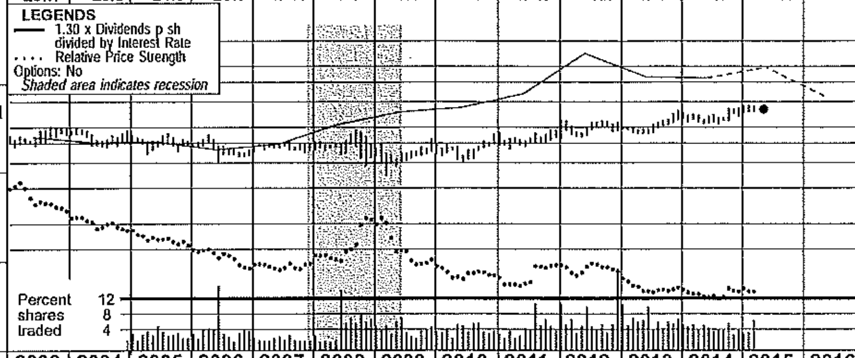
RECENT PRICE 36.82 | P/E RATIO 18.7 (Trailing: 19.2 / Median: 22.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 11/21/14
SAFETY 3 New 1/18/13
TECHNICAL 2 Raised 3/27/15
BETA .65 (1.00 = Market)

High:	29.8	28.2	27.7	25.6	29.0	26.4	27.9	29.1	32.8	36.4	37.5	38.6		
Low:	23.8	21.9	20.3	22.4	19.3	17.3	20.0	23.3	26.2	27.8	31.0	35.1		

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+35%)	10%
Low	35	(-5%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	40	50	36
to Sell	32	34	46
Hld's(000)	4304	4299	4296

Percent shares traded 12 8 4

% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.5	7.7
3 yr.	40.9	57.2
5 yr.	84.5	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
5.87	5.70	5.93	5.77	5.91	6.04	5.81	5.68	7.05	7.24	6.93	7.65	7.93	9.47	8.29	8.45	8.75	9.00	Revenues per sh	12.50
1.65	1.73	1.78	1.78	1.89	1.91	1.62	1.52	1.90	1.95	1.93	2.04	2.11	2.64	2.63	3.00	3.20	3.35	"Cash Flow" per sh	3.60
1.03	1.09	1.13	1.12	1.15	1.16	.88	.81	1.05	1.11	1.19	1.13	1.13	1.53	1.66	1.92	2.00	2.10	Earnings per sh A	2.25
.79	.79	.80	.81	.83	.84	.85	.86	.87	.88	.90	.92	.94	.96	.98	1.01	1.05	1.09	Div'd Decl'd per sh B■	1.30
1.42	1.43	1.86	1.98	1.49	1.58	1.96	1.96	2.24	2.44	3.28	3.06	2.61	2.79	3.02	4.11	4.60	4.15	Cap'l Spending per sh	2.85
8.61	8.92	9.25	10.06	10.46	10.94	11.52	11.60	11.95	12.23	12.67	13.05	13.50	20.95	17.92	18.84	20.10	21.15	Book Value per sh D	24.15
7.26	7.28	7.65	7.94	7.97	8.04	8.17	8.27	8.38	8.46	8.57	8.68	8.76	8.85	11.04	11.12	11.20	11.35	Common Shs Outst'g C	12.00
18.2	18.2	21.5	24.3	23.5	22.9	28.6	29.0	23.0	22.2	18.4	20.7	23.0	19.4	18.4	17.7	Bold figures are	Value Line	Avg Ann'l P/E Ratio	19.0
1.04	1.18	1.10	1.33	1.34	1.21	1.52	1.57	1.22	1.34	1.23	1.32	1.44	1.23	1.03	.93	estimates		Relative P/E Ratio	1.20
4.2%	4.0%	3.3%	3.0%	3.0%	3.1%	3.4%	3.6%	3.6%	3.6%	4.1%	3.9%	3.6%	3.2%	3.2%	3.0%			Avg Ann'l Div'd Yield	2.8%

CAPITAL STRUCTURE as of 12/31/14
Total Debt $181.0 mill. Due in 5 Yrs $19.3 mill.
LT Debt $176.6 mill. LT Interest $7.0 mill.
(Total interest coverage: 4.4x)
(46% of Cap'l)
Leases, Uncapitalized: Annual rentals $.1 mill.
Pension Assets-12/14 $61.6 mill.
Oblig. $79.8 mill.

Pfd Stock $0.8 mill. Pfd Divd NMF

Common Stock 11,152,627 shs.
as of 3/1/15
MARKET CAP: $400 million (Small Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
47.5	46.9	59.0	61.3	59.4	66.4	69.4	83.8	91.5	94.0	98.0	102	Revenues ($mill)	150
7.2	6.7	8.8	9.4	10.2	9.8	9.9	13.6	18.3	21.3	23.0	24.0	Net Profit ($mill)	27.0
--	23.5%	32.4%	27.2%	19.5%	35.2%	41.3%	32.0%	28.0%	14.5%	18.0%	19.5%	Income Tax Rate	30.0%
--	--	--	1.7%	--	--	--	1.7%	2.0%	2.4%	2.5%	2.5%	AFUDC % to Net Profit	2.0%
44.9%	44.4%	47.8%	46.9%	50.6%	49.5%	53.2%	49.0%	46.9%	45.7%	45.5%	47.5%	Long-Term Debt Ratio	47.5%
54.6%	55.1%	51.8%	52.7%	49.1%	50.2%	46.5%	50.8%	52.9%	54.2%	54.5%	52.5%	Common Equity Ratio	52.5%
172.3	174.1	193.2	198.5	221.3	225.6	254.2	364.6	373.6	386.8	420	455	Total Capital ($mill)	550
247.7	268.1	284.3	302.3	325.2	344.2	362.4	447.9	471.9	506.9	535	560	Net Plant ($mill)	675
5.0%	4.9%	5.5%	5.9%	5.5%	5.4%	4.9%	4.8%	5.9%	6.4%	6.5%	6.5%	Return on Total Cap'l	6.0%
7.5%	6.9%	8.7%	9.0%	9.3%	8.6%	8.3%	7.3%	9.2%	10.2%	10.0%	10.0%	Return on Shr. Equity	9.5%
7.6%	7.0%	8.7%	9.1%	9.4%	8.7%	8.3%	7.3%	9.2%	10.2%	10.0%	10.0%	Return on Com Equity	9.5%
.3%	NMF	1.6%	1.9%	2.3%	1.6%	1.4%	2.8%	3.8%	4.5%	4.5%	4.5%	Retained to Com Eq	4.0%
95%	105%	82%	79%	76%	81%	83%	62%	59%	53%	53%	52%	All Div'ds to Net Prof	58%

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	13.2	18.4	2.5
Accounts Receivable	11.5	12.3	12.0
Other	11.7	16.2	21.7
Current Assets	36.4	46.9	36.2
Accts Payable	10.0	10.8	10.0
Debt Due	3.0	4.1	4.4
Other	2.9	7.8	9.2
Current Liab.	15.9	22.7	23.6
Fix. Chg. Cov.	408%	375%	375%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	4.0%	5.0%	5.5%
"Cash Flow"	3.0%	6.5%	5.5%
Earnings	2.5%	8.0%	6.5%
Dividends	1.5%	2.0%	4.5%
Book Value	6.0%	8.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	18.5	21.3	24.5	19.5	83.8
2013	19.7	22.6	27.6	21.6	91.5
2014	20.3	25.4	27.6	20.7	94.0
2015	21.5	26.5	29.0	21.0	98.0
2016	22.5	27.5	30.0	22.0	102.0

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.22	.47	.67	.16	1.53
2013	.24	.39	.86	.17	1.66
2014	.27	.67	.76	.22	1.92
2015	.35	.60	.80	.25	2.00
2016	.36	.62	.85	.27	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.233	.233	.238	.238	.942
2012	.238	.238	.2425	.2425	.962
2013	.2425	.2425	.2475	.2475	.98
2014	.2475	.2475	.2575	.2575	1.01
2015	.2575				

BUSINESS: Connecticut Water Service, Inc. is a non-operating holding company, whose income is derived from earnings of its wholly-owned subsidiary companies (regulated water utilities). In 2014, 93% of net income was derived from these activities. Provides water services to 400,000 people in 77 municipalities throughout Connecticut and Maine. Acquired The Maine Water Company, January, 2012; Biddeford and Saco Water, December, 2012. Incorporated: Connecticut. Has 265 employees. Chairman/President/Chief Executive Officer: Eric W. Thornburg. Officers and directors own 2.3% of the common stock; BlackRock, Inc. 7.0%; (4/15 proxy). Address: 93 West Main Street, Clinton, CT 06413. Telephone: (860) 669-8636. Internet: www.ctwater.com.

Connecticut Water Services will be hard-pressed to repeat last year's impressive performance. Share net rose 16% in 2014, thanks mostly to an agreement with regulators regarding a rebate from the IRS. Still, we estimate that the utility can string together two consecutive solid years in 2015 and 2016. Margins are improving as the company is successfully integrating two acquisitions made in 2012. Moreover, the Biddleford and Saco operation in Maine was recently granted a significant rate increase. As a result, we think Connecticut Water can still grow earnings 4%-5% per annum over the next two years.

Capital expenditures are scheduled to be large in the short term. In addition, to having to replace older pipes (like almost every other water utility), the company has agreed to supply water to two new customers. Funds are being spent to extend the infrastructure in Connecticut to service the town of Mansfield and the University of Connecticut's Storrs campus, which is the size of a small city. Overall, we expect the capital budget to average over $50 million a year through 2016, which represents a 10% increase over the relatively large outlays made in 2014. Starting in 2017, however, construction should take a breather.

The balance sheet is strong enough to handle the increased spending. The equity-to-total capital ratio will most likely decline from its very healthy level of 54.5% to 52.5% by year-end 2016. Despite the dip, this percentage is high for a water utility.

Dividend growth prospects have improved. Over the past five- and 10-year periods, the company has only raised its annual payout by 1.5% and 2.0%, respectively. This rate lagged the industry mean by a wide margin. We expect this gap to narrow substantially in the long term. Indeed, dividend hikes through late decade will probably average 4.5%.

Shares of Connecticut Water do not hold much appeal at their recent price. Despite having a high yield, the stock is expected to only perform in line with the market averages in the year ahead. Potential returns through late decade are even less attractive.

James A. Flood *April 17, 2015*

(A) Diluted earnings. Next earnings report due mid-May. Quarterly earnings do not add in 2012 due to rounding.
(B) Dividends historically paid in mid-March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for split.
(D) Includes intangibles. In 2014: $31.7 million/$2.85 a share.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	85

CONSOL. WATER CO. NDQ-CWCO

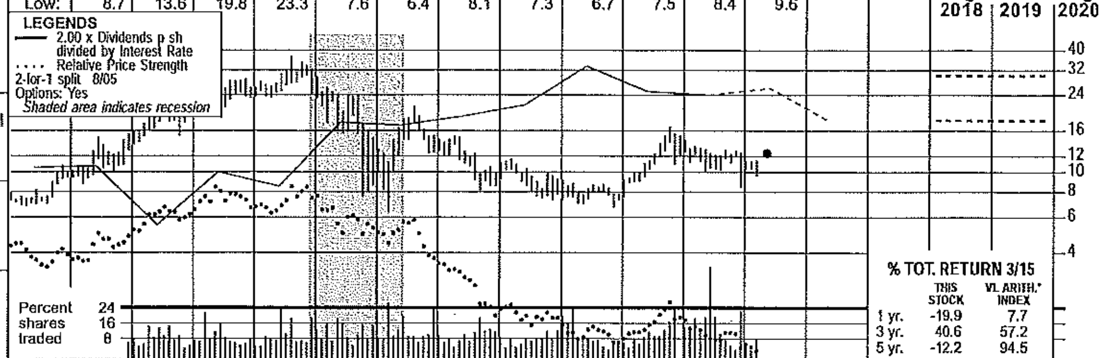
RECENT PRICE 12.43 | P/E RATIO 20.7 (Trailing: 29.6 Median: 27.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 4 Lowered 3/27/15
SAFETY 3 New 1/17/14
TECHNICAL 3 Raised 4/3/15
BETA .90 (1.00 = Market)

High:	15.5	22.5	31.8	37.5	29.8	21.3	15.1	11.7	9.2	16.9	14.5	12.7
Low:	8.7	13.6	19.8	23.3	7.6	6.4	8.1	7.3	6.7	7.5	8.4	9.6

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 2.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 8/05
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+140%)	27%
Low	18	(+45%)	11%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	1	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	35	32	28
to Sell	54	31	28
Hld's(000)	6207	6127	5703

Percent shares traded 24 16 8

% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-19.9	7.7
3 yr.	40.6	57.2
5 yr.	-12.2	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
1.25	1.24	1.41	1.52	1.68	2.02	1.12	2.71	3.41	4.52	3.99	3.49	3.79	4.49	4.35	4.46	*4.75*	*5.00*	Revenues per sh	*5.95*
.43	.46	.52	.50	.63	.77	.37	.87	1.20	.95	1.18	.86	.83	1.17	.96	.80	*1.05*	*1.10*	"Cash Flow" per sh	*1.60*
.31	.34	.35	.32	.42	.49	.23	.59	.79	.50	.74	.43	.42	.64	.58	.42	*.60*	*.65*	Earnings per sh A	*1.10*
.08	.17	.20	.21	.21	.23	.12	.24	.20	.33	.28	.30	.30	.30	.30	.30	*.30*	*.30*	Div'd Decl'd per sh B■	*.40*
.24	.30	.24	.39	.19	.24	.77	1.83	.54	.46	.18	.09	.96	.31	.29	.32	*.60*	*.60*	Cap'l Spending per sh	*.60*
1.96	2.30	2.45	2.64	3.89	4.20	2.54	7.49	8.21	8.36	8.53	8.69	8.83	9.20	9.44	9.59	*9.85*	*10.20*	Book Value per sh	*13.65*
6.38	7.73	7.84	7.99	11.37	11.51	23.46	14.13	14.40	14.53	14.54	14.55	14.57	14.59	14.69	14.72	*14.75*	*15.00*	Common Shs Outst'g C	*16.00*
11.7	10.4	13.9	21.6	19.3	23.1	NMF	43.0	35.4	37.8	19.0	26.9	22.4	12.4	20.0	27.4	*Bold figures are*		Avg Ann'l P/E Ratio	*21.0*
.67	.68	.71	1.18	1.10	1.22	NMF	2.32	1.88	2.27	1.27	1.71	1.41	.79	1.12	1.44	*Value Line*		Relative P/E Ratio	*1.30*
2.2%	4.9%	4.2%	3.1%	2.6%	2.0%	.7%	.9%	.7%	1.7%	2.0%	2.6%	3.2%	3.8%	2.6%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*1.6%*
						26.2	38.2	49.2	65.7	58.0	50.7	55.2	65.5	63.8	65.6	*70.0*	*75.0*	Revenues ($mill)	*95.0*
						5.5	7.5	11.4	7.2	10.8	6.3	6.1	9.3	8.6	6.3	*9.0*	*10.0*	Net Profit ($mill)	*17.5*
						--	--	--	--	--	--	--	--	--	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
						--	--	--	--	--	--	4.0%	--	--	--	*NMF*	*NMF*	AFUDC % to Net Profit	*NMF*
						24.5%	18.2%	15.9%	14.8%	13.8%	11.8%	5.1%	3.7%	3.7%	--	*Nil*	*Nil*	Long-Term Debt Ratio	*Nil*
						75.4%	81.8%	84.1%	85.2%	86.2%	88.2%	94.9%	96.3%	99.8%	100%	*100%*	*100%*	Common Equity Ratio	*100%*
						78.9	129.3	140.7	142.7	143.9	143.3	135.6	139.4	138.9	141.1	*145*	*153*	Total Capital ($mill)	*205*
						44.8	63.6	65.0	65.1	61.2	56.2	64.3	61.6	58.6	56.4	*60.0*	*65.0*	Net Plant ($mill)	*100.0*
						7.5%	6.5%	8.8%	5.7%	8.1%	4.9%	5.0%	7.0%	6.2%	4.5%	*6.0%*	*6.5%*	Return on Total Cap'l	*8.5%*
						9.3%	7.1%	9.6%	5.9%	8.7%	5.0%	4.7%	6.9%	6.2%	4.5%	*6.0%*	*6.5%*	Return on Shr. Equity	*8.5%*
						9.2%	7.1%	9.6%	5.9%	8.7%	5.0%	4.7%	6.9%	6.2%	4.5%	*6.0%*	*6.5%*	Return on Com Equity	*8.5%*
						4.6%	4.2%	6.5%	2.8%	4.6%	1.5%	1.0%	3.6%	3.0%	1.3%	*3.0%*	*3.5%*	Retained to Com Eq	*5.0%*
						50%	41%	33%	52%	46%	69%	79%	48%	51%	71%	*50%*	*46%*	All Div'ds to Net Prof	*36%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $9.0 mill. Due in 5 Yrs $9.0 mill.
LT Debt None LT Interest None

Leases, Uncapitalized: Annual rentals $.7 mill.

No Defined Benefit Pension Plan

Pfd Stock NMF 36,840 shares out. Div'd NMF

Common Stock 14,715,899 shs.
as of 3/9/14

MARKET CAP: $175 million (Small Cap)

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	42.5	42.2	40.7
Accts Receivable	14.3	18.9	11.8
Other	4.5	6.5	6.9
Current Assets	61.3	67.6	59.4
Accts Payable	5.9	7.2	6.0
Debt Due	1.6	5.2	9.0
Other	1.2	11.2	1.2
Current Liab.	8.7	23.6	16.2
Fix. Chg. Cov.	832%	NMF	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	10.5%	3.5%	5.0%
"Cash Flow"	6.0%	-0.5%	7.0%
Earnings	4.5%	-2.5%	10.5%
Dividends	4.0%	3.5%	4.0%
Book Value	12.0%	2.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	16.7	16.2	15.8	16.8	65.5
2013	16.6	16.6	15.4	15.2	63.8
2014	16.3	16.9	17.0	15.4	65.6
2015	*17.5*	*17.5*	*18.5*	*16.5*	*70.0*
2016	*18.5*	*18.5*	*19.5*	*18.5*	*75.0*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.17	.13	.09	.25	.64
2013	.26	.19	.06	.07	.58
2014	.04	.19	.13	.06	.42
2015	*.16*	*.22*	*.16*	*.06*	*.60*
2016	*.18*	*.24*	*.17*	*.06*	*.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.075	.075	.075	.075	.30
2012	.075	.075	.075	.075	.30
2013	.075	.075	.075	.075	.30
2014	.075	.075	.075	.075	.30
2015	.075				

BUSINESS: Consolidated Water Co. Ltd. develops and operates seawater desalination plants and water distribution systems in areas where naturally occurring supplies of potable water are scarce or nonexistent. Its desalination process involves reverse osmosis tech. It provides water in the Cayman Islands, Belize, the Bahamas, the British Virgin Islands, and Bali. At 12/31/14, it operated 14 plants with a capacity of 26.5 million gallons per day. Inc.: Cayman Islands. Has 119 employees. Pres./CEO: Frederick W. McTaggart. Off./dir. own 3.68% of stock; Investco Limited, 5.54% (4/14 proxy). Address: Regatta Office Park Windward Three, 4th Floor, West Bay Road P.O. Box 1114 Grand Cayman, KYI-1102, Cayman Islands. Tel.: (345) 945-4277. Internet: www.cwco.com.

Consolidated Water's investment in the British Virgin Islands (BVI) is having a negative impact on earnings. For almost a decade, the BVI government and the water company have been engaged in several legal disputes, with the most recent being centered on the OC-BVI desalination facility. As an equity investment, Consolidated must determine the market value of OC-BVI at the end of each year. Due to the ongoing conflicts with the BVI, the company had to write down the investment by about $0.06 in 2014. Moreover, the initial seven-year contract is due for renewal in 2017. Even though the BVI will most likely re-sign, Consolidated may be forced to take additional writedowns in 2015 and 2016. Consequently,

Our earnings estimates for this year and next are somewhat tentative. The retail water operations in the Caymans remain the bread and butter of the company's business. Prospects in this sector seem good, though the island's officials are making some noise about restructuring the deal. Profits from bulk water sales in the Bahamas are being hurt as conservation resulted in demand falling 17% last year. All told, we estimate that the company's share net will be $0.60 this year, and $0.65 in 2016.

Otherwise, Consolidated is involved in two very promising new ventures. Bali is one of the premier tourist destinations in the world, with many high-end hotels. Unfortunately, it has hardly any potable water. The company built a desalination plant that recently started operations and is in the process of ramping up. As the isle's population continues to grow, we expect this to be a very profitable long-term venture. In addition, plans to build a $600 million facility in Mexico (CWCO will own a 12% stake) that would provide water to two growing cities, San Diego and Tijuana, are going smoothly and construction may begin soon.

These shares are not timely. Moreover, the unresolved situation in the BVI adds uncertainty. Investors willing to live with a fair amount of risk may find this an interesting holding to 2018-2020, however, as CWCO could benefit greatly from the growing scarcity of water in its operating areas.

James A. Flood *April 17, 2015*

(A) Fully diluted earnings. Next earnings report due mid-May. Quarterly share earnings do not sum in 2014 due to rounding.
(B) Dividends historically paid in late January, April, July and October. ■ Dividend reinvestment plan available.
(C) In millions adjusted for stock split.

Company's Financial Strength	B+
Stock's Price Stability	35
Price Growth Persistence	10
Earnings Predictability	50

MIDDLESEX WATER NDQ-MSEX

RECENT PRICE 22.97 | P/E RATIO 19.6 (Trailing: 20.3 Median: 21.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 4/11/14
SAFETY 2 New 10/21/11
TECHNICAL 2 Raised 4/3/15
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	21.8	23.5	20.5	20.2	19.8	17.9	19.3	19.4	19.6	22.5	23.7	23.5
Low:	16.7	17.1	16.5	16.9	12.0	11.6	14.7	16.5	17.5	18.6	19.1	21.6

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

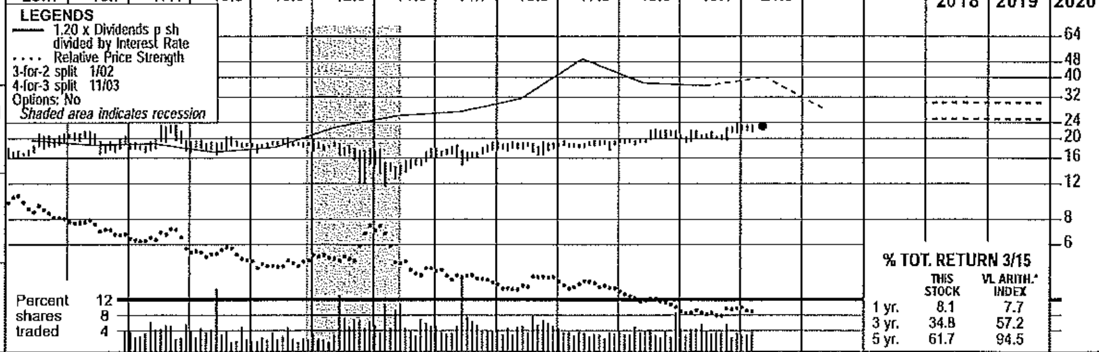
	Price	Gain	Ann'l Total Return
High	30	(+30%)	10%
Low	25	(+10%)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	2	0	0	0	1	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	1	0	0	0	1

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	41	32	39
to Sell	34	40	37
Hld's(000)	6463	6339	6372



% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.1	7.7
3 yr.	34.8	57.2
5 yr.	61.7	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
5.35	5.39	5.87	5.98	6.12	6.25	6.44	6.16	6.50	6.79	6.75	6.60	6.50	6.98	7.19	7.26	*7.40*	*7.70*	Revenues per sh	*9.10*
1.19	.99	1.18	1.20	1.15	1.28	1.33	1.33	1.49	1.53	1.40	1.55	1.46	1.56	1.72	*1.90*	*1.95*	*2.00*	"Cash Flow" per sh	*2.25*
.76	.51	.66	.73	.61	.73	.71	.82	.87	.89	.72	.96	.84	.90	1.03	1.13	*1.15*	*1.20*	Earnings per sh A	*1.35*
.60	.61	.62	.63	.65	.66	.67	.68	.69	.70	.71	.72	.73	.74	.75	.76	*.77*	*.78*	Div'd Decl'd per sh B■	*.85*
2.33	1.32	1.25	1.59	1.87	2.54	2.18	2.31	1.66	2.12	1.49	1.90	1.50	1.36	1.26	1.40	*1.80*	*2.00*	Cap'l Spending per sh	*2.00*
6.95	6.98	7.11	7.39	7.60	8.02	8.26	9.52	10.05	10.03	10.33	11.13	11.27	11.48	11.82	12.24	*12.75*	*13.25*	Book Value per sh	*14.30*
10.00	10.11	10.17	10.36	10.48	11.36	11.58	13.17	13.25	13.40	13.52	15.57	15.70	15.82	15.96	16.12	*16.25*	*16.25*	Common Shs Outst'g C	*17.00*
17.6	28.7	24.6	23.5	30.0	26.4	27.4	22.7	21.6	19.8	21.0	17.8	21.7	20.8	19.7	19.5	*Bold figures are*		Avg Ann'l P/E Ratio	*20.5*
1.00	1.87	1.26	1.28	1.71	1.39	1.46	1.23	1.15	1.19	1.40	1.13	1.36	1.32	1.11	1.01	*Value Line*		Relative P/E Ratio	*1.30*
4.4%	4.2%	3.8%	3.7%	3.5%	3.4%	3.5%	3.7%	3.7%	4.0%	4.7%	4.2%	4.0%	4.0%	3.7%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $160.9 mill. Due in 5 Yrs $49.8 mill.
LT Debt $136.0 mill. LT Interest $4.6 mill.
(LT interest earned: 6.0x)
(41% of Cap'l)

Pension Assets-12/14 $51.6 mill. Oblig. $75.0 mill.
Pfd Stock $2.4 mill. Pfd Div'd: $.2 mill.

Common Stock 16,129,050 shs. as of 2/28/15

MARKET CAP: $375 million (Small Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
74.6	81.1	86.1	91.0	91.2	102.7	102.1	110.4	114.8	117.1	*120*	*125*	Revenues ($mill)	*155*
8.5	10.0	11.8	12.2	10.0	14.3	13.4	14.4	16.6	18.4	*18.6*	*18.6*	Net Profit ($mill)	*23.0*
27.6%	33.4%	32.6%	33.2%	34.1%	32.1%	32.7%	33.9%	34.1%	*35.0%*	*34.5%*	*34.0%*	Income Tax Rate	*34.0%*
--	--	--	--	--	6.8%	6.1%	3.4%	1.9%	*1.0%*	*1.0%*	*1.5%*	AFUDC % to Net Profit	*2.5%*
55.3%	49.5%	49.0%	45.6%	46.6%	43.1%	42.3%	41.5%	40.4%	40.5%	*40.5%*	*42.0%*	Long-Term Debt Ratio	*43.5%*
41.3%	47.5%	49.6%	51.8%	52.1%	55.8%	56.6%	57.4%	58.7%	58.8%	*58.5%*	*57.5%*	Common Equity Ratio	*56.5%*
231.7	264.0	268.8	259.4	267.9	310.5	312.5	316.5	321.4	335.7	*350*	*375*	Total Capital ($mill)	*430*
288.0	317.1	333.9	366.3	376.5	405.9	422.2	435.2	446.5	465.4	*485*	*505*	Net Plant ($mill)	*550*
5.0%	5.1%	5.6%	5.8%	5.0%	5.7%	5.2%	5.4%	5.9%	*6.5%*	*6.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
8.2%	7.5%	8.6%	8.6%	7.0%	8.1%	7.5%	7.8%	8.7%	9.3%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
8.6%	7.8%	8.7%	8.9%	7.0%	8.2%	7.5%	7.8%	8.7%	9.3%	*9.0%*	*9.0%*	Return on Com Equity	*9.5%*
.6%	1.3%	1.8%	2.0%	.1%	2.1%	1.0%	1.4%	2.4%	3.0%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
94%	84%	79%	78%	98%	75%	87%	83%	73%	67%	*67%*	*65%*	All Div'ds to Net Prof	*63%*

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	3.0	4.8	2.7
Other	21.6	21.0	20.2
Current Assets	24.6	25.8	22.9
Accts Payable	3.8	6.3	6.4
Debt Due	11.1	33.8	24.9
Other	41.1	12.6	12.6
Current Liab.	56.0	52.7	43.9
Fix. Chg. Cov.	554%	697%	695%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	1.5%	1.0%	*6.5%*
"Cash Flow"	3.0%	1.5%	*5.5%*
Earnings	3.5%	1.5%	*5.0%*
Dividends	1.5%	1.5%	*2.0%*
Book Value	4.5%	3.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	23.5	27.4	32.4	27.1	110.4
2013	27.0	29.1	31.3	27.4	114.8
2014	27.1	29.2	32.7	28.1	117.1
2015	*28.0*	*30.0*	*33.0*	*29.0*	*120*
2016	*29.0*	*31.0*	*35.0*	*30.0*	*125*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.11	.23	.38	.17	.90
2013	.20	.28	.36	.19	1.03
2014	.20	.29	.42	.22	1.13
2015	*.21*	*.31*	*.43*	*.20*	*1.15*
2016	*.22*	*.32*	*.45*	*.21*	*1.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.183	.183	.183	.185	.73
2012	.185	.185	.185	.1875	.74
2013	.1875	.1875	.1875	.19	.75
2014	.19	.19	.19	.1925	.76
2015	.1925				

BUSINESS: Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey, Delaware, and Pennsylvania. It also operates water and wastewater systems under contract on behalf of municipal and private clients in NJ and DE. Its Middlesex System provides water services to 60,000 retail customers, primarily in Middlesex County, New Jersey. In 2014, the Middlesex System accounted for 60% of operating revenues. At 12/31/14, the company had 282 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers & directors own 3.5% of the common stock; BlackRock Institutional Trust Co., 6.6% (4/15 proxy). Add.: 1500 Ronson Road, Iselin, NJ 08830. Tel.: 732-634-1500. Internet: www.middlesexwater.com.

Middlesex Water had a surprisingly good 2014. For the second straight year, the company was able to post a double-digit gain in earnings per share. This was impressive considering that the utility is still in recovery mode following the 2013 loss of two major customers — a Hess refinery and the borough of Sayreville.

Bottom-line gains should moderate. The rate relief that was granted in New Jersey and Delaware will not have as positive an impact on profits as was the case last year. On the positive side, an agreement to distribnte water at the Dover Air Force Base (a major military installation) should provide a consistent source of revenues. Overall, we expect Middlesex's 2015 share net to barely rise, from $1.13 to $1.15 in 2015. Next year will probably be better, as we think per-share earnings can increase 4%, to $1.20.

We are not expecting Middlesex to change its remarkably consistent dividend policy through 2016. Since 2004, the utility has raised the payout by exactly $0.01 a share each and every year. With a dividend growth rate of 1.5% over both the past five- and 10-year periods, the company has lagged the industry mean by a substantial margin. When this tradition started, the dividend to net profits percentage was relatively high, meaning there was little room for increases. This figure fell to 57% in 2014, so Middlesex appears to have the flexibility to distribute a greater share of profits to shareholders.

The balance sheet may not be big, but it is strong. At the end of last year, Middlesex's equity-to-total capital ratio was close to 59%, the second highest in the industry. And, while this metric will most likely decline as debt is added to help fund the upgrading of the pipeline network, the utility's finances should remain very sound by late decade.

Middlesex stock has the highest yield of any member in the water industry. At 3.4%, the equity has a payout that is almost 80 basis points above the group average. Indeed, it is the only one that has a yield above 3%. Basically, investors are demanding a premium to own shares in this company. Despite the generous current income, the stock's potential returns through 2018-2020 are still subpar.

James A. Flood *April 17, 2015*

(A) Diluted earnings. May not sum due to rounding. Next earnings report due mid-May.
(B) Dividends historically peid in mid-Feb., May, Aug., and November.■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

SJW CORP. NYSE-SJW

RECENT PRICE 30.62 | P/E RATIO 24.3 (Trailing: 12.1 Median: 24.0) | RELATIVE P/E RATIO 1.26 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 4 Lowered 12/19/14
SAFETY 3 New 4/22/11
TECHNICAL 2 Raised 3/27/15
BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	19.6	27.8	45.3	43.0	35.1	30.4	28.2	26.8	26.9	30.1	33.7	35.7
Low:	14.6	16.1	21.2	27.7	20.0	18.2	21.6	20.9	22.6	24.5	25.5	29.8

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

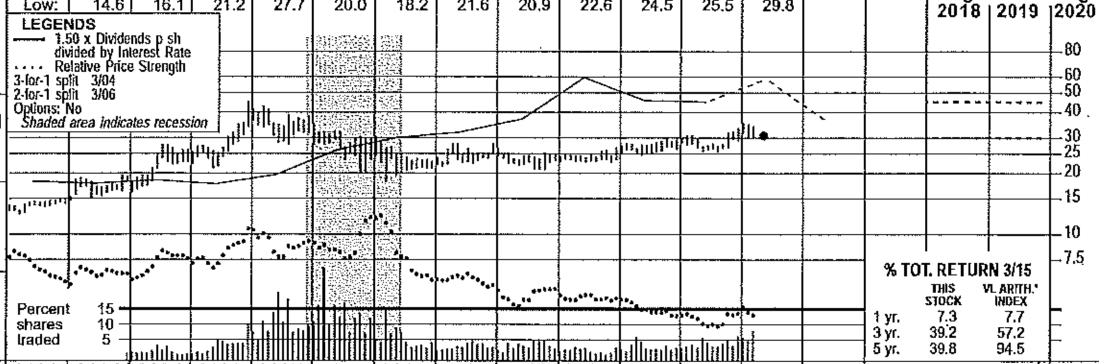
	Price	Gain	Ann'l Total Return
High	45	(+45%)	12%
Low	30	(Nil)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	1	1	0	1	1	0	0	1	0
Options	0	0	0	0	0	0	1	0	0
to Sell	0	0	0	0	1	0	1	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	45	38	49
to Sell	40	45	47
Hld's(000)	10965	10784	10867



1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
6.40	6.74	7.45	7.97	8.20	9.14	9.86	10.35	11.25	12.12	11.68	11.62	12.85	14.01	13.73	15.76	*14.15*	*14.05*	Revenues per sh	*17.60*
1.43	1.23	1.49	1.55	1.75	1.89	2.21	2.38	2.30	2.44	2.21	2.38	2.80	2.97	2.90	*4.50*	*3.45*	*3.55*	"Cash Flow" per sh	*3.90*
.87	.58	.77	.78	.91	.87	1.12	1.19	1.04	1.08	.81	.84	1.11	1.18	1.12	2.54	*1.35*	*1.40*	Earnings per sh A	*1.75*
.40	.41	.43	.46	.49	.51	.53	.57	.61	.65	.66	.68	.69	.71	.73	.75	*.78*	*.81*	Div'd Decl'd per sh B■	*1.05*
1.77	1.89	2.63	2.06	3.41	2.31	2.83	3.87	6.62	3.79	3.17	5.65	3.75	5.67	4.68	*5.00*	*5.00*	*4.95*	Cap'l Spending per sh	*4.90*
7.88	7.90	8.17	8.40	9.11	10.11	10.72	12.48	12.90	13.99	13.66	13.75	14.20	14.71	15.92	17.75	*18.30*	*19.05*	Book Value per sh	*21.30*
18.27	18.27	18.27	18.27	18.27	18.27	18.27	18.28	18.36	18.18	18.50	18.55	18.59	18.67	20.17	20.29	*20.50*	*21.00*	Common Shs Outst'g C	*23.00*
15.5	33.1	18.5	17.3	15.4	19.6	19.7	23.5	33.4	26.2	28.7	29.1	21.2	20.4	24.3	11.0	*Bold figures are*		Avg Ann'l P/E Ratio	*22.0*
.88	2.15	.95	.94	.88	1.04	1.05	1.27	1.77	1.58	1.91	1.85	1.33	1.30	1.37	.58	*Value Line*		Relative P/E Ratio	*1.40*
3.0%	2.1%	3.0%	3.4%	3.5%	3.0%	2.4%	2.0%	1.7%	2.3%	2.8%	2.8%	2.9%	3.0%	2.7%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
	180.1	189.2	206.6	220.3	216.1	215.6	239.0	261.5	276.9	319.7	*290*	*295*	Revenues ($mill)	*405*
	20.7	22.2	19.3	20.2	15.2	15.8	20.9	22.3	23.5	51.8	*27.5*	*29.0*	Net Profit ($mill)	*40.0*
	41.6%	40.8%	39.4%	39.5%	40.4%	38.8%	41.1%	41.1%	38.7%	*32.5%*	*37.0%*	*36.0%*	Income Tax Rate	*38.0%*
	1.6%	2.1%	2.7%	2.3%	2.0%	--	--	--	2.0%	*1.0%*	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.5%*
	42.6%	41.8%	47.7%	46.0%	49.4%	53.7%	56.6%	55.0%	51.1%	51.6%	*52.5%*	*52.5%*	Long-Term Debt Ratio	*53.5%*
	57.4%	58.2%	52.3%	54.0%	50.6%	46.3%	43.4%	45.0%	48.9%	48.4%	*47.5%*	*47.5%*	Common Equity Ratio	*46.5%*
	341.2	391.8	453.2	470.9	499.6	550.7	607.9	610.2	656.2	744.6	*790*	*845*	Total Capital ($mill)	*1025*
	484.8	541.7	645.5	684.2	718.5	785.5	756.2	831.6	898.7	963.0	*1010*	*1065*	Net Plant ($mill)	*1200*
	7.6%	7.0%	5.7%	5.8%	4.4%	4.3%	4.9%	5.0%	5.0%	8.3%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	7.3%	14.4%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	7.3%	14.4%	*7.5%*	*7.5%*	Return on Com Equity	*8.0%*
	5.6%	5.2%	3.5%	3.3%	1.2%	1.2%	3.1%	3.3%	2.8%	10.1%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
	47%	46%	57%	59%	80%	80%	61%	59%	62%	28%	*58%*	*58%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $398.2 mill. Due in 5 Yrs $21.2 mill.
LT Debt $384.4 mill. LT Interest $18.1 mill.
(Total interest coverage: 2.9x) (52% of Cap'l)

Leases, Uncapitalized: Annual rentals $5.5 mill.

Pension Assets-12/14 $91.4 mill. **Oblig.** $128.7 mill.

Pfd Stock None.

Common Stock 20,336,409 shs. as of 2/13/15

MARKET CAP: $625 million (Small Cap)

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	2.5	2.3	2.4
Other	40.4	37.4	65.7
Current Assets	42.9	39.7	68.1
Accts Payable	8.5	12.6	7.0
Debt Due	20.7	23.0	13.8
Other	19.9	23.6	23.9
Current Liab.	49.1	59.2	44.7
Fix. Chg. Cov.	317%	268%	270%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	5.5%	4.0%	*4.0%*
"Cash Flow"	6.0%	4.0%	*4.5%*
Earnings	3.5%	.5%	*6.5%*
Dividends	4.5%	3.5%	*5.5%*
Book Value	5.5%	2.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	51.1	65.6	82.4	62.4	261.5
2013	50.1	74.2	85.2	67.4	276.9
2014	54.6	70.4	125.4	69.3	319.7
2015	*56.0*	*73.0*	*89.0*	*72.0*	*290*
2016	*57.0*	*74.0*	*90.0*	*74.0*	*295*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.06	.28	.53	.31	1.18
2013	.07	.37	.44	.24	1.12
2014	.04	.34	1.88	.28	2.54
2015	*.05*	*.40*	*.53*	*.37*	*1.35*
2016	*.05*	*.40*	*.57*	*.38*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.173	.173	.173	.173	.69
2012	.1775	.1775	.1775	.1775	.71
2013	.1825	.1825	.1825	.1825	.73
2014	.1875	.1875	.1875	.1875	.75
2015	.1950				

BUSINESS: SJW Corporation engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 229,000 connections that serve a population of approximately one million people in the San Jose area and 12,000 connections that serve approximately 36,000 residents in a service area in the region between San Antonio and Austin, Texas. The company offers nonregulated water-related services. Also owns and operates commercial real estate investments. Has about 395 employees. Officers & directors (including Nancy O. Moss) own 27.9% of outstanding shares. Chrm.: Charles J. Toeniskoetter. Inc.: CA. Address: 110 W. Taylor Street, San Jose, CA 95110. Tel.: (408) 279-7800. Int: www.sjwater.com.

SJW's main operating service area is in the midst of an historic drought. The vast majority of the utility's revenues are derived from its water operations in the thriving San Jose area of California. The lack of rain and snow in the mountains has led to the state placing severe restrictions on water usage for conservation purposes. This should result in a steep decline in demand for water. To date, regulators have worked with water utilities using a mechanism know as "decoupling." Basically, this process doesn't meaningfully penalize utilities for encouraging residents to reduce consumption.

SJW's earnings have been skewed. In 2014, the company's profits more than doubled due to a one-time event. The utility received a large payment in the third quarter for past expenses that it was forced to absorb. Since the funds were received as compensation for normal business expenses, we did not classify it as a nonrecurring event.

SJW's bottom line should post decent gains over the next two years. We think that the company's share net can reach $1.35 in 2015. If 2014 had been a normal year, the year-over-year comparison would have been favorable. Next year's per-share earnings will probably only show a modest $0.05-a-share increase to $1.40, however. During 2015 and 2016, opposite forces will be at work pulling the utility's profits in different directions. On the positive side, SJW will be earning a return on the funds spent modernizing its pipeline infrastructure. Conversely, margins may be restrained by the scarcity of surface water, which would force SJW to pay more to either extract more ground water or purchase it from other sources.

The recent dividend increase was adequate. Though the 4% hike was positive in that it was higher than the company's historical growth rate, we thought that there was room for a 5% raise. This would have put the company's growth rate more in line with the industry norm.

These shares are ranked to underperform the broader market averages in the year ahead. Moreover, total return potential over the next three- to five-year period is subpar, as well.

James A. Flood *April 17, 2015*

(A) Diluted earnings. Excludes nonrecurring losses: '03, $1.97; '04, $3.78; '05, $1.09; '06, $16.36; '08, $1.22; '10, $0.46. Next earnings report due mid-May. Quarterly earnings may not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for stock splits.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	70

YORK WATER NDQ-YORW

RECENT PRICE 24.01 | P/E RATIO 24.5 (Trailing: 27.0, Median: 25.0) | RELATIVE P/E RATIO 1.27 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Raised 3/27/15
SAFETY 2 New 7/19/13
TECHNICAL 2 Lowered 4/17/15
BETA .70 (1.00 = Market)

High:	14.0	17.9	21.0	18.5	16.5	18.0	18.0	18.1	18.5	22.0	24.3	25.0
Low:	11.0	11.7	15.3	15.5	6.2	9.7	12.8	15.8	16.8	17.6	18.8	21.1

2018-20 PROJECTIONS

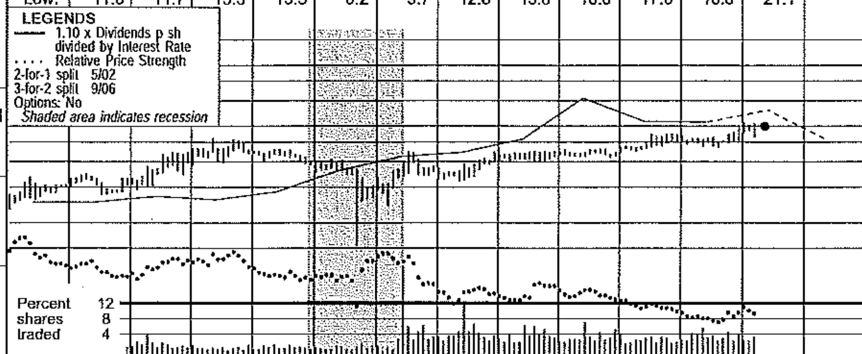
	Price	Gain	Ann'l Total Return
High	30	(+25%)	8%
Low	20	(-15%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	1	0	4	2	1	4	0	0	4
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	29	30	32
to Sell	28	30	24
Hld's(000)	3603	3656	3767



Target Price Range 2018 | 2019 | 2020

% TOT. RETURN 3/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.2	7.7
3 yr.	51.6	57.2
5 yr.	103.2	94.5

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	2.05	2.05	2.17	2.18	2.58	2.56	2.79	2.89	2.95	3.07	3.18	3.21	3.27	3.58	*3.85*	*4.00*	Revenues per sh	*4.75*
--	--	.59	.57	.65	.65	.79	.77	.86	.88	.95	1.07	1.09	1.12	1.19	*1.35*	*1.50*	*1.55*	"Cash Flow" per sh	*1.75*
--	--	.43	.40	.47	.49	.56	.58	.57	.57	.64	.71	.71	.72	.75	.89	*.95*	*1.00*	Earnings per sh A	*1.15*
--	--	.34	.35	.37	.39	.42	.45	.48	.49	.51	.52	.53	.54	.55	.57	*.60*	*.63*	Div'd Decl'd per sh B	*.79*
--	--	.75	.66	1.07	2.50	1.69	1.85	1.69	2.17	1.18	.83	.74	.94	.76	1.10	*1.10*	*1.20*	Cap'l Spending per sh	*1.15*
--	--	3.79	3.90	4.06	4.65	4.85	5.84	5.97	6.14	6.92	7.19	7.45	7.73	7.98	8.15	*8.15*	*8.65*	Book Value per sh	*9.60*
--	--	9.46	9.55	9.63	10.33	10.40	11.20	11.27	11.37	12.56	12.69	12.79	12.92	12.98	12.83	*12.50*	*12.50*	Common Shs Outst'g C	*12.00*
--	--	17.8	26.9	24.5	25.7	26.3	31.2	30.3	24.6	21.9	20.7	23.9	24.4	26.3	23.6	*Bold figures are*		Avg Ann'l P/E Ratio	*22.5*
--	--	.91	1.47	1.40	1.36	1.40	1.68	1.61	1.48	1.46	1.32	1.50	1.55	1.48	1.24	*Value Line*		Relative P/E Ratio	*1.40*
--	--	4.4%	3.3%	3.2%	3.1%	2.9%	2.5%	2.8%	3.5%	3.6%	3.5%	3.1%	3.1%	2.8%	2.5%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $84.8 mill. Due in 5 Yrs $30.5 mill.
LT Debt $84.8 mill. LT Interest $5.1 mill.
(Total interest coverage: 4.0x)
(45% of Cap'l)

Pension Assets 12/14 $30.6 mill.
Oblig. $40.9 mill.

Pfd Stock None

Common Stock 12,837,661 shs.
as of 3/9/14

MARKET CAP: $300 million (Small Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
26.8	28.7	31.4	32.8	37.0	39.0	40.6	41.4	42.4	45.9	*48.0*	*50.0*	Revenues ($mill)	*57.0*
5.8	6.1	6.4	6.4	7.5	8.9	9.1	9.3	9.7	11.5	*12.0*	*12.5*	Net Profit ($mill)	*14.0*
36.7%	34.4%	36.5%	36.1%	37.9%	38.5%	35.3%	37.6%	37.6%	29.8%	*29.5%*	*29.5%*	Income Tax Rate	*36.5%*
--	7.2%	3.6%	10.1%	--	1.2%	1.1%	1.1%	.8%	1.3%	*1.5%*	*1.5%*	AFUDC % to Net Profit	*1.0%*
44.1%	48.3%	46.5%	54.5%	45.7%	48.3%	47.1%	46.0%	45.1%	44.8%	*47.5%*	*47.0%*	Long-Term Debt Ratio	*48.0%*
55.9%	51.7%	53.5%	45.5%	54.3%	51.7%	52.9%	54.0%	54.9%	55.2%	*52.5%*	*53.0%*	Common Equity Ratio	*52.0%*
90.3	126.5	125.7	153.4	160.1	176.4	180.2	184.8	188.4	189.4	*195*	*205*	Total Capital ($mill)	*220*
155.3	174.4	191.6	211.4	222.0	228.4	233.0	240.3	244.2	253.2	*260*	*265*	Net Plant ($mill)	*280*
8.4%	6.2%	6.7%	5.7%	6.2%	6.5%	6.4%	6.4%	6.5%	*7.4%*	*7.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
11.6%	9.3%	9.5%	9.2%	8.6%	9.8%	9.5%	9.3%	9.3%	11.0%	*11.5%*	*11.5%*	Return on Shr. Equity	*12.0%*
11.6%	9.3%	9.5%	9.2%	8.6%	9.8%	9.5%	9.3%	9.3%	11.0%	*11.5%*	*11.5%*	Return on Com Equity	*12.0%*
3.0%	2.2%	1.7%	1.4%	1.9%	2.7%	2.5%	2.4%	2.4%	*4.0%*	*4.5%*	*4.5%*	Retained to Com Eq	*3.5%*
74%	77%	82%	85%	78%	72%	73%	74%	74%	64%	*63%*	*63%*	All Div'ds to Net Prof	*69%*

CURRENT POSITION ($MILL.)	2012	2013	12/31/14
Cash Assets	4.0	7.6	1.5
Accounts Receivable	6.4	3.8	4.0
Other	1.2	3.8	5.7
Current Assets	11.6	15.2	11.2
Accts Payable	1.1	1.8	1.6
Debt Due	.1	--	--
Other	4.3	6.0	4.3
Current Liab.	5.5	7.8	5.9
Fix. Chg. Cov.	414%	417%	417%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	4.5%	3.0%	*5.5%*
"Cash Flow"	6.5%	6.5%	*6.5%*
Earnings	5.5%	5.0%	*6.5%*
Dividends	4.5%	2.5%	*5.0%*
Book Value	7.0%	5.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	9.6	10.4	11.0	10.4	41.4
2013	10.1	10.7	10.9	10.7	42.4
2014	10.6	11.8	12.0	11.5	45.9
2015	*11.0*	*12.0*	*12.5*	*12.5*	*48.0*
2016	*11.5*	*12.5*	*13.0*	*13.0*	*50.0*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.15	.17	.22	.18	.72
2013	.17	.18	.19	.21	.75
2014	.16	.22	.23	.28	.89
2015	*.19*	*.25*	*.26*	*.25*	*.95*
2016	*.20*	*.26*	*.28*	*.26*	*1.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.131	.131	.131	.131	.524
2012	.134	.134	.134	.134	.535
2013	.138	.138	.138	.138	.552
2014	.1431	.1431	.1431	.1431	.572
2015	.1495	.1495			

BUSINESS: The York Water Company is the oldest investor-owned regulated water utility in the United States. It has operated continuously since 1816. As of December 31, 2014, the company's average daily availability was 35.2 million gallons and its service territory had an estimated population of 190,000. Has more than 65,100 customers. Residential customers accounted for 63% of 2014 revenues; commercial and industrial (29%); other (8%). It also provides sewer billing services. Incorporated: PA. York had 106 full-time employees at 12/31/14. President/CEO: Jeffrey R. Hines. Officers/directors own 1.1% of the common stock (4/15 proxy). Address: 130 East Market Street York, Pennsylvania 17401. Telephone: (717) 845-3601. Internet: www.yorkwater.com.

York Water had a strong finish in 2014. Share earnings came in at $0.28, $0.04 above our fourth-quarter estimate, which was actually a few cents higher than the Wall Street consensus. For the full year, the company was able to post a robust 19% year-over-year increase in the bottom line.

Earnings growth should moderate, but remain solid. The December interim's gains were due to a combination of a lower tax rate, better cost controls, and higher tariffs being in effect. Although the rate relief will not have as large an impact on profits going forward, we still expect York to benefit from a reduced tax burden and a successful cost-containment program. All told, we expect earnings per share to rise 7% this year, to $0.95, and increase by a nickel in 2016, to $1.00.

Capital spending has picked up. As is the case with almost all of its peers, the company is in the process of repairing and modernizing an aging pipeline and wastewater infrastructure. Last year, construction expenditures rose a hefty 40% as management targeted more funds for this purpose. We believe that the budget will remain near this level through the end of the decade.

The balance sheet is strong enough to handle these expenses. At the end of 2014, York's equity-to-total capital ratio stood at 55%, much higher than the industry norm. And, even though we expect this metric to weaken, we estimate that it will still be a healthy 52% in three to five years.

York shares are expected to perform in line with the broader market averages in the year ahead. True, the company's earnings outlook is improving and the stock's yield is 50 basis points higher than the typical stock followed by *Value Line*. However, these positive attributes appear to be already incorporated into the price of the stock. Indeed, the equity's long-term potential returns are unattractive as it is already trading well within our projected 2018-2020 Target Price Range. Those investors seeking safety, current income, and well-defined earnings, as well as good dividend growth, can probably find a better selection in the water utility industry.

James A. Flood *April 17, 2015*

(A) Diluted earnings. Next earnings report due mid-May.
(B) Dividends historically paid in mid-January, April, July, and October.
(C) In millions, adjusted for splits.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	100

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 210

Security Market Trends
(What News Are Investors Experiencing?)

Exhibits in Support
of Opening Testimony

October 16, 2015

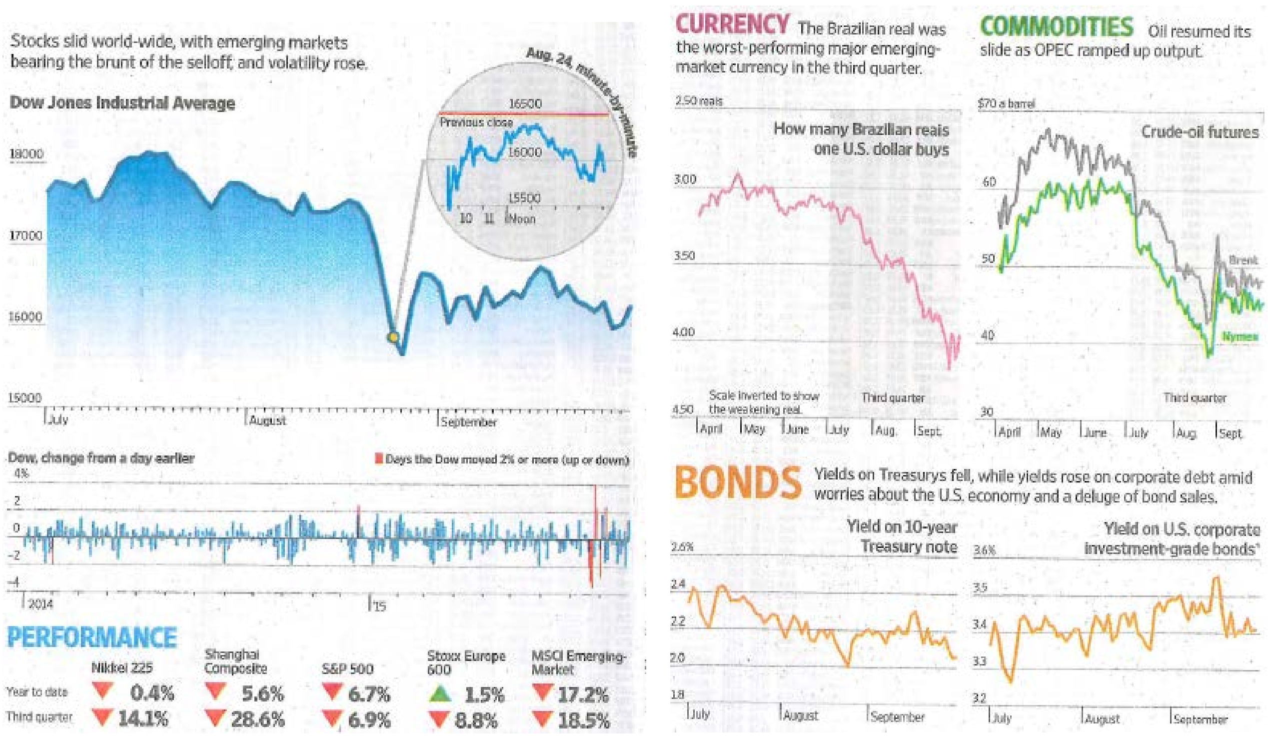
Wall Street Journal Quarterly Overview — October 1, 2015:

Worries about the ripple effects from China's economic slowdown hammered global markets in the third quarter and sent investors into safer assets such as U.S. government bonds. A rout in commodities deepened, pulling many emerging market currencies to record lows against the dollar.

July 15 — Greece passed austerity measures to secure bailout

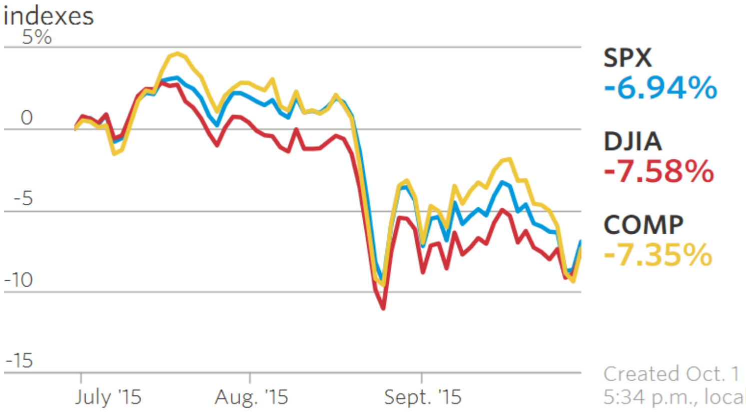
Aug. 11 — China unexpectedly devalued its currency, rattling markets

Sept. 17 — Federal Reserve kept interest rates near zero.



A Quarter to Forget

Change in the third quarter in the S&P 500 (blue), DJ Industrials (red) and Nasdaq composite (yellow) stock indexes



Source: WSJ Market Data Group

U.S. stocks limped into October, following the worst quarter for benchmark indexes since 2011.

Spreads

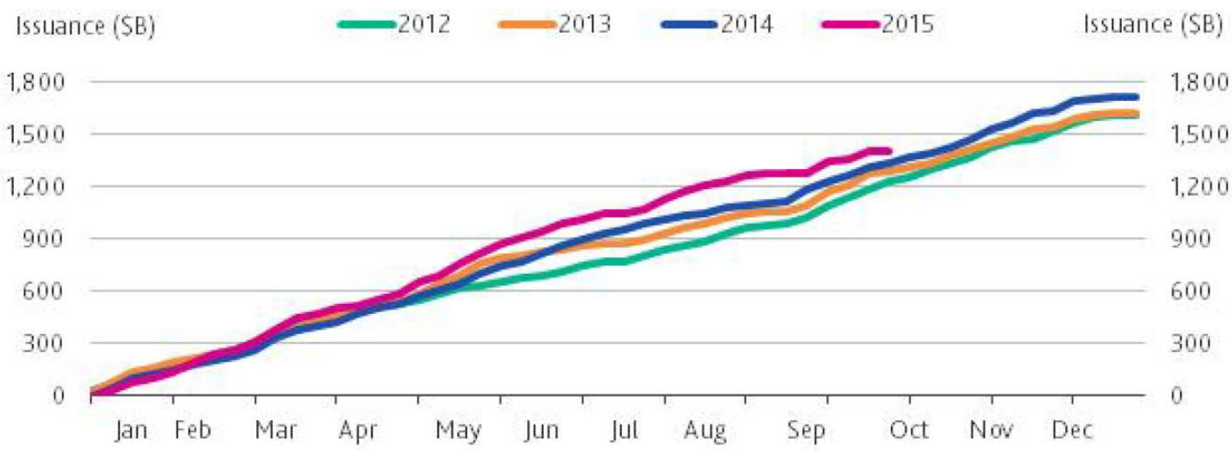
Excerpts from Moody's Capital Market Research, Inc. (CMR) — Oct. 1, 2015

Analyses from Moody's Capital Markets Research, Inc. (CMR) focus on explaining signals from the credit and equity markets. This publication addresses whether market signals, in the opinion of the group's analysts, accurately reflect the risks and investment opportunities associated with issuers and sectors. CMR research thus complements the fundamentally-oriented research offered by Moody's Investors Service (MIS), the rating agency.

CMR is part of Moody's Analytics, which is one of the two operating businesses of Moody's Corporation. Moody's Analytics (including CMR) is legally and organizationally separated from Moody's Investors Service and operates on an arm's length basis from the ratings business. CMR does not provide investment advisory services or products.

5-Year Median Credit Spreads – High Grade

Market Cumulative Issuance of USD Denominated Corporate & Financial Institutions



USD denominated investment grade issuances examined for corporate and financial institutions was $10.9B on a weekly and $1.036T on an annual basis. North American median Credit Default Spreads (CDS).

CDS Implied Ratings Rises:

Issuer	Sep. 30	Sep. 23	Senior Ratings
SunGard Data Systems Inc.	Baa3	Ba2	B3
Freescale Semiconductor, Inc.	A3	Baa2	Caa1
Alcatel-Lucent USA, Inc.	Baa3	Ba2	B2
Ford Motor Credit Company LLC	Baa3	Ba1	Baa3
Wal-Mart Stores, Inc.	Aa3	A1	Aa2
Microsoft Corporation	Aa3	A1	Aaa
Johnson & Johnson	Aa1	Aa2	Aaa
Target Corporation	Aa2	Aa3	A2
Union Pacific Corporation	Aa2	Aa3	A3
Simon Property Group, L.P.	A1	A2	A2

CDS Implied Ratings Declines:

Issuer	Sep. 30	Sep. 23	Senior Ratings
Caterpillar Inc.	Baa2	A3	A2
Archer-Daniels-Midland Company	Baa1	A2	A2
Eastman Chemical Company	Baa3	Baa1	Baa2
Molson Coors Brewing Company	Baa2	A3	Baa2
Bank of America Corporation	Baa2	Baa1	Baa1
John Deere Capital Corporation	A3	A2	A2
Caterpillar Financial Services Corporation	Baa2	Baa1	A2
Time Warner Inc.	Baa1	A3	Baa2
Dow Chemical Company (The)	Baa3	Baa2	Baa2
Kinder Morgan Energy Partners, L.P.	Ba3	Ba2	Baa3

CDS Spread Increases:

Issuer	Senior Ratings	Sep. 30	Sep. 23	Spread Diff
Peabody Energy Corporation	Caa2	6,130	5,090	1,039
Sprint Communications, Inc.	B1	904	661	244
iHeartCommunications, Inc.	Ca	3,842	3,625	217
Chesapeake Energy Corporation	Ba1	1,248	1,036	212
Cablevision Systems Corporation	B1	580	396	184
Toys 'R' US, Inc.	Caa2	2,112	1,970	142
United States Steel Corporation	B1	1,329	1,190	139
Williams Companies, Inc. (The)	Baa3	370	234	136
MBIA Insurance Corporation	B3	1,937	1,831	106
Freeport-McMoRan Inc.	Baa3	669	567	103

(Continued on next page)

CDS Spread Decreases

Issuer	Senior Ratings	Sep. 30	Sep. 23	Spread Diff
HealthSouth Corporation	B1	293	333	-40
Alcatel-Lucent USA, Inc.	B2	116	155	-39
Commercial Metals Company	Ba2	231	267	-36
AutoNation, Inc.	Baa3	452	476	-25
Juniper Networks, Inc.	Baa2	99	116	-18
SunGard Data Systems Inc.	B3	137	153	-17
Freescale Semiconductor, Inc.	Caa1	69	85	-16
Crown Castle International Corp.	Ba3	292	308	-15
Navistar International Corp.	Caa1	609	623	-14
Dole Food Company, Inc.	Caa1	260	272	-13

Data Source: Moody's

Market Isn't Buying Fed on Inflation

by Min Zeng — WSJ — Oct. 1, 2015

The lack of inflation made itself felt in the bond market this quarter.

While Treasury bonds chalked up a price rally this quarter, their sibling–Treasury inflation protected securities — have taken a heavy beating, set for the biggest quarterly loss in a year.

Treasury debt overall has handed investors a total return — including price gains and interest payments — of 1.82% between the end of June and Tuesday, according to data from Barclays PLC. TIPS have lost 1.2% during the same period.

The key driver: inflation expectation in the bond market has plunged to five-year low amid worries over **sluggish global growth and disinflationary pressure**. U.S. consumer price index for August rose 0.2% on an annualized base and excluding food and energy, the reading was 1.8%. Inflation has been running below the Fed's 2% target for 40th consecutive months.

Treasury bonds, especially long-term debt, are vulnerable if consumer prices rise as that will chip away their fixed returns. TIPS offer protection against inflation by boosting principal repayments once inflation breaches a certain threshold.

Over the past few months, worries over **slower growth in China, lower commodity prices and plunging emerging-market currencies all deflated inflation** fear, encouraging investors to favor U.S. Treasury debt over TIPS. **A gauge of inflation expectation, the yield spread between a 10-year Treasury note and 10-year TIPS, tumbled to the lowest level since 2009 earlier this week**. The **yield spread suggested Wednesday that U.S. Inflation will run at an annualized 1.42% on average within a decade, well below the Fed's target of 2%**.

"TIPs have cheapened up relentlessly in recent weeks given the global disinflationary pressure," said Lynn Chen, senior portfolio manager at Aberdeen Asset Management, which has $483.3 billion assets under management.

Investors pulled $60 million of net cash out of U.S. bond mutual funds and ETFs focusing on TIPS for the week ending Sept 23, according to Lipper. The sector has suffered outflows for eight of the past nine weeks.

Ms. Chen said the selloff has made TIPS more attractive, though she said she is not stepping in to buy at the moment given the global uncertainties.

TIPS "are always good to own as part of a broadly diversified portfolio as they hedge against unexpected inflation," said Gemma Wright-Casparius, senior portfolio manager at The Vanguard Group. "They appear attractive, but with the Fed likely to hike in the fourth quarter of 2015, I would wait before buying."

FOMC Leaves Rates Untouched

by Robb Soukup — SNl Financial LC — Sep. 17, 2015

The Federal Open Market Committee on Sept. 17 said it was **leaving** the **federal funds rate u**nchanged.

The **target range** for the federal funds rate **remains at between zero and 0.25%**, the committee said in its policy statement. There had been widespread **speculation** ahead of the meeting that the **bank could lift rates for the first time in nine years**. **But policymakers demurred**, saying the committee will not lift rates until it sees "further improvement in the labor market and is reasonably confident that inflation will move back to its 2% objective over the medium term."

Policymakers continued to emphasize improvements in the committee's assessment of the broader economy. It noted improving housing, as well as "solid" job gains paired with declining unemployment.

It added that it anticipates that "economic activity will expand at a moderate pace," with continued improvements in labor markets. The committee members also said that while they expect to continue to see low inflation numbers in the short-run, they **expect that inflation will rise closer to its 2% target over the medium term**.

The committee stressed that even **when** it does decide to **begin policy normalization**, it will **likely leave rates below levels it would view as normal in the long-run**.

Nine members of the committee **voted** in **favor** of the **policy action**; **Federal Reserve Bank** of **Richmond** President Jeffrey Lacker voted against it. Lacker "preferred to raise the target range for the federal funds rate by 25 basis points at the meeting," according to the statement.

Risks Grow for Slow but Steady U.S. Expansion

by Jon Hilsenrath and Nick Timiraos – WSJ – Aug. 24, 2015

Market turmoil and China's troubles threaten to undermine outlook for world's largest economy

Federal Reserve Chairwoman Janet Yellen, shown in Washington last month, faces a tougher decision whether to begin raising interest-rates later this year after the recent stock-market declines

The **U.S. has been the tortoise in a global race for economic growth, plodding out a slow but steady expansion** while China signals exhaustion and the rest of the world wobbles. Now, market turmoil and China's troubles threaten to undermine the already unspectacular U.S. outlook.

Few economists see a U.S. recession. In fact, some recent developments, including lower oil prices, will help U.S. consumers and businesses.

But an **uneven global growth outlook is pushing the value of the dollar higher**, making U.S. goods more expensive overseas and harder to export. That could restrain the U.S. economy in the months ahead. Stock-market declines could further hurt U.S. consumer sentiment and spending, if the drops are sustained, and they make businesses even less willing to invest.

Federal Reserve officials now need to decide if they should alter their planned course on interest rates. Officials have been signaling for months that at least one increase in short-term rates is likely this year, possibly as soon as September.

Now, Fed officials might rethink the timing and pace of their plans, thanks to an uncertain growth and inflation outlook. In futures markets, **investors put the odds of a rate increase in September at just 24%, according to the Chicago Mercantile Exchange**; **a week ago, it was rated a tossup**.

The stakes are high. Asset values could tumble without the support of continued low rates. Investors also worry policy makers lack tools to intervene in the economy should it sink again.

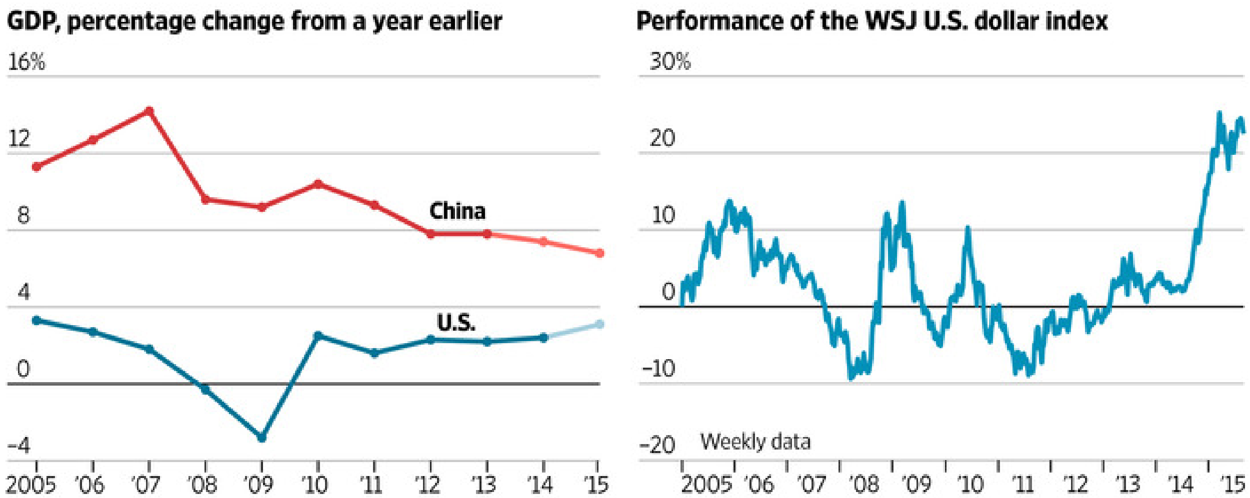
Atlanta Fed President Dennis Lockhart, who said earlier this month he was inclined to move rates up in September, said in a speech on Monday that he sees an increase this year, but he avoided attaching a date to it.

"The **Fed should not be raising rates**," **said** Lawrence Summers, a **Harvard University professor and former Obama administration adviser, in an interview**. "It should be thinking about its contingency plans if financial distress becomes serious. It should signal that it won't be raising rates until and unless it sees clear evidence of inflation breaking above 2% or clear evidence of euphoria in financial markets."

Such views increase public pressure on Fed Chairwoman Janet Yellen to stand pat. Merely talking about rate increases in the absence of inflation or a financial boom would be counterproductive at this point, Mr. Summers said.

Tortoise or Hare?

The U.S. has posted steady but unremarkable growth over the past six years, while China's rapidly expanding economy has downshifted. Stronger U.S. growth has led to a surge in the dollar, causing heartburn for American exporters.



Note: GDP estimates, China 2014-15, U.S. 2015

Sources: International Monetary Fund (GDP); WSJ Market Data Group (dollar index)

THE WALL STREET JOURNAL.

Investors, struggling to make sense of a resilient U.S. economy buffeted by threats from abroad, went both ways on **Monday**. The **Dow Jones Industrial Average dropped more than 1000 points at its open, reversed course, drifted lower again and closed down almost 600 points**.

"People are scratching their heads how the economy is doing better as markets are doing worse," said David Rosenberg, chief economist at money-management firm

Gluskin Sheff & Associates. "The markets and the economy don't always have to correlate at any given point in time."

The U.S. has managed 2.1% annual growth since emerging from recession in 2009, rarely veering much above or below that pace, even when China slowed and Japan and Europe experienced secondary downturns.

The sluggish U.S. expansion has unfolded amid unprecedented support from the Fed, which has kept its benchmark federal-funds rate pinned near zero since December 2008 and launched several rounds of bond-buying programs to boost investment.

Economists surveyed by The Wall Street Journal expect the Commerce Department to report later this week that U.S. economic output expanded at a 3.3% annual rate in the second quarter, faster than previously reported.

Recent reports on retail sales and housing investment suggest output is expanding at a pace of 2.4% in the third quarter, according to analysts at Macroeconomic Advisers, a research firm.

The modest rebound Fed officials expected earlier in the year for now at least appears to be playing out. Weighing against threats from abroad are domestic sectors like autos and housing. Sales of previously owned homes are running at their highest levels since 2007, and home prices have rebounded strongly.

Home Depot reported last week that sales at stores open at least one year rose 4.2% in the second quarter and 5.7% in the U.S. The company raised its earnings guidance for the second time this year, and executives last week called out improvements in their division that caters to contractors, which they said reflected the continued rebound in home prices.

"When consumers believe their home is an investment and not an expense, they spend differently, and we're seeing that spend pattern," Carol Tomé, the company's finance chief, told analysts.

Meantime, falling gasoline prices have delivered a boost to restaurants and bars, which have reported their best sales growth in years, and are ramping up hiring amid increased competition for workers. Chipotle Mexican Grill Inc. announced plans Sunday to hire 4,000 employees in a single day next month, around 7% of its workforce.

Falling gasoline prices are more meaningful than Wall Street's gyrations to most working-class Americans, "who don't care where Apple stock is trading," said Andy Puzder, chief executive of CKE Restaurants Inc., which operates the Carl's Jr. and Hardee's burger chains. He said the closely held company plans to add a substantial number of restaurants in the U.S. this year.

Many U.S. companies find themselves trying to navigate a two-tiered global outlook, marked by small gains at home and new worries in China and Asia, a stark contrast from China's boom days of a few years ago.

Examples of the global disconnect were ample in recent U.S. company earnings reports:

Attendance at Disney parks in the U.S. rose a steady 4% in the quarter ended in June, while it declined in Hong Kong.

Ford Motor Corp.'s North American revenue rose 4.1% in the first half of the year, while it dropped 14.5% in Asia.

At Wynn Resorts, the global gaming company, gamblers cut back 27.6% in slot-machine use in Macau, China, in the latest quarter, while inching up their use by 1.6% in Las Vegas.

"In Las Vegas, we are enjoying a comfortable business. I think that is the right word for it," said Steve Wynn, the chief executive of the gaming company, in a conference call with analysts last month. His big bets on Macau, meanwhile, were "more of a question than a certainty."

China by itself is not an obvious threat to the U.S. economy. **China accounts for 21% of U.S. imports of goods and services**. That gives it big influence on U.S. consumer prices and wages. **However, it accounts for only 7% of U.S. exports**. Because exports themselves aren't a big driver of U.S. growth, the hit from a slowdown of sales to China is bound to be small. **But broader spillovers from China's slowdown could pose challenges for U.S. companies and the economy**.

Many companies are still investing heavily in the world's second-largest economy. Wynn, for example, is planning to open a $4.1 billion, 1,700 room hotel called Wynn Palace in Macau in March. Disney recently announced plans to open a new theme park in Shanghai. If growth doesn't materialize in these and other ventures, it could knock the profitability of multinationals.

Then there is the U.S. dollar, which has appreciated nearly 8% against a broad basket of currencies so far this year, according to the Fed. The move was amplified earlier this month, when Beijing allowed the yuan to depreciate.

Economists at Goldman Sachs estimate a worsening U.S. trade position will subtract 0.75 to 1.00 percentage point from the already slow U.S. growth rate in the coming year, worse than the 0.6 percentage point that trade pulled from growth in the past year. That is **not enough to short-circuit the recovery**, but it is **enough to keep restraining it**.

A **stronger dollar also holds down inflation** by restraining the price of imported goods, which were down 10.4% in July from a year earlier. Besides the 2007-2009 global financial crisis, declines of that magnitude haven't occurred in government records going back to 1982.

The Fed has said it won't raise short-term interest rates until officials are "reasonably confident" that inflation will rise toward 2% after running below it for more than three years. The stronger dollar and falling oil prices are bound to undermine that confidence.

The timing of an interest-rate increase is only one variable officials must consider in the weeks ahead. Another is the pace of rate increases the central bank plans for the years ahead.

In forecasts released in June, Fed officials estimated the benchmark Fed funds rate would be 1.625% by the end of 2016 and 2.875% by the end of 2017. **Yields on two-year Treasury notes were 0.601% on Monday, suggesting investors don't believe officials will move nearly as much as projected**.

But keeping rates low carries its own set of risks. One is that it could stoke a new financial bubble.

The **U.S. stock market, now in correction territory, is hardly screaming bubble**. **But other sectors look stretched**. U.S. regulators, for instance, have expressed concern recently about commercial real estate. "Now is not the time to be overly aggressive in bidding," said Chris Finlay, CEO of Lloyd Jones Capital, a boutique firm in Miami that invests primarily in multifamily properties.

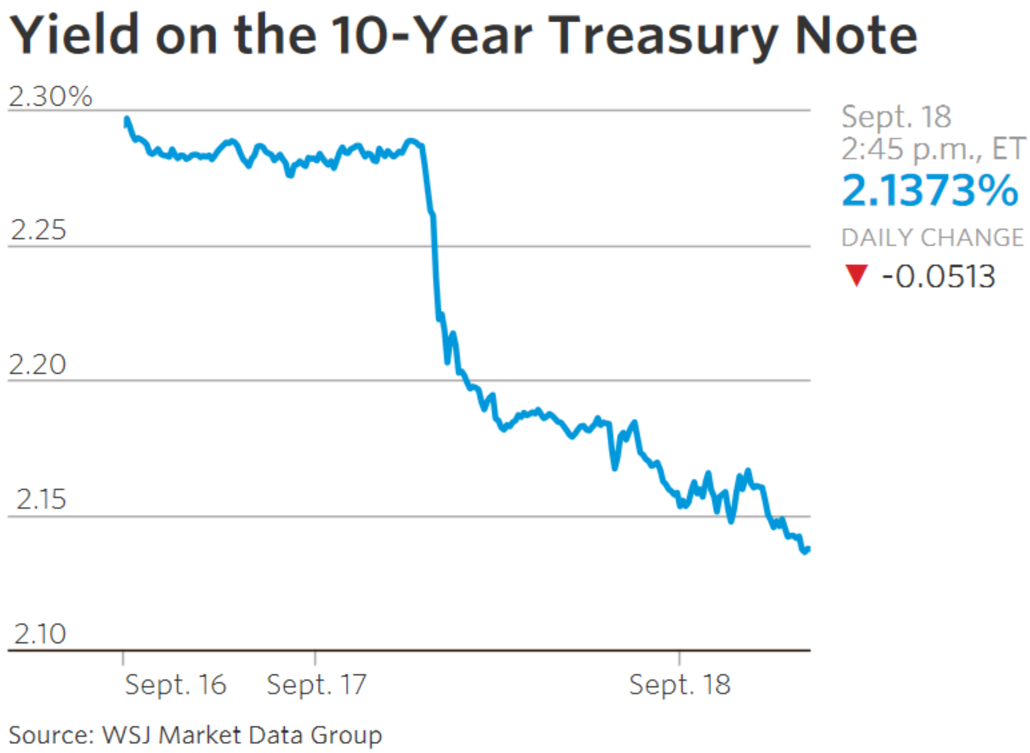
In a note to clients, Mr. Finlay warned that too much capital was chasing apartments. The firm recently bid on a distressed $6 million apartment complex in Tallahassee, Fla., that was just 85% occupied. The sale drew 21 bidders – normally such a sale would draw around five or six, he said – and the winning bid offered a $500,000 nonrefundable cash down payment before conducting due diligence.

"That's just not good business sense," said Mr. Finlay.

Global Government Bond Yields Fall on Fed, ECB Outlook

by Ming Zeng — WSJ — min.zeng@wsj.com — Sep. 18, 2015

Fed's decision to hold the line on rates deters move into riskier assets



Government bond yields on both sides of the Atlantic tumbled Friday as stocks declined one day after the Federal Reserve left short-term interest rates unchanged and generated anxiety in financial markets.

The Fed's decision to hold short-term rates near zero for a longer period failed to boost investors' confidence to buy riskier assets. Instead, the Fed's signal Thursday over concerns about the global economy, especially the slowdown in China, pushed down global stocks Friday and boosted the relative safety in sovereign bonds in rich countries.

"It was the first time the Fed was so specific about external factors" in influencing the U.S. monetary policy outlook and the "lingering issue of a rate increase" remains unresolved, said John Briggs, head of strategy for Americas at RBS Securities. "Investors are confused and concerned," he said.

An additional boost for bonds came from comments from **European Central Bank** Executive Board member Benoît Coeuré, who **said Friday that the bank has flexibility to extend bond buying beyond September 2016 if needed**. The comment bolstered expectations that more monetary stimulus may be up before the end of this year, which energized buyers into the euro-zone's bond markets.

Lower bond yields in Europe make higher-yielding U.S. Treasury debt more attractive for buyers, highlighting investors' struggle to obtain assets that offer liquidity and income amid sluggish global growth, subdued inflation and continued uncertainty over when the Fed would start its first tightening campaign since 2006.

In recent trading, the yield on the benchmark 10-year Treasury note was 2.146%, compared with 2.215% Thursday, according to Tradeweb. Yields fall as bond prices rise.

The **yield on the two-year note fell to 0.682% from 0.702% Thur**sday.

The **two-year yield posted the biggest one-day drop Thursday since December 2010 following the Fed's decision**. **Yields on short-term notes, such as those maturing between two years and five years, are highly sensitive to changes in the Fed's interest-rate policy outlook**. The yield on the two-year note had closed Wednesday at a four-year high of 0.811%.

The Fed's ultra-loose monetary policy since the financial crisis has pushed up Treasury bond prices to historically elevated levels and bond investors are concerned that the value of bonds may fall once the Fed shifts gear into a tightening mode. **Higher interest rates typically make newly minted bonds more attractive and shrink the value of outstanding bonds**.

Fed officials signaled that a rate increase before the end of the year is still on the table, but expectation in the financial markets is growing that the Fed might wait until 2016 to raise rates, which drove buyers into bonds.

Fed-funds futures, used by investors and traders to place bets on central bank policy, showed Friday that bettors see a 14% likelihood of a rate increase for the Fed's October policy meeting, according to data from CME Group. The odds of a rate increase at the December meeting were 41%.

Lower long-term Treasury bond yields are compounding expectations by investors and traders who predict that yields should rise this year to reflect an improving U.S. economy and a pending shift by the Fed on monetary policy.

These bets panned out earlier this year as the 10-year yield reached 2.5% in June, the highest intraday level since September 2014. The yield has since tumbled as worries over China's economy and stock market have stoked demand for haven bonds.

"It is hard to bet against long-term Treasury bonds,'' said David Coard, head of fixed-income trading in New York at Williams Capital Group. "I need to remind myself again and again that we are not living in normal time. **Yields are not going to spike given the global uncertainty**."

U.S. bond yields remain more attractive among high-income countries. Friday, the 10-year German bond yield fell to 0.657%, the 10-year U.K. bond yield declined to 1.831% and the 10-year French bond yield slid to 0.952%, according to Tradeweb.

Another appeal to buy long-term bonds: tame inflation. The **value of long-term bonds is less influenced by the Fed's short-term interest-rate policy and more influenced by global growth and the inflation outlook**. **Inflation is the main threat because it chips away bonds' fixed return over time**.

Lower commodities have reduced inflation expectations in the U.S. where the Fed has failed to push inflation higher to its 2% target. **China's surprise decision last month to weaken the Chinese yuan has sent many emerging-market currencies tumbling against the dollar**, adding to **disinflationary pre**ssure and **increasing the appeal of long-term Treasury bonds**.

Some investors see one risk to buy long-term debt: sales of long-term Treasury debt by foreign central banks to raise cash to support local economies, fight against capital outflow or support flagging economic growth.

China, the largest foreign owner of U.S. government securities, **shed Treasury debt holdings in July,** according to data from the Treasury earlier this week. Traders and analysts said China has sold long-term Treasury bonds following its move to weaken the yuan in August, which had prevented bond yields from falling significantly amid a recent stock-market swoon.

"This is a short term concern but there are other factors that would provide support for long-term bonds," said Patrick Maldari, money manager at Aberdeen Asset Management, which has $483.3 billion in global assets under management.

U.S. 10-Year Note Closes Below 2%

by Ming Zeng – WSJ – Aug. 24, 2015

A Deepening rout in global stocks and commodities sending investors to the safe harbor of U.S. debt. **Chinese** stocks nosedived Monday with the benchmark **Shanghai Composite Index dropping 8.49%**.

Rising demand for haven assets on Monday sent the yield on the **benchmark 10-year U.S. government note below 2%** for the first time since April as a rout in global stock and crude oil markets deepened.

The flight for safety has been gathering speed over the past few weeks, underscoring growing anxiety over China's slowing economy and its stock market rout, which has rippled through markets globally and clouded the global economic outlook.

The uncertainty over whether the Federal Reserve will raise interest rates next month or wait longer to act has contributed to growing volatility in riskier assets, driving many to shed their risk appetites and shift focus to preserve capital.

"This is a **flight to quality** and the actual level that the Treasury yield achieves in this environment is not meaningful," said David Keeble, global head of fixed-income strategy at Crédit Agricole. "This is a time when you dig a deep hole, close your eyes and put your fingers in your ears."

On Monday, U.S. stocks and European equities fell sharply as a rout in Chinese shares accelerated, wiping out gains for the year. U.S. oil prices tumbled by 5.5% on Monday and settled below $40 a barrel for the first time since February 2009. A gauge of 10-year inflation expectation in the U.S. bond market fell to the lowest level since 2009.

As investors sought shelter in Treasury debt, the yield on the benchmark 10-year Treasury note fell to 1.997% in late-afternoon trading from 2.052% on Friday. It marks the lowest closing level since April 28. Yields fall as prices rise.

Growing turmoil is heaping pressure on global central banks to act. If policy makers take actions to soothe investors' fears about markets and growth, demand for haven assets could wane, sending yields higher, say some traders. On Sunday, The Wall Street Journal reported that China's central bank is preparing to bolster liquidity in the country's banking system.

Ray Uy, senior portfolio manager at Invesco Ltd., which has $803.6 billion in assets under management, says with rising volatility and a lot of uncertainties, "it is risky to step into markets that are getting hit" even though some asset classes are getting cheaper from the market rout.

The **10-year yield**, a foundation for global finance and a key indicator of investors' sentiment toward growth and inflation, has **plunged from 2.5% in June**. Anxiety has been growing over the global economy amid lower commodities prices, plunging emerging-market assets and a selloff in both stocks and bonds sold by lower-rated U.S. companies, known as junk bonds.

China's surprising move to devalue the yuan earlier this month amid tumbling exports heightened concerns over the pace of the world's second-largest economy, which has been a big buyer of commodities, including iron ore, copper and oil. Last Friday, a report showed a gauge of China's manufacturing sector dropped to its lowest level in 6 1/2 years.

Rising volatility in financial markets and falling inflation expectations are complicating the Fed's plan to raise interest rates for the first time since 2006. The U.S. economy has been strengthening after a soft patch earlier this year. Solid jobs growth has bolstered the case for the Fed to start moving away from crisis-era monetary stimulus. The **Fed's ultra-loose monetary policy has boosted prices of a wide range of financial assets over the past years and now investors are concerned whether these assets may fall in value once the Fed shifts gears into a tightening mode**.

The nonfarm jobs report for August is due to be released in early September. Analysts say a strong report may allow the central bank to act at its Sept. 16-17 policy meeting. Yet many investors say global uncertainties and rising volatility in many asset markets could make the Fed wait longer to act. They are concerned that a rate increase could jolt sentiment and roil already jumpy markets.

Fed-funds futures, used by investors and traders to place bets on central bank policy, **showed Monday that investors and traders see a 24% likelihood of a rate increase at the September 2015 meeting, according to data from** the CME Group. **A couple of weeks ago, the odds were around 50%**.

"There are fears that global growth is going to come crashing down," said **Thomas Roth, executive director in the U.S. government bond trading group at Mitsubishi UFJ Securities** (USA) Inc. in New York. "**A week ago we were thinking the U.S. economy was strong enough for a Fed rate hike and now we fear a global recession. It is amazing how quickly things can change**."

As expectations on the Fed to tighten next month pulled back, the **yield on the two-year Treasury note fell to 0.568% Monday**, the lowest closing level since July 8, from 0.629% Friday. The yield is **highly sensitive to changes in the Fed's interest rate policy outlook**.

China's Central Bank Cuts Interest Rates

by Lingling Wei – WSJ – Aug. 25, 2015

Grace Zhu and Mark Magnier contributed to this article.

PBOC cut interest rates by one-quarter of a percentage point, and lowered banks' reserve-requirement ratio.

The PBOC also dropped a key control on rates for some bank deposits, allowing lenders greater freedom to compete for business.

China stepped up its credit-easing efforts by slashing interest rates and flooding its banking system with new liquidity, its second such combo move in two months aimed at battling a deepening economic slowdown and its worst stock-market selloff in decades.

The **People's Bank of China** announced the one-two punch late Tuesday after the **country's main stock index fell another 7.6%, bring losses to more than $1 trillion in market value over the past four trading days**. The stock rout was triggered by growing doubts among investors over the government's ability to avoid a hard landing of the world's No. 2 economy.

Concerns over China's economic health have also **roiled global markets** in recent days, prompting the Chinese central bank to take action. In a statement posted on its website, the **PBOC** – dubbed "Yang Ma," or Big Mama, within China – noted the "big fluctuations" in financial markets around the world, which prompted it to "make flexible use" of monetary-policy tools to ensure steady growth.

China has targeted year-over-year economy growth of about 7% for 2015, which already would be the slowest pace in a quarter century. New data since July has called its ability to hit that target into question. In particular, a private-sector gauge of factory activity fell to a 77-month low in August. Meanwhile, a **surprise** 2% **devaluation** earlier this month of the country's currency, the **yuan**, was interpreted by investors as a sign that economic growth is slowing more than Beijing had anticipated.

An interest-rate cut by China's central bank added fuel to a rally in European stocks and U.S. stock futures despite another sharp drop in Chinese shares.

"China's economy will get worse before it gets better," said Yu Yongding, a prominent Chinese economist and a former adviser to the central bank.

Chinese companies are struggling with high debt loads and low prices, said Mr. Yu. Persistently low factory-output prices and still-low consumer prices have put disinflationary pressure on the Chinese economy and led to worries that China could enter deflation, which pushes up borrowing costs and makes it more difficult for businesses to service debt.

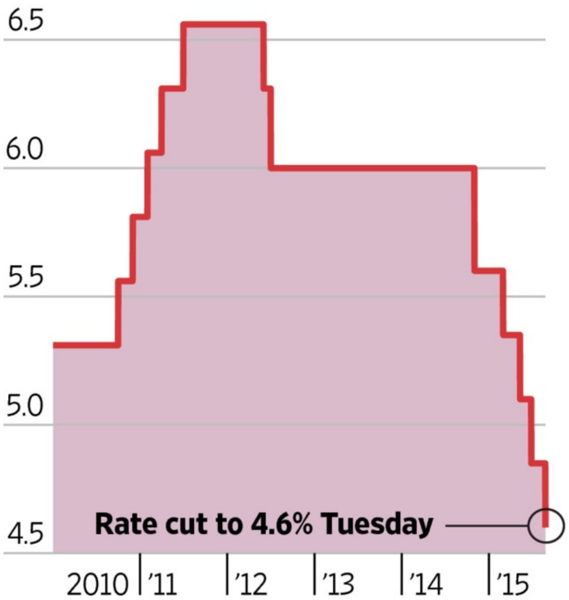
"China has entered a stage of deflation," he said, pointing to the factory and consumer-price data. To maintain economic stability **in the short** run, Mr. Yu said, "it's inevitable for the Chinese central bank to **ease credit**."

The issue for investors is whether the latest easing steps will help restore – or further hurt – their confidence in Beijing's handling of the economy and markets. "One key question is whether these measures will gain much traction at a time of slipping confidence and weakening growth momentum," said Eswar Prasad, a Cornell University professor and former China head for the International Monetary Fund.

Cut-Rate Cash

China's central bank cut interest rates after days of market turmoil.

One-year benchmark lending rate



Source: People's Bank of China
THE WALL STREET JOURNAL.

With Tuesday's moves, the Chinese central bank has cut interest rates for the fifth time since November and broadly lowered for the third time the amount of deposits banks are required to hold in reserve. It is rare for the PBOC to simultaneously cut interest rates and banks' reserve requirements. The last time it made the combo move was June 27, soon after Chinese stocks started to sell off.

In the past two months, China has accelerated monetary easing to shore up stock prices and stabilize the economy. But some of its efforts – especially its heavy intervention in the stock market and recent currency moves – have also called into question the government's ability to effectively manage the economy.

So far, the steps have largely failed to lift market sentiment as investors kept pushing down share prices. The central bank's recent handling of the Chinese yuan also raised eyebrows among investors and economists.

On Aug. 11, the PBOC unexpectedly devalued the yuan by setting its official rate nearly 2% weaker in a move it said was intended to bring the yuan's value more in line with market expectations. The surprise action prompted investors to sell the yuan both on the mainland and in what is known as the Hong Kong offshore market in expectations it would go still lower.

China limits the yuan's daily trading on the mainland to a tight band, but under a new policy its value is supposed to be determined more by daily trading moves. To contain those moves, PBOC has frequently bought the yuan and sold the U.S. dollar to prevent the Chinese currency from falling too much. Analysts at Orient Securities Co., a Shanghai brokerage, estimate that the PBOC has spent more than $40 billion of China's roughly $3.7 trillion foreign-exchange reserves. It could become costlier if the market continues to drive the yuan down.

The interference also has had the effect of draining yuan funds out of the market – threatening to cause a shortage of funds at Chinese banks that already are battling with rising bad-loan levels and falling profitability. The Wall Street Journal reported on

Sunday that the PBOC was planning to flood the financial system with new liquidity in a bid to counter that liquidity squeeze.

The half-percentage reduction in banks' reserve requirements, which will become effective Sept. 6, will pump about 678 billion yuan, or roughly $105.7 billion, worth of funds into China's banking system. After the interest-rate cuts, which will be effective Wednesday, China's benchmark one-year lending rate will be lowered to 4.6% from 4.85% previously, and the one-year deposit rate will fall to 1.75% from 2%.

PBOC officials hope that the new funds will encourage Chinese lenders to make more loans to help the part of the economy that can generate jobs and boost productivity. However, based on recent official data, credit to those areas slumped in July, while lending to financial institutions surged amid the government's efforts to prop up the stock market.

In a nod to reforms, the PBOC on Tuesday also dropped a key control on rates for some bank deposits, allowing lenders greater freedom to compete for business. However, the central bank still refrained from fully giving up its control on deposit rates for fear of driving up interest rates and prompting more risk-taking behavior by banks amid a slowing economy, according to people close to the central bank.

In the statement, the **PBOC** said China faces an "arduous task" to **maintain growth and press ahead with overhauling the economy**.

Chinese Retail Investors Flee Plunging Markets

by Wei Gu – WSJ – Aug. 5, 2015

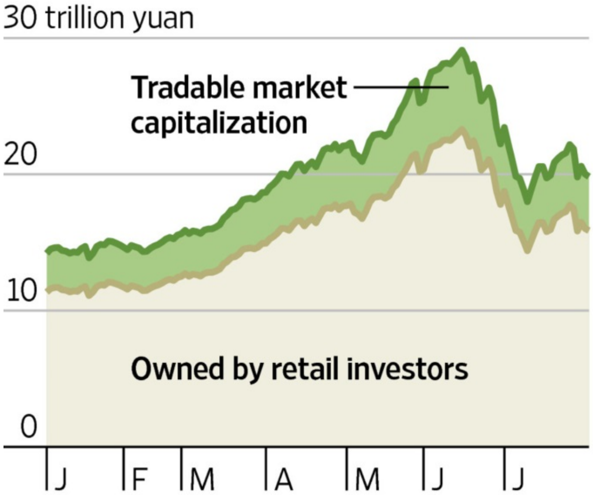
More than 20 million pulled out in July, as Shanghai Composite Index took biggest monthly dive in six years.

Left – Inside a Qingdao brokerage house Friday, as **China's market ended its worst month since 2009 and bid farewell to more than 20 million individual investors**.

China's market selloff can safely be declared a rout.

Nearly a third of the country's individual investors – more than 20 million people – fled the plunging stock markets last month. The number of retail investors holding stocks in their accounts slid to 51 million at the end of July from 75 million at the end of June, according to China Securities Depository & Clearing Corp., the government agency that tracks accounts. As they ran, the Shanghai Composite Index suffered its biggest monthly decline in six years, falling 14% to **finish 29% below its June 12 peak**.

Unlike in the U.S., where institutions dominate stock trading, retail investors are king in China, owning around 80% of listed stocks' tradable shares, according to investment bank CICC.



Note: Based on CICC estimate of retail participation at 80% of free float
Source: Wind Info
THE WALL STREET JOURNAL.

Earlier this year ZZ Xu, a Shanghai restaurateur, put money in the stock market rather than in his business, believing he could get a faster return. He got out before the July rout with his finances intact – indeed, with a profit in the millions of dollars – but his **faith badly shaken**. Mr. Xu recently signed a new lease for a restaurant in Shanghai, and has moved some of the money he held in stocks back into his businesses.

"Now I **realize** I **can lose a lot of money very quickly**," he said, noting that threats to stocks include China's slowing growth and the eventual end of government rescue efforts.

Those frantic rescue efforts couldn't keep back the share-price plunge in Shanghai and Shenzhen, which began in mid-June, from continuing through most of July. When the month ended, **investors in**

China were sitting on a paper loss since that June 12 peak of 6.8 trillion yuan ($1.1 trillion), according to CICC.

Though the crash could mean that there are some bargains out there, it is hardly surprising that **China's turbulent stock markets are drawing fewer new entrants**. The number of investors opening **new accounts** in the week ending July 24 was **down 20% from the corresponding week in June**.

"**Families that haven't invested aren't jumping in**," said Li Gan of China's Southwestern University of Finance and Economics, whose recently released China Household Finance Survey covers 28,000 households. "The market lacks new blood."

Still, some investors do plan a return to stocks.

"Where else can I put my money?" said Helen Lu. "Real estate is so expensive and beyond our reach, and there are no other good investment channels." Yields on bank savings accounts, still the most popular place for Chinese to put their money, are low. So the Shanghai-based medical executive's family put most of their 600,000 yuan in savings in China stocks, only to see the value of their portfolio fall by as much as 60%. Having sold on one of the rebounds, they are now looking to invest again through friends who run funds.

The **Chinese are big savers, setting aside as much as 50% of their disposable income**, according to the World Bank. The **government had hoped to channel some of that from banks to the capital markets**, but for now that hope looks rather forlorn

Debt-Market Tumult Hits Corporate-Bond Sales

by Mike Cherney — Sep. 28, 2015

Three companies reduced or put off planned bond sales in response to soft investor demand.

Westfield Corp., .part owner of the London shopping mall - Left, canceled a sale of 10-year bonds.

Bond-market turmoil mounted Monday, as **three companies reduced or put off planned bond sales in response to soft investor demand, damped by concerns that a global economic slowdown is taking shape**.

Santander Holdings USA Inc., the U.S. arm of Spanish bank Banco Santander SA, canceled a planned sale that had been expected at $1 billion or more, a person familiar with the deal said. Chattanooga, Tenn.-based shopping-center company CBL & Associates Properties Inc. pulled a $300 million bond sale. Westfield Corp. another shopping-center firm, canceled the sale of 10-year bonds, though the company was able to sell $1 billion in five-year debt at higher yields than initially expected.

The market weakness is the latest sign of building worries about the pace of global economic growth. The deals pulled Monday came from companies carrying investment-grade ratings; bankers had little trouble selling similar bonds earlier in the year.

"I have never seen the investment-grade primary markets this schizophrenic before," said Ron Quigley, managing director and head of fixed-income syndicate at Mischler Financial Group. "One day the window is open, the next it's slammed shut."

U.S. corporate-bond issuance in 2015 is up 15% from the comparable year-ago period, according to Securities Industry and Financial Markets Association data, after setting records in each of the past three years.

But the market action over the past month reflects **anxiety among** some **investors** that **slower growth in China** and **persistently low commodity prices will push some companies into financial distress and dim global economic prospects**. **Bond investors in recent months have demanded higher yields relative to Treasurys to own U.S. corporate debt**, indicating some worry about companies' ability to pay back their debt.

"We're starting to become a little more cautious in terms of our views," said Christopher Coolidge, a portfolio manager at Brandywine Global Investment Management, which oversees $65 billion. "We're **OK heading into the end of the year, but next year I think is going to be pretty tough for the U.S. eco**nomy."

Bonds backed by mining giant Glencore PLC dropped sharply after an analyst report from Investec Securities renewed questions about whether the Switzerland-based company will be able to reduce its debt load amid soft commodity prices. The prices of some Glencore bonds fell as much as 25%, a large drop for a company that still commands investment-grade ratings.

"I've never seen bonds react so violently to a research report," said Tim Doubek, senior portfolio manager at Columbia Threadneedle Investments, which oversees about $500 billion.

Hewlett-Packard Co. could represent another test. The company is prepping a sizable bond sale that was expected to sell as early as Monday, some investors and analysts said. H-P could still sell the bonds later in the week.

An H-P spokeswoman declined to comment. Representatives for Westfield and Santander didn't respond to requests for comment.

CBL pulled its bond sale "in light of today's capital-market conditions," the company said in a statement. "We decided to **postpone** the **offering until market conditions become more favorable.**"

Corporate-debt markets had been consistently wide open in recent years, as investors bet that slow but steady economic growth in the U.S. would support corporate earnings.

Monday's events come after companies in the junk-bond market, where companies have lower credit ratings, were **forced** last week to **increase yields on new debt sales**. Altice NV paid higher yields on a bond offering backing its purchase of Cablevision Systems Corp. and had to reduce the size of its deal from $6.3 billion to $4.8 billion. Olin Corp. also **reduced the size of its bond sale and boosted interest payments** to fund its acquisition of Dow Chemical Co.'s chlorine-products unit.

Junk bonds, which are viewed as a more sensitive indicator of economic conditions because the companies are more indebted and have less cushion to withstand a downturn, logged a poor day Monday. The SPDR Barclays High Yield Bond ETF was down about 1.4% on the day, almost as bad as the 1.9% drop in the Dow Jones Industrial Average stock benchmark.

China Shares Wipe Out All Gains This Year

by Chao Deng and Anjuani Trivedi – WSJ – Aug. 24, 2015
Rose Yu and Yifan Xie contributed to this article.

A number of currencies in the region fell to multiyear lows; **China shares finish down 8.5%**

Chinese stocks suffered their worst single-day loss in more than eight years, spurring a fresh phase of a global selloff that dragged the Dow Jones Industrial Average to an 18-month low.

The plunge in China shines an unwelcome spotlight on the country's financial condition just as its leaders are putting on two big events meant to showcase China's global standing.

Chinese government media dubbed it "**Black Monday**," a surprisingly bleak description to come from the People's Daily, which normally tries to cushion bad news. The **Shanghai Composite Index's 8.5% loss was its biggest percentage decline since February 2007**, leaving the market down 0.8% for the year and down 38% from its mid-June peak. At that point, stocks were up 60% for the year, having doubled over the preceding 12 months.

"Compared with the selloff in June and July, when investors still harbored hope of government rescue measures, this time investors are completely despairing, because the previous government stabilization measure have failed," said Amy Lin, analyst at Capital Securities.

Coming on top of a global downturn on Friday, it spurred more selling across Asia, Europe and the U.S. The **Dow Industrials tumbled 588.40 points, or 3.6%,** to 15871.35, the lowest level since February 2014. **Minutes after the open of U.S. trading, the blue-chip index plummeted more than 1,000 points but later pared losses**.

Driving the global selloff is the concern that the once-highflying Chinese economy may be slowing significantly, which has triggered steep losses in global stock markets, commodities and emerging-market currencies. China's surprise currency devaluation two weeks ago – which could make its exports more competitive – and a string of weak data signal the economy may be feebler than expected, despite a campaign to rev up growth that has included interest-rate cuts and measures to boost lending.

The **smaller Shenzhen market fell 7.7%** to 1882.46, putting it down 40% from its June peak. Both indexes have fallen past bottoms hit in early July. In the days leading up to that low point, the government intervened to stem the selling.

Investors were poised for another pounding on Tuesday, with New Zealand's stock market opening 2.3% lower and futures for Australian shares also pointing down.

Mark Lu, 30 years old, said after the government started buying stocks to boost the market, he followed suit. "I have never thought of the plunge," he said. "It totally ran counter to the government's intention."

Mr. Lu said he is planning to load up on more stocks, as he believes the market is nearing the bottom. “I know it sounds like a gamble,” he said. “But sometimes the Chinese market is indeed a casino.”

The decline comes at an embarrassing time for China’s leaders. The government already has shut down parts of central Beijing in preparation for a Sept. 3 parade that will feature about 12,000 troops and nearly 200 aircraft. Marking the 70th anniversary of the end of World War II, it is meant to highlight how far the country has come since then.

The other big event, the world track-and-field championships, serves as a reminder of a recent high point in China. The competition is being held in the stadium known as the Bird’s Nest, built for the 2008 Olympics, when the country was coming off three years of nearly 13% annual growth.

Shanghai’s performance is increasingly a factor for investors in global markets, even though China’s mainland market isn’t yet fully accessible to foreigners.

Stock markets across the region – from Japan to Australia – slid more than 4%, and a number of currencies in the region fell to multiyear lows.

Traders are looking to China’s next easing move after The Wall Street Journal reported that the central bank is preparing to flood the banking system with liquidity to increase lending.

One measure analysts are expecting is a cut to banks’ reserve-ratio requirements, the third such cut in an easing cycle that began last November. Such a move, allowing banks to keep a lower share of their deposits on reserve at the central bank, could potentially free up hundreds of billions of yuan in funds from banks to make loans.

Some 2,153 stocks trading in Shanghai and Shenzhen fell by the 10% daily limit allowed by regulators, according to Wind Information Co. That means at least **two-thirds of mainland shares were effectively un-tradable** – bargain hunters have to wait until at least the next trading day. Among the hardest-hit stocks in China were brokerages. Citic Securities Co., one of China’s biggest, was down by its 10% limit Monday and has fallen more than 50% this year.

The global stock rout hit **India**, which had been one of the best-performing emerging markets in the world. India’s S&P **BSE Sensex fell 5.9%,** its largest one-day percentage drop since January 2009. For the year, the benchmark is down 6.4%, at 25741.56 – its lowest point in 13 months.

Hong Kong’s Hang Seng Index, which last week slipped into bear-market territory – defined as a drop of more than 20% from a recent high – **slid a further 5.2%** to 21251.57. A benchmark of Hong Kong-listed Chinese companies fell below 10000 for the first time in more than a year, finishing off 5.8% at 9602.29.

Hong Kong Financial Secretary John Tsang held a news conference in a bid to calm jitters. “Hong Kong’s financial market is still operating in an orderly manner and in a smooth fashion,” he said.

Japan's Nikkei Stock Average was **down 4.6%,** Australia's S&P ASX 200 was **off 4.1%** and **South Korea's** Kospi was **down 2.5%. Taiwan's** Taiex, Asia's worst-performing stock index this year—down 20%—**fell 4.8%**.

In **currencies**, losses accelerated as nervous investors pulled out cash. The Malaysian ringgit led the way, falling to a fresh 17-year low, while the Thai baht fell to a six-year low and the South Korean won to a four-year low, all when measured **against the U.S. dollar**. Indonesia's rupiah weakened to a multiyear low, while the Philippine peso fell to its weakest in almost five years.

"The global tone towards emerging markets is getting worse, and [investors'] risk aversion is broadening," said Rajeev DeMello, head of Asian fixed income in Singapore at Schroders, which has $487.4 billion under management.

The ringgit spiraled down after Swiss authorities opened a criminal probe into the relationship between "suspicious transactions" in the country's banking sector and state investment fund 1Malaysia Development Bhd. The currency was down 1.5% against the dollar and is down 21% for the year.

Asian bond prices fell relatively modestly, with heavier selling in high-yield corporate debt, including that of Chinese property businesses and Indonesian companies. But if the rout continues, investors could start turning to their more-liquid assets to cover losses or meet margin calls – when brokerages ask borrowers to add more money to their trading accounts or to unwind their bets if the market has fallen below certain thresholds.

"If the stock rout continues, that will create a systemic selloff, as investors will need to raise cash to cover margin calls amid equity falls," said Ben Sy, Asia head of fixed income at J.P. Morgan Private Bank in Hong Kong. "Fixed income is the only area for them to raise cash."

U.S. oil prices tumbled. Futures for West Texas Intermediate fell by 2.8% to **$39.33**, after falling below the $40 mark Friday for the first time since 2009. Brent, the international benchmark, fell 2.4% to $44.35. It is down 23% in 2015. Gold was flat at $1,159.80 a troy ounce, after hitting seven-week highs last week.

Fear Index' Grabs Headlines as Stocks Swing

by Jo Craven McGinty — WSJ — Sep. 18, 2015

Volatility gauge yields clues on how investors are insuring their portfolios

Left Traders monitor the **CBOE Volatility Index**, or '**fear gauge**,' at moments of market turbulence.

When **Robert E. Whaley** settles into his home office, you can count on two things: His television will be tuned to CNBC, and he'll be tracking the stock market's "fear index" on his computer.

Mr. Whaley, a **professor of finance** at **Vanderbilt University**, may not be a household name. But chances are you've heard of the volatility index he designed, known to market watchers as the **VIX**.

The VIX is the **most popular measure of expected short-term volatility on Wall Street**. The index is **computed in real time on trading days**, and **when it shoots up**, it **suggests investors fear market prices are about to move wildly**.

The **historical average of the VIX is around 20**. **Lower numbers signal that investors are confident in the strength of their investments**. **Higher numbers signal investor anxiety**. For example, **during the 2008 financial crisis**, the **index hit** a dizzying **80**, and **last month**, it made news when it **spiked above 50 for the first time since 2009** before returning to near its long-run average.

"What you're scared of is a drop in the value of your pension fund," said Mr. Whaley. "The **higher the VIX gets, the more fear you have the market will drop**."

The VIX reflects investors' sentiment by **tracking how much** they are **paying for** "**out-of-the-money**" **stock options** — **particularly** "**put**" **options**, which provide a **cushion against falling market prices**.

Mr. **Whaley compared it to buying insurance for a beach house**.

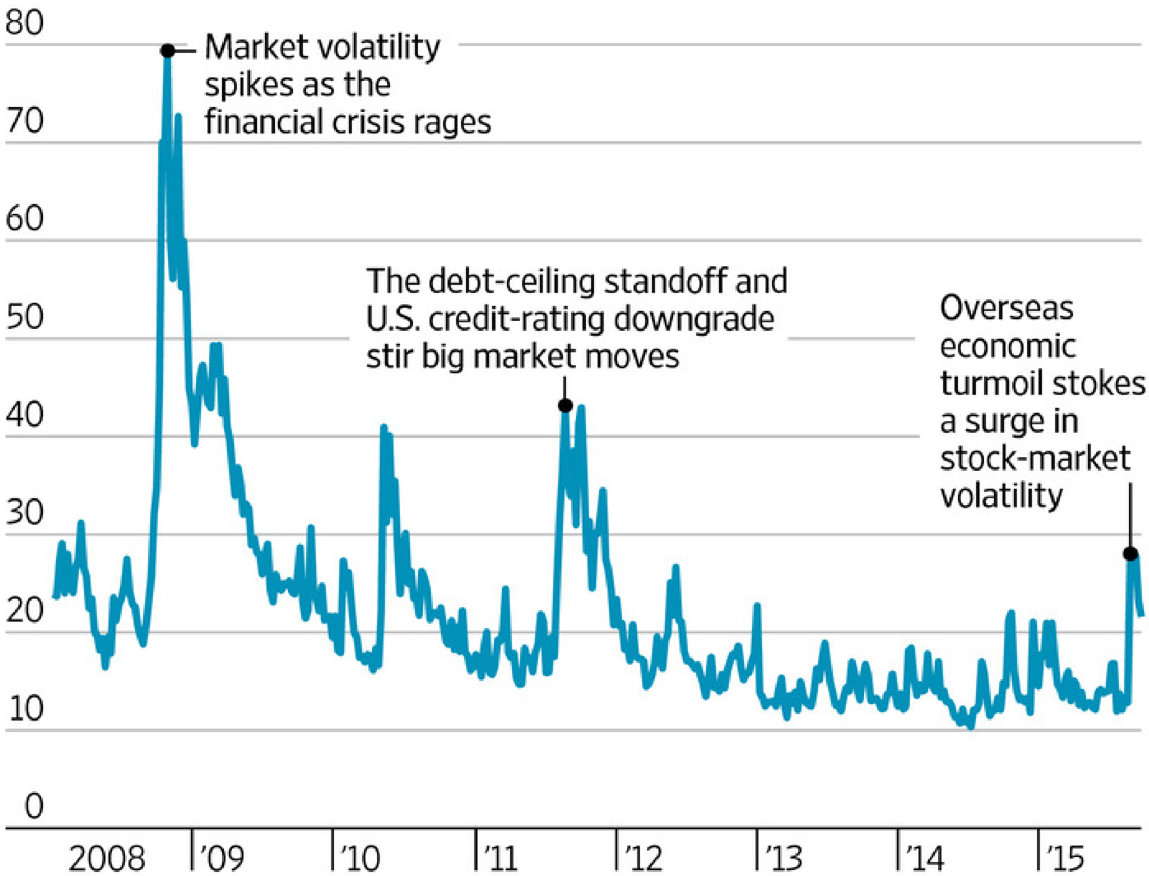
"**If a hurricane is forming and there is potential for the hurricane to hit land in the next few weeks, you are likely to pay a whole lot for insurance**," he said. "You want to protect the value of the home."

If investors fear a storm is brewing in the stock market, they could sell their stock, but with trading fees and other costs that would be expensive. Or they could opt to protect their investment.

View of Volatility

The 'fear index' has traded around a historical average of 20, but it has spiked over the past decade amid bouts of market tumult.

CBOE Market Volatility Index (VIX)



Source: FactSet THE WALL STREET JOURNAL.

"**Instead of selling your stocks, you can go out and buy insurance**, and the insurance you would buy would be **put options on the S&P 500**." Mr. Whaley said.

A "**put**" **option gives someone the right to sell stock at an agreed-upon price by a certain date**. The stock **price specified** in the contract is called the "**strike**" **price**. And **if it is lower than the market value of the underlying stock**, the **options** are "**out of the money**." (A "**call**" option is the **opposite**; it gives someone the **right to buy stock at an agreed-upon price by a certain date**.)

"VIX is driven by the price of out-of-money calls and puts, but the calls don't really matter," Mr. Whaley said. "If you look at **trading activity in the market**, it is **predominantly puts**. You're **only concerned about the downside risk**."

Put options benefit investors in the event that the market price of a stock tumbles below the strike price. If it does, the investor who bought the put will collect the difference between the two values.

For example, suppose the market price of the S&P 500 portfolio was $1,951 per share, and the strike price of a put option was $1,950. If the market price falls below that threshold to, say, $1,945 before the option contract expires, the investor who purchased the put will collect $5 per share. (*This doesn't account for the cost to purchase the put option*.)

If the market price doesn't fall below the strike price before the contract expires, there is no payout.

"If the stock stays above $1,950, you'd have a situation you have with any insurance," Mr. Whaley said. "You pay for it and never collect. You lose the premium. What you bought is the satisfaction that if there had been a drop, you would have been covered."

Options contracts are sold by market makers who accept risk to facilitate trading. The **fees** they charge for the options contracts **offset their own risk of having to pay off investors if the stocks do tank**. **So when nervous investors begin to clamor for puts, market makers raise the price**.

That is what sends the VIX skyward.

"The **more demand, the higher the price, and the higher the prices, the higher the VIX**," Mr. Whaley said.

Investment firms like Zacks notice the VIX, but because they look further into the future, the level of the fear gauge doesn't alter their overall strategy, according to Bryant Sheehy, who is business development director for Zacks.

"It's more of a way to add some sexiness to editorial articles," he said, referring to headline-grabbing shifts in the VIX. "It's one more data point we can mention to talk about a tough market and what opportunities are now coming up.

But **for speculators** — the storm chasers of the stock market — **the VIX serves as a weather vane, pointing out when they should plunge into the market in search of short-term trading profits**.

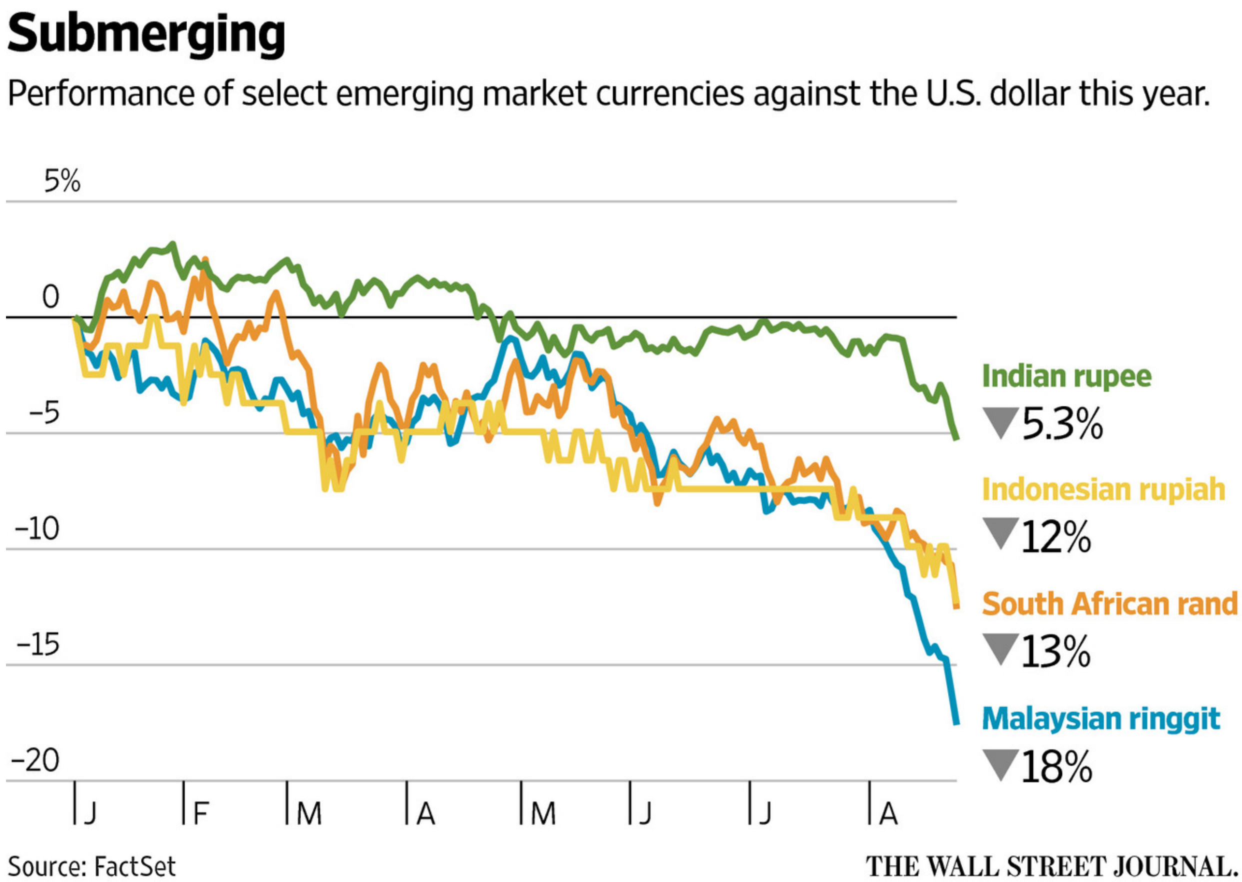
"**Volatility is opportunity**, not risk," said Tim West, who publishes market analysis on tradingview.com, a social network for investors and traders. "Most people get that backwards."

Emerging Markets Hit Hard as Global Rout Continues

by Andrey Ostroukh and Patrick McGroarty – WSJ – Aug. 25, 2015

James Marson, Raymond Zhong, and Jeff Lewis contributed to this article.

Growing anxieties about China cause investors to pull money from developing markets



Bad news from China has sparked a firestorm in the developing countries that feed its vast industrial machine, leaving a swath of economies with few good ways to escape a crunch.

In **Indonesia**, coal once bound for China is piled up in port. In **South Africa**, mines that fed China's voracious demand for metals are firing workers. In financial markets, investors have responded by pulling out.

On Monday, the currencies of **Russia**, Indonesia, South Africa, **Brazil** and other commodity exporters tumbled to multiyear lows against the U.S. dollar. Stock indexes collapsed.

South Africa's mines are among the industries in emerging markets impacted by the slowing of China's economy. Nations such as **Thailand**, Indonesia and **Malaysia** have seen imports decline and their currencies fall.

The Russian ruble hit a seven-month low Monday, and by the end of the main trading session in Moscow it slid to its weakest-ever closing level of 70.9 to the dollar. A year ago, a dollar bought only around 36 rubles.

The weak currencies in these economies present a glum dilemma: Raise rates to defend them, and the economy takes a hit from tighter credit; let them fall, and inflation erodes household budgets. Meanwhile, dollar-denominated debt becomes a bigger burden for many cash-strapped governments and companies.

"We were all fully aware **emerging markets were vulnerable**," said Malcolm Charles, a portfolio manager at Investec Asset Management in Cape Town, which has $120 billion under management. Now, he said, "I can only see red on my screen. There's a complete pricing-out of risk assets."

The blowout in Russia is emblematic of the fragility of economies relying on high raw materials prices supported by China's long-sturdy demand – and of the tight constraints faced by those countries' policy makers.

Chinese woes helped trigger a plunge in the price of Russia's principal export and main source of foreign-currency income, crude oil. That, in turn, has pummeled the ruble.

The weak ruble has pumped **inflation** above 15%, meaning the central bank has little space to cut interest rates further to try to revive the economy, which contracted 4.6% in the second quarter compared with last year.

And Russian authorities have all but given up spending foreign-currency reserves to help support the ruble rate, something the central bank did for years. It let the ruble float freely late last year after spending nearly $80 billion of its reserves in an attempt to prop it up, only to see the ruble weaken substantially. Russia has $363 billion of

Russia is doubly vulnerable because it has turned to China as relations with the West have soured over the past two years. Russia is the second-largest supplier of oil to China, after Saudi Arabia, and Moscow has sought to increase trade and investment ties with China, especially in its big energy projects.

Large chunks of the emerging world have staked their growth on supplying China. "There are piles of coal in ports," said Supriatna Suhala, executive director of the Indonesian Coal Mining Association. Big coal miners, he said, have sent workers home to make ends meet.

In Thailand, a major supplier of rubber to China's tire factories, Perk Lertwangpong, a rubber farmer and former president of the Rubber Planter Cooperatives, said he expects exports to fall by a fifth in 2015 compared with last year.

Indonesia, which sells coal, minerals and palm oil to China, was riding high not long ago. Economic growth in 2012 was around 6%. This year, the stock market is down more than 20%. Its currency, the rupiah, is down 12.5% for the year and is hovering at its lowest level since the Asian financial crisis that began in 1997.

Latin America, too, rode the coattails of surging Chinese demand for commodities like soybeans, copper and iron ore during the past 15 years. The peso currencies in both oil-exporting Mexico and Colombia hit record lows on Monday. **Mexico's peso** is **down 23% in the past year**, **Colombia's** is **off** an eye-popping **60%,** and **Brazil's real** has **plunged** nearly **36%**.

Revenue at Rio de Janeiro-based Vale SA, the world's biggest iron-ore producer, fell 29.7% in the second quarter from a year earlier as weaker demand from China pushed the price of the commodity lower. China is Vale's – and Brazil's – biggest customer. The mining company has been selling off noncore assets, including four giant ore-carrying ships, as it tries to shore up its finances.

In South Africa, the rand on Monday plummeted to all-time lows of beyond 14 to the dollar. Inflation is rising. Economists warn growth could miss already-lackluster forecasts, leading to a second consecutive sub-2% expansion this year.

Yet South Africa's central bank raised rates last month to bolster its currency despite economic distress. The bank said Monday that if the rand plunges more aggressively, it would "consider becoming involved in foreign exchange markets to ensure orderly market conditions."

Hardest hit are the gold, platinum and iron mines whose riches built South Africa into the continent's most developed economy. B eijing's demand for those metals pushed China past the U.S. as South Africa's top trading partner in 2009.

The reversal since then has been severe. AngloGold Ashanti Ltd. last week reported a loss of $142 million in the second quarter. Platinum miner Lonmin PLC said it would cut 6,000 jobs, nearly a fifth of its workforce, through 2017. Glencore PLC is cutting 380 jobs at a South African coal mine.

"There's a big crunch," said Anton van der Merwe, a director at I-Cat Environmental Solutions, a contractor that services roads and purifies water at some of South Africa's biggest mines.

As miners have laid off workers and trimmed costs, I-Cat has pursued new clients, such as telecoms. The closely held company is still making money, Mr. van der Merwe said. But profits were a fifth lower than expected in the first half of its current fiscal year.

"At the end of the day, it's affecting everybody," he said of the turmoil emanating from China.

The weak currencies have a silver lining, especially for those countries with more-dynamic manufacturing sectors: exports. From Mexican-made cars to Colombian-grown flowers, exports from Latin America are becoming far cheaper in dollar terms and will gain competitiveness. That is especially important to Mexico, a rival to China in their mano-a-mano battle for a share of the U.S. import market.

Indonesian Trade Minister Tom Lembong said straitened circumstances could aid the country's efforts to become less resource-reliant. "Short term, we have to let the market do its work," Mr. Lembong said. "The depreciation of the rupiah has already done what it's supposed to do. We've swung from at least four years of trade deficits to, this year, a trade surplus."

In Russia, the weakening of the ruble in line with the oil price is protecting the federal budget from severe strains. Russia gets around half its federal budget revenues from oil and gas sales. Chris Weafer, senior partner at Macro-Advisory, a Moscow-based consultancy, said the weaker ruble will cause consumers and businesses to postpone investment and spending decisions, worsening the outlook for the economy of the next six months. But, he said, longer-term the decision to let the ruble weaken could help boost growth. Russians have reacted calmly to the renewed ruble weakness, a contrast to the currency's shock collapse in December, which set off panic buying of dollars and durable goods. President Vladimir Putin remains widely popular despite the hit of inflation to household budgets

Banks reported no unusual increase in foreign-currency sales beyond the usual demand of the holiday season. M. Video, a leading electronics retailer, said it had seen no increase in sales. "We just stopped caring," said Natalia Muravyova, a 30-year-old telecommunications consultant. "There's a feeling that you can't do anything anymore, that nothing depends on you. So you sort of watch from the distance."

Ms. Muravyova said she had long given up holidays with her husband and child to Europe, and instead went to Crimea.

More Utility Losses Won't Be a Shocker

by Spencer Jakab – WSJ – Jun 25, 2015

Utilities have slumped this year as bond yields have risen; more carnage is likely. Utilities stocks as a group are down nearly 12% so far this year.

Left – Transmission lines from NRG Energy's Joliet Station power plant in Illinois.

A traditional preserve of widows and orphans became a widow maker this year.

Utilities stocks as a group **have dropped by nearly 12%** as the year's halfway mark looms. The culprit isn't some hostile rate regulator or even bad weather – it's the bond market's reaction to what the Federal Reserve might do later in 2015.

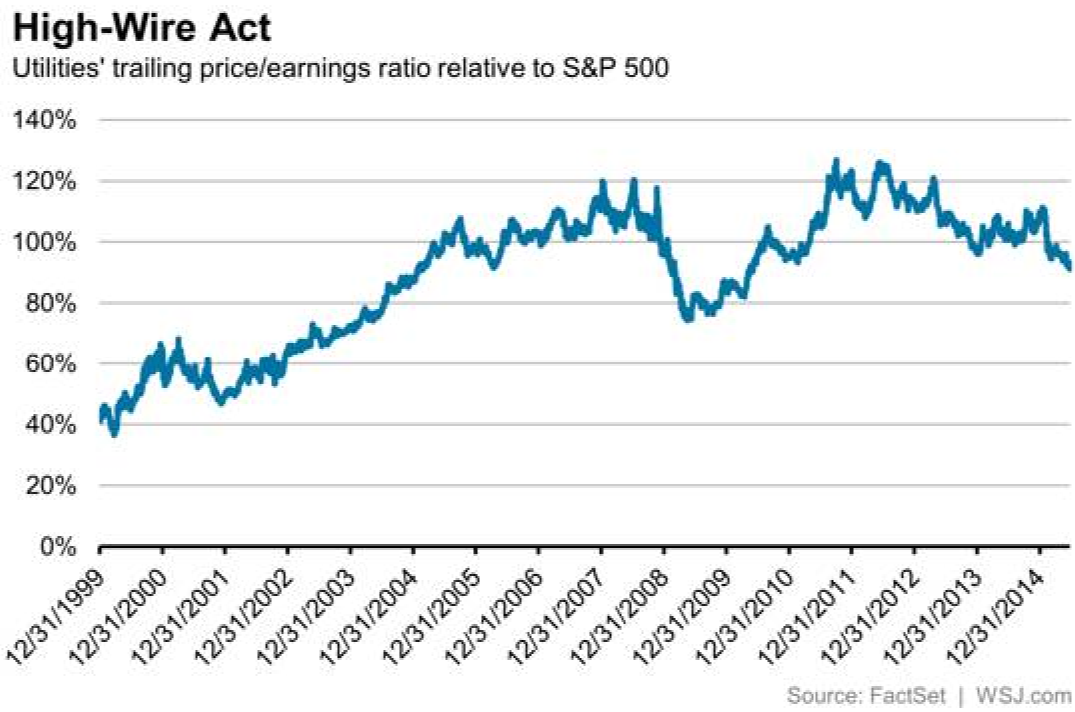
Investors craving regular income have long looked to regulated utilities as a source of dependable quarterly checks. **Six-plus years into the era of near-zero interest rates**, they have been **more appealing than usual**. At the **end of 2006**, a **popular exchange-traded fund tracking the sector**, the **Utilities Select SPDR Fund**, had a **dividend yield of 4.1%**. That was **lower than the 4.7% offered at the time by the benchmark 10-year Treasury note, but wasn't unusual**. Utilities payouts can keep up with inflation.

Fast forward to the **end of last year**, and the **utility ETF's yield was** less attractive than before. But at **3.2%,** it **handily eclipsed the Treasury note's yield of 1.9%.**

For the sector, though, that was the end of a good run that most strategists earlier said wouldn't continue in **2014**. **Bets that utilities stocks would fall surged at the start of 2014, as most economists predicted a rise in bond yields, making bond-like stocks unattractive**. **Instead yields went the other direction and the utility fund outpaced the S&P 500 by 13 percentage points**.

That was quite the contrast to the prior year. Between April and August 2013, the time of the bond market's so-called **taper tantrum**, the utilities ETF lagged behind the market by the same amount.

(Continued on next page)



One reason utilities are so choppy lately is a concept called **duration**, a measure of **how sensitive prices are to moves in interest rates**. The **longer the duration**, the **more a bond's price moves**. **<u>Utilities stocks have a theoretical duration of about 23 years</u>**. **A leading bond index, meanwhile, has a duration of five years**.

And the carnage may not be over. **Utilities stocks' price/earnings ratio relative to the S&P 500 has dropped to around 91% today, from about 107% at the start of the year. But that remains well above the 73% average seen between 2000 and 2006**.

That still leaves utilities looking overcharged as rate increases draw closer.

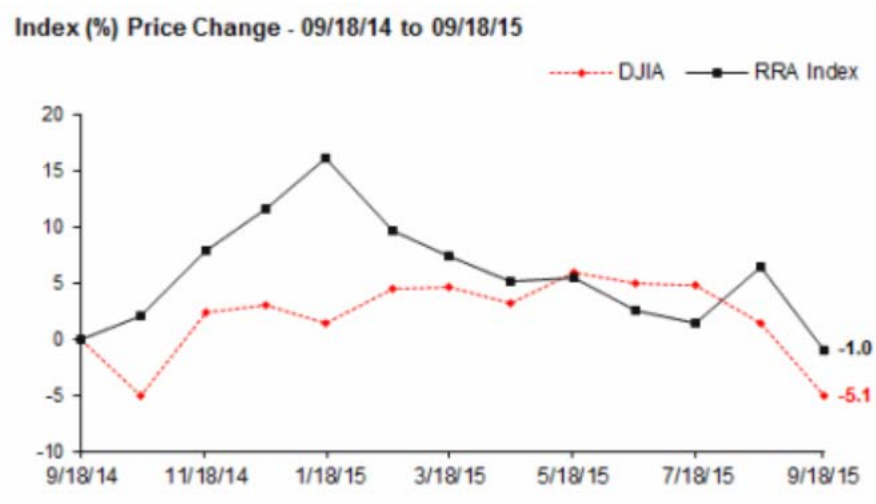
Utilities Regain Favor,

Broad Markets Withdraw as Fed Postpones Rate Move

by Brian Collins — Regulatory Research Associates (RRA)

An affiliate of SNL Financial LC — Sep. 21, 2015

Regulatory Research Associates (RRA), an affiliate of SNL Energy, noted in a recent Financial Focus research report that most broad market indices suffered, while utilities were resurgent, as **investors sailed for safe harbor** with the Fed voting down a September rate action. RRA indicated that while the Fed may be attempting to stabilize markets, investor anxiety around a potential global slowdown and U.S. economic fallout was compounded by the Fed's rate restraint. The RRA Utility Index was up 2.5%, as the DJIA and S&P 500 fell 0.3% and 0.2%, respectively; the NASDAQ held onto a 0.1% increase for the week. Thus far in 2015, the RRA Index, DJIA, and S&P 500 are down 12.1%, 8.1%, and 4.9%, respectively, while the NASDAQ is up 1.9%. Over the previous 12 months, the RRA Index was down 1%, while the other indices we track were mixed, with performance within a range of -5% to +5%



Source: SNL Energy

Index Performance	Price Change through 09/18/15 (%)		
	Week	Year-to-Date	Last 12 mos.
RRA	2.5	-12.1	-1.0
DJIA	-0.3	-8.1	-5.1
S&P 500	-0.2	-4.9	-2.7
NASDAQ Composite	0.1	1.9	5.1
Source: SNL Energy			

Wall Street Says Fed's Rate Decision is Good for Utilities

by Darren Sweeney — SNL Financial LC — Sep 18, 2015
Rycia Mantua contributed to this article.

After much debate and concern in the power and electric utility industry about whether the Federal Reserve will raise interest rates for the first time in nine years, the Federal Open Market Committee on Sept. 17 said it was leaving the federal funds rate unchanged. Wall Street, for the most part, agrees this is good for the sector.

"Given the interest-rate sensitivity of electric utility stocks, we regard the Fed's inaction as a positive for the sector, although renewed uncertainty regarding a rate hike is likely to occur as we get later in the year," BMO Capital Markets Corp. analyst Michael Worms wrote in a Sept. 18 research flash.

In response to the decision, BMO reiterated its "outperform" ratings on American Electric Power Co. Inc., Calpine Corp., Duke Energy Corp., Edison International and NextEra Energy Inc.

Edison International's stock led utility and power equities Sept. 17, according to data compiled by SNL Energy. The company's stock closed at $61.10 on Sept. 17, up 2.33% from a $59.71 close on Sept. 16.

KeyBanc Capital Markets Inc. agreed that the **Fed's stance is "supportive of well-positioned utilities."**

"We continue to believe well-positioned utilities offer near-term outperformance potential during what we expect to be a period of monetary policy patience," analyst Paul Ridzon wrote in a Sept. 18 research report.

Top 10 power stock performances for Sept. 17

Company (ticker)	Close ($) 9/16/2015	Close ($) 9/17/2015	Change (%)
Edison International (EIX)	59.71	61.10	2.33
American Electric Power Co. Inc. (AEP)	54.63	55.87	2.27
Talen Energy Corp. (TLN)	12.91	13.19	2.17
Ameren Corp. (AEE)	39.69	40.54	2.14
Eversource Energy (ES)	46.71	47.66	2.03
El Paso Electric Co. (EE)	34.96	35.65	1.97
Abengoa Yield Plc (ABY)	21.61	22.01	1.85
TerraForm Power Inc. (TERP)	35.02	35.64	1.77
Unitil Corp. (UTL)	17.19	17.48	1.69
NiSource Inc. (NI)	33.23	33.79	1.69

Data compiled Sept. 17, 2015.
Includes power companies in SNL Energy's coverage universe trading on U.S. exchanges.
Source: SNL Energy

KeyBanc said it is maintaining its view that the initial interest rate hike will likely be pushed into 2016.

In addition to AEP and NextEra Energy, **KeyBanc lists its well-positioned utilities as** ALLETE Inc., CMS Energy Corp., DTE Energy Co., **MDU** Resources Group Inc., NiSource Inc., **Portland General Electric** Co., Pepco Holdings Inc. and Sempra Energy.

At least one industry executive had hoped that the Fed would go ahead and raise the interest rate.

During a panel discussion Sept. 16 at the Bank of America Merrill Lynch 2015 Power & Gas Leaders Conference in Boston, Dominion Resources Inc. Executive Vice President and CFO Mark McGettrick said he hoped the Fed would "go ahead and do it because it's been dragging on and dragging on."

"The overhang — whether it be on the yieldco or MLP or utility sector — up and down, it's been going on for a year now. So, let's go ahead and get it done," McGettrick said.

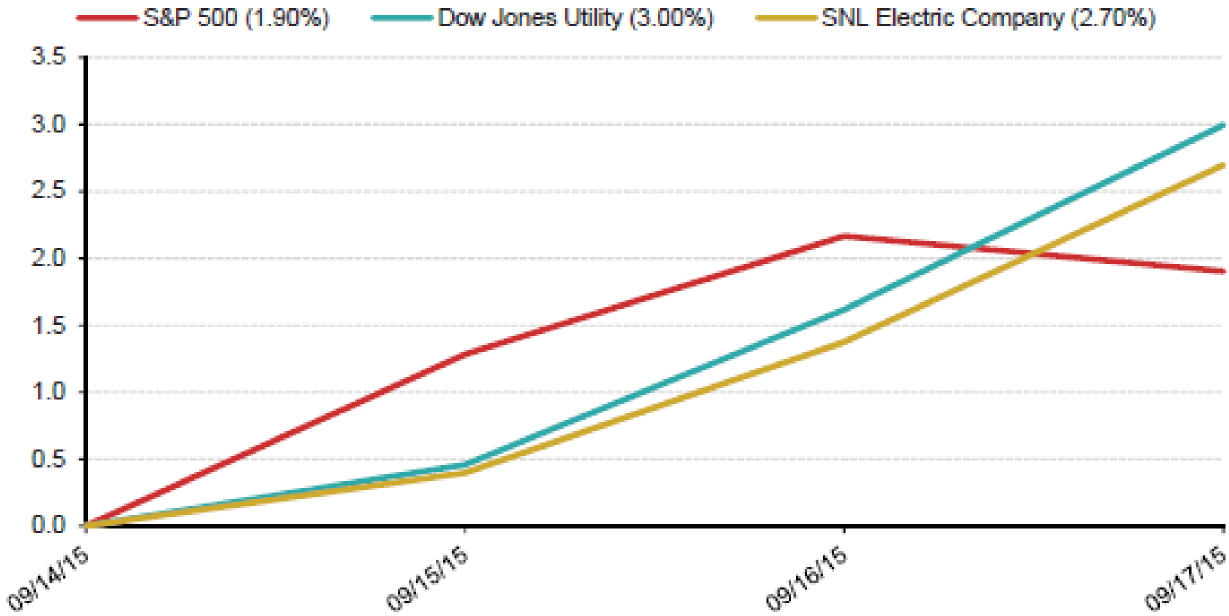
Both McGettrick and NextEra Energy Chairman, President and CEO James Robo said their companies were poised to weather the hike, which was anticipated to be as much as 25 basis points.

Robo noted that NextEra's yieldco vehicle, NextEra Energy Partners, would actually be "less sensitive" to interest rates than the parent company.

"I think whether [the Fed] raises rates 25 basis points isn't going to matter much for the physical economy," Robo added.

McGettrick made similar comments when comparing the impact of an interest rate hike to Dominion's MLP, Dominion Midstream Partners LP.

Select energy index performance Sept. 14-17



Data compiled Sept. 17, 2015.
SNL electric company index includes all publicly traded (NYSE, NYSE MKT, NASDAQ, OTC) electric utilities and transmission only companies in SNL's coverage universe.
Source: SNL Energy

"I just can't believe that interest rates in the environment we're in today are going to have any significant downside compared to what we've seen already with the commodity sensitivity that's out there in just a general MLP, yieldco space," he said. "I think companies … that have strong sponsors, have strong balance sheets, can ride through any of the interest rate sensitivities that might be out there and have the longevity with the assets they have to grow in a number of different ways that a lot of our other competitors don't have."

KeyBanc Capital Markets Inc. Managing Director Andy Redinger said Sept. 16 at the Solar Power International conference in Anaheim, Calif., that yieldcos will be "least affected" by an interest rate hike.

"If you're a yield investor, this is where you'll want to be," he said.

Guggenheim Securities LLC analyst Shahriar Pourreza wrote in a Sept. 16 report that he believes the anticipated rate increase caused the utility sell-off between February and July of this year and said a rate increase "should remove a material technical overhang on the sector."

Moody's, in a Sept. 16 report, said higher interest rates result in higher borrowing costs for the utility industry, which is a credit negative.

"Unregulated utilities are most vulnerable to rising interest rates since they must recoup costs via the market," Moody's said in a news release announcing the report's release. "Regulated utilities can recover interest costs by passing additional costs through to customers, but require regulatory approval before doing so. Public power companies are the least vulnerable, owing to their ability to raise rates without regulatory approval."

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 211

Frequency of General Rate Case Filings by U.S. Investor Owned Regulated Gas Utilities

Exhibits in Support of Opening Testimony

October 16, 2015

Frequency of General Rate Cases by Investor Owned Regulated Utilities

#	Abbreviated Gas Utility	Ticker	Y Indicates a General Rate Case in that Year																Peers	
			2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	UG 288 AVA	UG 288 Staff
A	**Avista**	AVA																	No	No
	Avista (WA)									Y		Y	Y	Y						
	Avista (OR)					Y						Y	Y			Y	Y	Y		
	Avista (ID)		Y	Y			Y				Y	Y	Y	Y	Y					
B	**Cascade**	MDU																	No	No
	Cascade (WA)								Y											
	Cascade (OR)													Y				Y		
1	**AGL**	GAS																	Yes	Sensitivity
	AGL (GA)						Y													
	Chattanooga Gas (TN)											Y								
	Elizabethtown Gas (NJ)																			
	Elkton Gas (MD)									Y										
	Florida City Gas (FL)																			
	Nicor Gas (IL)						Y				Y									
	Virginia Nat Gas (VA)							Y						Y						
2	**Atmos**	ATO																	Yes	No
	Atmos (CO)											Y				Y	Y	Y		
	Atmos (KS)					Y				Y			Y		Y					
	Atmos (KY) / Mid-States								Y			Y				Y				
	Atmos (LA)																			
	Atmos (MS)																			
	Atmos (TX)													Y						
	Atmos (TN)											Y			Y					
	Atmos (VA)						Y				Y	Y					Y			
3	**Laclede**	LG																	Yes	No
	Alagasco (AL)																			
	Laclede Gas (MO)							Y		Y		Y			Y					
	Missouri Gas Energy (MO)															Y				
4	**New Jersey Nat Gas Co**	NJR								Y		Y			Y				Yes	No
5	**NiSource**	NI																	Yes	No
	Columbia (KY)				Y					Y		Y				Y				
	Columbia (MD)										Y		Y			Y		Y		
	Columbia MA)							Y				Y			Y	Y				
	Columbia (PA)										Y		Y		Y					
	Columbia (OH)																			
	Columbia (VA)												Y							
	NIPSCO (IN)												Y							
6	**Northwest Natural**	NWN																	Yes	Yes
	NWN (OR)				Y									Y						
	NWN (WA)		Y			Y					Y									
7	**Piedmont**	PNY																	Yes	Yes
	Piedmont Nat Gas (NC)		Y		Y												Y			
	Piedmont Nat Gas (SC)				Y															
	Piedmont Nat Gas (TN)					Y								Y						
8	**South Jersey**	SJI				Y								Y		Y			Yes	No
9	**Southwest Gas**	SWX																	Yes	No
	SW Gas (AZ)		Y				Y			Y			Y							
	SW Gas (CA)				Y					Y					Y					
	SW Gas (NV)						Y					Y			Y					
10	**UGI**	UGI																	No	No
	UGI Utility (PA)																			
	UGI Penn Nat Gas (PA)											Y								
	UGI Central Penn (PA)										Y									
	UGI Central Penn (MD)																			
11	**WGL**	WGL																	Yes	No
	Wa Gas/Light Co (DC)			Y		Y								Y						
	Wa Gas/Light Co (MD)		Y							Y				Y						
	Wa Gas/Light Co (VA)								Y				Y							

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 212

SNL Overview of Energy Utility Rate Case ROEs 2015 Midyear Update

Exhibits in Support of Opening Testimony

October 16, 2015

STAFF EXHIBIT 212

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

CASE: UG 288
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 213

AVISTA Investor Presentation
Second Quarter 2015 Earnings Webcast

Exhibits in Support
of Opening Testimony

October 16, 2015

Welcome

Second Quarter 2015 Earnings Webcast

August 5, 2015

Call Participants

Scott Morris
Chairman, President and CEO

Mark Thies
Sr. VP and CFO

Dennis Vermillion
Sr. VP, Avista Corp.
President, Avista Utilities

Kelly Norwood
VP, State and Federal Regulation

Christy Burmeister-Smith
VP, Controller and Principal Accounting Officer

Forward-Looking Statements

This presentation 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 our Annual Report on Form 10-K for the year ended Dec. 31, 2014 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2015. The forward-looking statements contained in this presentation 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 risks, uncertainties and other 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.

Net Income (Loss) and Diluted EPS

($ in thousands, except per-share data)	Q2 2015	Q2 2014	YTD 2015	YTD 2014
Operating Revenues (continuing operations)	$337,332	$312,580	$783,822	$759,158
Income from Operations (continuing operations)	$57,360	$62,731	$146,935	$153,073
Net Income from continuing operations attributable to Avista Corp. Shareholders	$25,050	$31,254	$71,499	$78,730
Net Income from discontinued operations attributable to Avista Corp. Shareholders	$196	$69,617	$196	$70,640
Total Net Income attributable to Avista Corp. Shareholders	**$25,246**	**$100,871**	**$71,695**	**$149,370**
Net Income (Loss) per diluted share by Business Segment attributable to Avista Corp. Shareholders				
Avista Utilities	$24,478	$26,685	$68,862	$74,681
Alaska Electric Light and Power Company	$925	—	$3,559	—
Ecova (discontinued operations)	$196	$69,696	$196	$70,807
Other	$(353)	$4,490	$(922)	$3,882
Earnings (Loss) per diluted share by Business Segment attributable to Avista Corp. Shareholders				
Avista Utilities	$0.39	$0.44	$1.10	$1.24
Alaska Electric Light and Power Company	$0.02	—	$0.06	—
Ecova (discontinued operations)	—	$1.15	—	$1.17
Other	$(0.01)	$0.08	$(0.02)	$0.07
Total Earnings per diluted share attributable to Avista Corp. Shareholders	**$0.40**	**$1.67**	**$1.14**	**$2.48**
Earnings per diluted share from continuing operations	$0.40	$0.52	$1.14	$1.31
Earnings per diluted share from discontinued operations	—	$1.15	—	$1.17
Total Earnings per diluted share attributable to Avista Corp. Shareholders	**$0.40**	**$1.67**	**$1.14**	**$2.48**

Driving effective regulatory outcomes

Continued recovery of costs and capital investments

Washington

- May 4, 2015, filed a partial settlement agreement on cost of capital, net power supply costs and rate spread and rate design. Cost of capital based on 48.5% equity ratio and 9.5% return on equity.
- Original electric and natural gas revenue increase request filed Feb. 9, 2015, was reduced from $33.2 million to $17.0 million, and from $12.0 million to $11.3 million, respectively. Agreement included $12.4 million reduction to net power supply costs.
- Unsettled issues include capital investments and recovery of increased utility operating costs.

Oregon

- May 1, 2015, filed a general rate case designed to increase natural gas revenues by $8.6 million.
- Request based on 50% equity ratio and 9.9% return on equity.
- Approved revenue increase of $5.0 million took effect April 16, 2015, following approval of the all-party settlement agreement April 9, 2015. New rates based on 51% equity ratio and 9.5% return on equity.

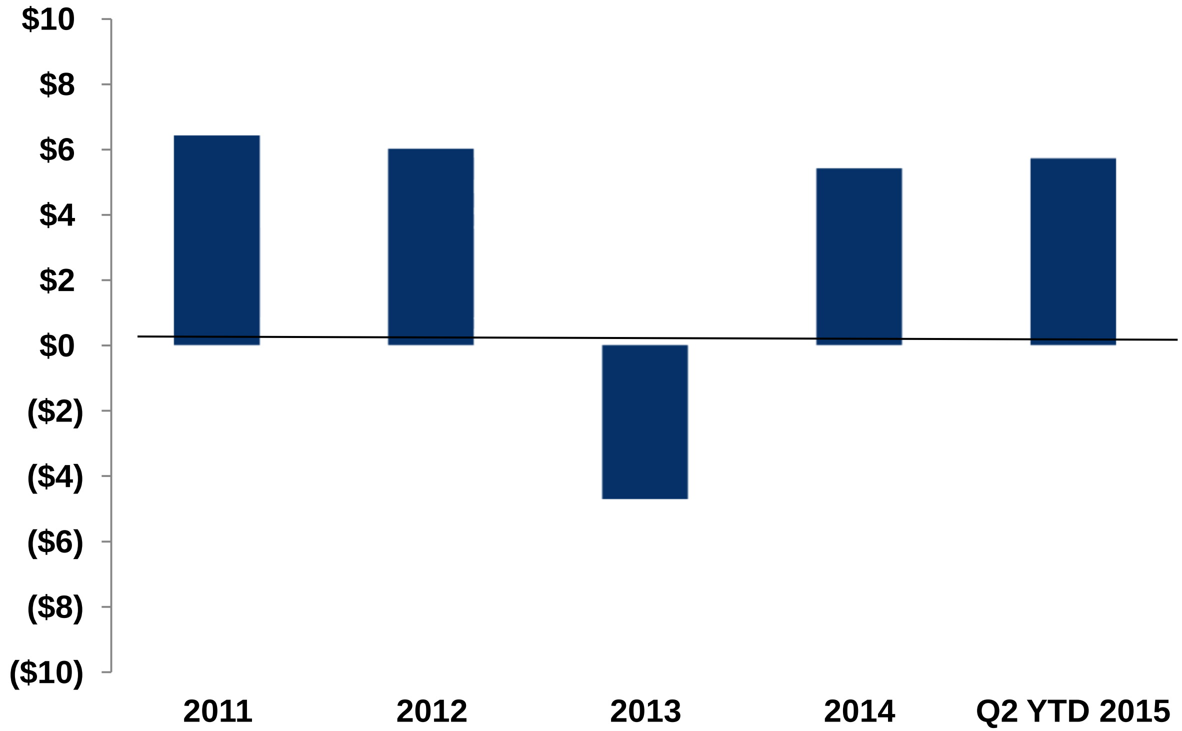
Idaho

- Filed a two-year electric and natural gas rate request on June 1, 2015.
- Request designed to increase annual electric revenues by $13.2 million and annual natural gas revenues by $3.2 million, effective Jan. 1, 2016.
- The request is also designed to increase annual electric revenues by $13.7 million and annual natural gas revenues by $1.7 million, effective Jan. 1, 2017.
- Request based on 50% equity ratio and 9.9% return on equity.

Washington Electric Energy Recovery Mechanism (ERM)

Annual Benefit/(Expense) to Avista

($ millions)



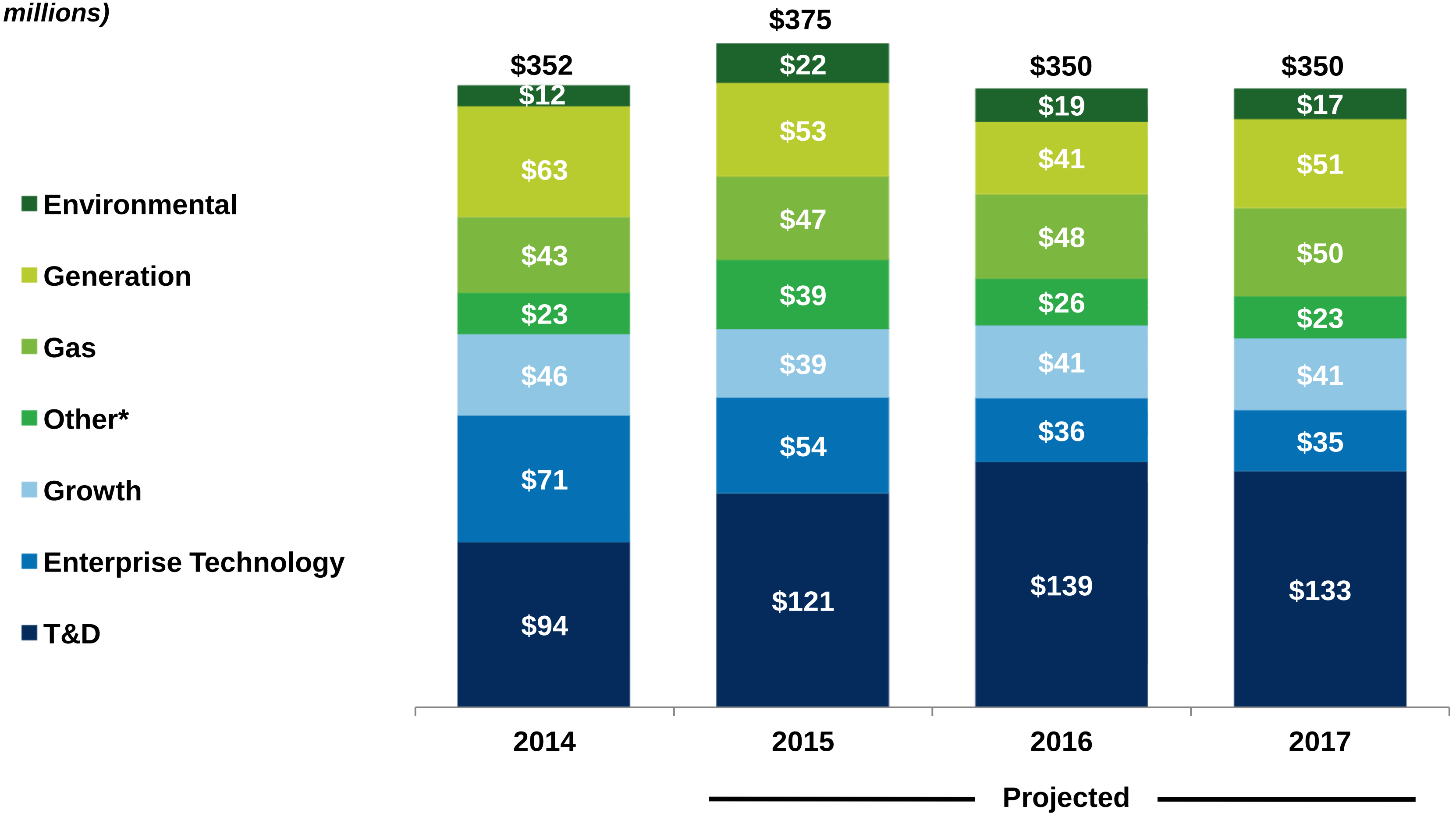
Power supply costs above or below the level in retail rates

$0 +/- $4 Million	100% Company
$4-$10 Million Expense	50% Company
$4-$10 Million Benefit	25% Company
> +/- $10 Million	10% Company

Significant investments to upgrade all systems

5% to 6% rate base growth

Avista Utilities Capital Expenditures**
($ millions)



* Other includes Facilities and Fleet

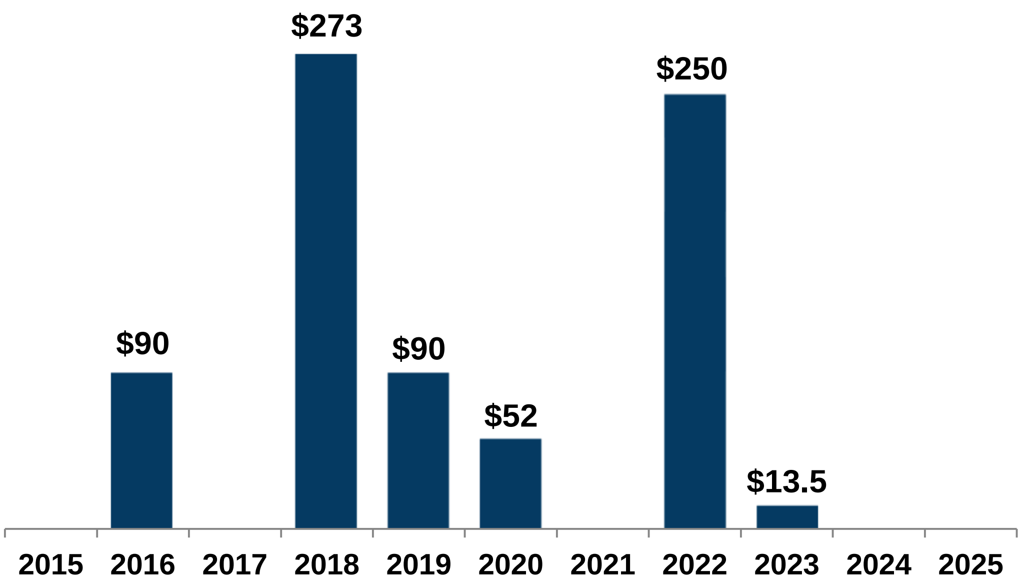
** Excludes planned capital expenditures at AEL&P of $15 million in 2015, 2016 and 2017

Prudent balance sheet and liquidity

$275.6 million of available liquidity at Avista Corp. as of June 30, 2015

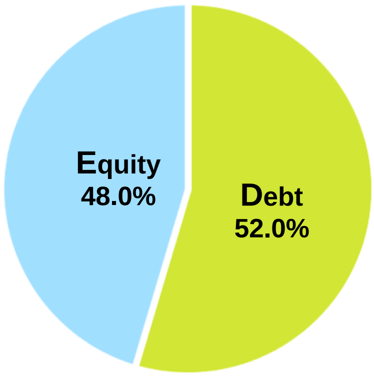
- We expect to issue up to $125 million of long-term debt at Avista Corp. in 2015
- We do not expect to issue any equity in 2015, other than small amounts under the employee benefit plans

No significant maturities until 2018
($ millions)



Additional long-term debt maturities beyond 2025 not shown

Consolidated Capital Structure
June 30, 2015



Growth for 2015

2015 Earnings Guidance	
Avista Utilities	$1.81 - $1.95
AEL&P	$0.08 - $0.12
Other	$(0.03) - $(0.01)
Consolidated	**$1.86 - $2.06**

Guidance Assumptions

- Our outlook for Avista Utilities assumes, among other variables, normal precipitation and temperatures for the remainder of the year and includes the expected impact from decoupling in Washington. Also, for Avista Utilities we are estimating that we will have a provision for earnings sharing for our Washington electric operations and our Idaho operations.
- For Avista Utilities we are expecting below normal hydroelectric generation for the third quarter and normal hydroelectric generation for the fourth quarter of the year. Due to the strong generation through April, we are expecting hydroelectric generation to be about 94% of normal for the full year. Due to significantly warmer weather and reduced heating loads in the first quarter of 2015, we expect a reduction to annual consolidated earnings of approximately $0.08 per diluted share.
- Our outlook for AEL&P assumes, among other variables, normal precipitation, temperatures and hydroelectric generation for the remainder of the year.
- Our guidance range for Avista Utilities encompasses expected variability in power supply costs and the application of the ERM to that power supply cost variability.
- The midpoint of our guidance range for Avista Utilities does not include any benefit or expense under the ERM. In 2015, we expect to be in a benefit position under the ERM within the 90% customer/10% company sharing band, which is expected to add approximately $0.06 per diluted share.
- In addition, because we did not reach the targeted level of repurchases for our stock repurchase programs, we expect earnings dilution of approximately $0.03 per diluted share in 2015.

Questions?

Kettle Falls Generating Station

Contact Information

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Media	Jessie Wuerst Sr. Communications Manager (509) 495-8578 jessie.wuerst@avistacorp.com

Replay	Available at Passcode	(888) 843-7419 40193445#
Webcast	Archived on www.avistacorp.com	

CASE: UG 288
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Information Technology, Distribution O&M

Opening Testimony

October 16, 2015

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

A. My name is Judy Johnson. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to justify my adjustments to Information Technology Plant and Distribution O&M.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared Exhibit Staff/ 301, consisting of one page showing my witness qualifications. I also prepared Exhibit Staff/302, consisting of two pages, Confidential Exhibit Staff/303, consisting of two pages, Exhibit Staff/304, consisting of five pages, and Confidential Exhibit Staff/305, consisting of two pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, INFORMATION TECHNOLOGY PLANT

Q. Were you aware that Avista had been working on a technology project called Project Compass?

A. Yes. The Company has been working on Project Compass for several years. It went into service in February of 2015.

Q. Have you reviewed this project in prior cases?

A. Yes, Staff has looked at this project in the prior two Avista rate cases (i.e. UG 246 and UG 284).

Q. Do you believe that Project Compass is necessary?

A. Yes. Avista's computer systems were old, outdated, and needed to be up-graded.

Q. What is in the Company's filing for Project Compass?

A. Avista's filing contains only one reference to the dollars associated with Project Compass. The reference is in Avista/600, Schuh/13, where she states that "Expenditure Request" (ER) 5138 contains $8.3 million for 2015. It is impossible to tell by Schuh's testimony exactly how much is in the Company's filing for Project Compass. However, Avista's response to Staff Data Request 264 contains Avista's Total System cost for Project Compass (see Exhibit Staff/302).

Q. Are you proposing an adjustment in this case for Project Compass?

A. Yes, based on Avista's response to Staff Data Requests 264 and confidential response to 265C, which are shown in Exhibit Staff/302 and Confidential Exhibit Staff/303.

Q. Please explain your proposed adjustment for Project Compass.

A. Staff reviewed the Washington Utilities and Transportation Commission's (WUTC) Staff testimony (Docket UE-150204/UG-150205, Testimony of David C. Gomez, pages 52-56) (see Exhibit Staff/304) on Project Compass. In his testimony, WUTC witness Gomez states that he determined Project Compass had gone over its budget. Staff then asked the Company questions about the budget overruns in Staff Data Request 264 (Exhibit Staff/302). The Company's response provided Total System numbers. However, Avista also gave Oregon's allocation percentage for Project Compass of 8.072 percent and from this Staff was able to calculate that the Company had exceeded its budget by 34 percent or $27 million on a Total System basis. Staff used the information provided as part of Staff Data Request 302 to calculate the cost overruns and used the Oregon allocation percentage to calculate how much of the overrun was allocated to Oregon.

Q. Do you consider a $27 million cost overrun for Project Compass to be an excessive amount? Please explain your answer.

A. Yes, Staff considers that to be an excessive cost overrun amount for this project. While computer costs are well known to spiral out of control, Staff believes Avista should have had better cost controls in place that would have kept the cost overruns to a minimum. The testimony of WUTC witness Gomez sets forth extensive discussion regarding one of the contractor's, EP2M/Five Point/Ernst & Young, performance of its obligations under the contract (*See* Staff/304, pages 52 and 53 showing Docket UE-150204/UG-150205, Testimony of David C. Gomez, pages 52-53). Staff examined Mr. Gomez's concerns that Avista failed "to recognize, evaluate, identify, document and mitigate the possible risks to Project Compass resulting from the apparent conflict of interest arising from Five Point's acquisition of EP2M less than six months after award of a contract" and "the Company's lack of documentation of the prudence of its decision, above alternatives, to enter into an Extension Agreement with Ernst & Young for the added resources needed to complete Project Compass". After evaluating and considering the WUTC witness's testimony, Staff concluded that Avista had contributed to the cost overruns of Project Compass and should be held partially responsible.

Staff, therefore, has removed $1.175 million in rate base which represents one-half of Oregon's share of the cost overruns. Staff chose one-half because Avista should be held partially responsible for the project's sizable cost overrun and a 50 percent adjustment equally shares the overrun costs between the Company and its customers.

Q. Do you have additional concerns about the costs associated with Project Compass? If so, please explain your answer.

A. Staff discovered that bonuses were given to employees involved in Project Compass. At a minimum, Staff would propose removing 50 percent of the bonuses under the Commission's standard for allowance of bonuses in a rate case. However, Staff decided to remove the Company's total share of the bonuses associated with this project on an Oregon allocated basis, which amounts to $0.068 million. Staff does not believe that when a project has cost overruns of 34 percent it is prudent to give out bonuses. Staff's total adjustment is $1.234 million.

Q. Did you make a similar adjustment in prior cases?

A. No. Staff only learned of the cost overruns in this case and has proposed an adjustment to hold the Company partially responsible.

ISSUE 2, DISTRIBUTION O&M

Q. Why is Staff making an adjustment to Distribution O&M costs?

A. Staff recently discovered through Data Request 262 (Confidential Staff Exhibit/305) that Avista had gone through a Reduction in Force (RIF) in 2013 without notifying Oregon Staff ahead of time.

Q. Why is the RIF an issue?

A. When a company institutes a RIF, there are two things that will happen. The first is that, depending on how many employees are involved in the RIF, labor expenses for the company should be permanently decreased. The second is that there are costs associated with the RIF that the company expects to collect from customers.

Q. Were these the same circumstances for Avista's 2013 RIF?

A. There is no way to tell for sure. Avista's RIF occurred in 2013 and subsequently Avista has filed two general rate cases (UG 246 and UG 284) for an increase in rates. The Company did not inform Oregon Staff at the time either case was filed that a RIF had occurred. That information should have been in the Company's UG 246 testimony and it was not. Avista could also have verbally informed the Oregon Staff about the RIF, but again it appears Avista did not do so.

Q. What is Staff's concern in the current case that involves a past RIF?

A. Staff asked Avista in Data Request 262 to provide more detail about the decrease and increase in costs associated with the RIF. The Company replied to Data Request 262 (Confidential Exhibit Staff/305) that the savings to Oregon customers should be $0.264 million annually. Staff is taking Avista's assurances that the savings are included in this case as true although the Company has been unable to demonstrate that the savings were actually there by showing a reduction in ongoing expenses. In Avista/100, Morris/7-8, the Company shows a graph that depicts "…non-fuel Operations and Maintenance and Administration and General Expenses are growing at a faster pace than sales".

The piece that is the most worrying is the increase in costs of $0.550 million due to the severance pay-out, which was not removed from this rate case as a one-time occurrence. Staff can find no evidence that Avista has removed it. Generally, with a cost of this type of action, a utility company will submit an application for a deferral when the program begins and then at a later time after the program ends will amortize the deferral. Because Avista did not inform Oregon Staff of the RIF and did not ask for a deferral, Staff believes it was considered as just another cost and collected on an on-going basis from customers. Staff plans to review UG 246 and UG 284 to see if an adjustment should have been made. If Staff determines that the Company has kept the $0.550 million in rates and over-collected the amount, Staff will initiate talks with the Company to find a solution. The Company should have made an adjustment to remove this one-time cost from expenses.

Q. Does Avista believe that it has removed this cost?

A. Apparently, yes. In the Company's response to Staff Data Request 262, on page two, Avista states "Severance payments are not included in rates in

Oregon as per the Settlement Stipulation, UG-246, Order No. 14-026 on page 5". When Staff reviewed Order No. 14-026 it was discovered that the Order is only a single page and therefore cannot have a page 5. Staff then examined the main order in Docket UG-246 which is Order No. 14-017. This Order contains the Stipulation. The Order and the Stipulation were thoroughly examined by two different Staff and no reference to removing severance payments was found. Staff can only conclude that the Company is mistaken.

Q. Has Staff removed this cost?

A. Yes. Staff has made an adjustment to lower expenses by $0.550 million to remove the one-time cost from expenses.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Judy A. Johnson	
EMPLOYER:	Public Utility Commission of Oregon	
TITLE:	Senior Economist Energy Rates, Finance and Audit Division	
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301	
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington	
	BA in Accounting from Eastern Washington University Cheney, Washington	
EXPERIENCE:	3/95-Present	I have been employed by the Oregon Public Utility Commission since March of 1995. My current position is as a Senior Economist in Energy, Rates, Finance, and Audit.
	6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UG 288
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/19/2015
CASE NO.:	UG 288	WITNESS:	Karen K. Schuh
REQUESTER:	PUC Staff - Johnson	RESPONDER:	Larry La Bolle
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff-264	TELEPHONE:	(509) 495-4710
		EMAIL:	larry.labolle@avistacorp.com

REQUEST:

Please provide, in as much detail as possible, the following detail about the CSS:

a. How did the actual cost of CSS compare to what was budgeted?
b. If there were any cost over-runs, please fully explain them.
c. Please provide support for the amount of CSS in Oregon.
d. The amount and date that CSS went into plant-in-service.

RESPONSE:

The Company's legacy Customer Information and Work and Asset Management System, which was in service for twenty years, was replaced in a multi-year effo1t named "Project Compass." The legacy applications replaced included the Company's Customer Service System, Work Management System, and the Electric and Gas Meter Application. The primary replacement systems are Oracle's Customer Care & Billing application and International Business Machine's ("IBM") Maximo work and asset management application. A p01tion of the Maximo system was enabled in the fall of 2013, and the full System was placed in service in February 2015.

a. The initial implementation budget for Project Compass was developed in 2012, based on the system requirements inf01mation developed as part of the initial project plan. The basis for the initial budget of approximately $79 million was described in a project report filed in support of testimony describing Project Compass, which was part of the Company's 2013 general rate case in Oregon. In particular, that testimony highlighted the nature of large enterprise-wide software projects like Compass, and the preliminary nature of the estimates. In June of 2014, Avista revised the initial budget to approximately $98 million, and prepared a report describing the project factors that were resulting in greater workload, development and testing time, and cost. That repo1t, which was filed in supp01t of the Company's 2014 general rate case in Oregon, also described some of the mitigation measures implemented by the Compass project team to manage changes in the workload and time requirements. The report is provided here as Staff_DR_264 Attachment A. A final revision to the budget for Project Compass (approximately $106 million) was made in November 2014, and the new systems were placed into service on February 2, 2015. The final implementation cost was approximately $106 million.
b. While the Company expected that the final cost for Project Compass would very likely be greater than the initial budget developed in 2012, Avista does not consider it reasonable to characterizing this difference as a "cost overrun." Rather, the amount spent by the Company to implement the new systems represents the true installation cost. As explained

in part a, above, accurately predicting the final implementation cost was not possible at the time the initial budget was developed. The report, provided as Staff_DR_264 Attachment A, describes the major activities that required more time and money to complete than was initially estimated.

c. Avista's customer information and asset management system is a company-wide platform that supports and enables the provision of service to customers receiving electric or natural gas service in any of Avista's service territories. Therefore, this asset is treated as a common asset in terms of both service and jurisdiction, and the net plant balance is allocated to Avista's services and jurisdictions based upon Avista's established allocation methodology. The most current common service and jurisdiction allocation factor for Oregon is 8.702%, which is the allocation factor included in this case for Project Compass net plant. Please see Avista's responses to DRs Staff_DR_ 128 through Staff_DR_l34, which include information regarding Avista's established allocation methodology.

d. The table below details the transfers to plant-in-service associated with Project Compass. During 2013 and 2014, portions of the overall project that were in service prior to the whole-system go-live were transferred to plant-in-service. The whole-system Go-Live occurred on February 2, 2015 and the associated capital expense was placed in service in February 2015. Ce1iain trailing capital expenditures were transferred to plant-in-service in the months following February 2015. These trailing expenditures are associated with the activities of Post-Go Live Support and Project Stabilization, where are elements of the capital project.

Period	Transferred to Service (in thousands of $)
2013	10,390
2014	262
January 2015	
February 2015	85,988
March 2015	3,486
April 2015	2,167
May 2015	2,206
June 2015	2,872
July 2015	108

CASE: UG 288
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Confidential Exhibits in Support
Of Opening Testimony

October 16, 2015

STAFF EXHIBIT 303

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

CASE: UG 288
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

October 16, 2015

In addition, the Commission has made it clear that the company bears the burden of demonstrating prudence.[89]

Q. Why is Staff contesting the prudence of Avista's additional capital costs for Project Compass?

A. Avista's explanation, contained in the testimony and exhibits of Mr. Kensok, does not tell the whole story behind the reasons for Project Compass' cost overrun and implementation delay. The Company's responses to Staff s discovery requests[90] reveal that the primary contributor to the added capital costs was the performance of Project Compass' System Integrator (SI)[91] for the Oracle Customer Care & Billing (CC&B) solution: EP2M/Five Point/Ernst & Young.[92]

Staff s recommendation to disallow Avista's capital costs relating to the extended timeline are based on the following issues, which I discuss below: 1) the failure on the part of Avista to recognize, evaluate, identify, document and mitigate the possible risks to Project Compass resulting from the apparent conflict of interest arising from five Point's acquisition of EP2M less than six months after award of a contract; 2) Avista's failure to cure contractual breaches on the part of the SI early

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[89] Ibid., p. 13 ("As with all issues, the company bears the burden to prove initiation, construction and continuation of the project was prudent"); *see Petition of Puget Sound Power & Light Co. for an Order Regarding the Accounting Treatment of Residential Exchange Benefits,* Docket No. UE-920433, Eleventh Supplemental Order (Sept 21, 1993), p. 19 ("Puget must make an affirmative showing of the reasonableness and prudence of the expenses under review . . . even in the absence of a challenge by another party").

[90] Avista's responses to Staff Data Request Nos. 140, 141, 152, 153 and 154. See Gomez, Exh. Nos. _(DCG-l5C), (DCG-16C), (DCG-l6C), (DCG-J 8C), and (DCG-19).

[91] The Company also uses the term "Solution Integrator," which is synonymous in meaning to "System Integrator."

[92] Staff's reference here to multiple companies is the result of two separate mergers and acquisitions of Avista's SI during the tenure of this project. EP2M was acquired by Five Point in January of 2013, and Ernst and Young acquired Five Point on June 1, 2014.

enough in the project, which could have avoided the need for an extension of the project's timeline and added cost; and 3) the Company's lack of documentation of the prudence of its decision, above other alternatives, to enter into an Extension Agreement with Ernst & Young (EY) for the added resources needed to complete Project Compass.[93]

Q. What was the function of the CC&B System Integrator for Project Compass?

A. The CC&B SI for Project Compass is tasked with aligning the product standard configuration components of Oracle's off-the-shelf CC&B software to meet key business goals, minimizing the need for product extensions and, to the greatest extent possible, modifying Avista's business processes to align with best practices inherent in the product workflow. Additionally, the SI actively supports cooperation with the other concurrent system projects like Maximo Asset Management.[94]

Q. Please explain the conflict of interest that arose when Five Point acquired EP2M.

A. Prior to its acquisition of EP2M, Five Point was operating in the capacity of an agent of Avista in the procurement of SI services for Project Compass.[95] In its confidential

[93] Gomez, Exh. No._ (DCG-16C), Avista's supplemental response to Staff Data Request No. 141, Attachment A, Project Change Request (PCR) FP 23N -Revised and Extended EY SI Services and Project Change Request (PCR) FP 24N - Extension, completion, and true up of EY resources - all signatures.

[94] Gomez, Exh. No. __ (DCG-15C), Avista's confidential response to Staff Data Request No. 140, Attachment A, EP2M 04 -EP2M Avista Project SOW 7.9.2012, Page 15, Section 4.1 Project Objective.

[95] Gomez, Exh. No. __ (DCG-31C), UE-140188, Kensok, Exh. No. JMK-2, Attachment 10, "Project Compass Guidebook" dated January 27, 2012, shows Five Point personnel (Greg Galluzzi and Gary Weseloh) actively involved in contract negotiations and development of statements of work with SI vendors including EP2M which received the contract award.

response to Staff Data Request No. 140, the Company acknowledges it knew of the merger and acquisition at the time it occurred, which was in January 2013. Avista then states that "the interests of its customers were insulated from any potential conflict of interest by the rigorous and objective processes it established for developing vendor proposals, evaluating and scoring proposals, making final vendor selections, and in negotiating the final contracts, purchase agreements, and purchase prices."[96] Avista's assertion that its procurement process was not compromised and did not impact project results is an after-the-fact statement that cannot be confirmed.

Q. Why is the integrity of the procurement process so important in the selection of an SI for Project Compass?

A. The integrity of the procurement process is an important consideration in the vendor performance risk assumed by the Company for this project. This is especially the case given that Avista's award to EP2M resulted in a Firm Fixed Price Contract for deliverables contained in the SI's Statement of Work (SOW).[97] The nature of such contracts places the primary cost risk onto the seller, in this case EP2M. Therefore, the bid of an offeror (here EP2M) has to be responsive to the requirements contained in the scope of work only and not affected by other influences. Otherwise, an unacceptable level of performance risk is introduced that the awarded amount is below the offeror's costs and the project under-resourced.[98]

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[96] Gomez, Exh. No.__(DCG-l5C), Avista's confidential response to Staff Data Request No. 140.
[97] Ibid., Attachment A, 01 - EP2M Deal Sheet 6.29.2012 and 04 – EP2M Avista Project SOW 7.9.2012.
[98] Ibid., Attachment B, provides monthly Project status reports, prepared for the Executive Steering Committee for the calendar year 2014. On the very first monthly report of the year (page 5 of 2664), project management

Q. Do you believe that the conflict of interest that arose after EP2M's acquisition by Five Point resulted in an awarded amount that was below cost and in a project that was under resourced?

A. Staff cannot say with certainty that the SI bid was affected in any way by Five Point's acquisition of EP2M or that Five Point's decision to buy EP2M was somehow motivated by the prospect of an awarded contract by Avista. Staff only need point to Five Point's integral and active involvement in Project Compass' SI procurement contained in Mr. Kensok's Exhibit No. JMK-2 in UE-140188 and Five Point's subsequent performance problems commencing early in the project as a successor to EP2M as evidence of questions that should have been asked of Five Point by Avista's project management and Executive Steering Committee. Avista has not provided documentation that such questions were addressed.

Q. You point to Avista's failures to cure contractual breaches as another reason to disallow the costs of the extended timeline for Project Compass. Please explain.

A. In Avista's confidential response to Staff Data Request No. 152,[99] it provides a lengthy explanation regarding its "due diligence in evaluating the consequences of a decision to enforce contract provisions against Five Point," which contradicts its earlier narrative in Mr. Kensok's testimony and exhibit regarding the circumstances surrounding the project's extended timeline and added costs being the result of

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reports as an issue that "Five Point bas been challenged with resources to deliver integration and configuration code to meet Project deliverable dates."

[99] Gomez, Exh.No. (DCG-17C).

greater than anticipated complexity. In its response to Staff Data Request No. 152, the Company refers Staff to the reports it provided in its Attachments B and C to Staff's Data Request No. 140 as evidence that it prudently evaluated its options, including termination of the contract, to address the SI's non-performance in delivering usable code for System Integration Testing, a critical path item for the project. Staff s review of these reports located no evidence of such discussions or analysis. Nor does Staff find evidence that such options were explored or discussed in the materials presented to the Board in May/June 2014 to extend the project timeline and add another $20.0 million to the project's budget.[100]

Q. Why does Staff believe that an early and aggressive response by Avista to the SI's contractual breach might have led to different results for Project Compass?

Avista's contract with the SI was performance based. This means that the Company structured its payments with EP2M/Five Point on the successful completion of SOW deliverable milestones based on mutually agreed upon acceptance criteria. The contract's payment structure also included "holdback" amounts for deliverables. The holdback amounts would be payable upon successful delivery of the completed solution by the SI. Based on Avista's response to Staff Data Request No. 152, Staff concludes that the Company continued to make payments to a vendor that was clearly not performing. As a result, the Company lost any leverage to compel the SI to cure its breach, particularly the further along the project moved toward its Go-

[100] A copy of the presentation made to the Company's Finance Committee of its Board of Directors, supporting

the revision of the Go Live date and implementation budget, were provided by Avista in response to Staff Data Request No. 153, Confidential Attachment A. See Gomez, Exh. No. __ (DCG-18C).

CASE: UG 288
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 305

Confidential Exhibits in Support
Of Opening Testimony

October 16, 2015

STAFF EXHIBIT 305

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

CASE: UG 288
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Depreciation

Opening Testimony

October 16, 2015

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

A. My name is Ming Peng. I am employed by the Public Utility Commission of Oregon (OPUC) as a Utility and Energy Analyst 3 in the Energy Rates, Finance and Audit Division. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. I reviewed the depreciation expense and depreciation reserve portions of Avista Corporation's (AVA or Company) revenue requirement rate case filing as documented by witness Smith in Avista/500-502 and witness Schuh in Avista/600.

Q. What exhibits do you include as part of your testimony?

A. I have prepared the following exhibits:

Exhibit Staff/401, Witness Qualification Statement, consisting of three pages, and Exhibit Staff/402, AVA Data Response No. 152, consisting of two pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. Analysis of Capital Recovery Parameters

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> *As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.*[1]

Q. Where can the current authorized depreciation rates be found for AVA?

A. The current authorized depreciation rates for the Company can be found in Commission Order 13-168 (Docket UM 1626).

Q. How did you analyze the depreciation expense, and what information did you review for the Company's rate case filing?

A. To check if the depreciation calculation is properly conducted by using the authorized depreciation parameters in Commission Order 13-168, I performed the following analytical review procedures:

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1 NARUC "Public Utility Depreciation Practices," p 318.

1. I sent one set of data requests (DR 152) to AVA on May 29, 2015. I asked the company to provide the following information:

the calculation in Excel format with the cell reference links and formulae for exhibits AVISTA/502, Smith, and for AVISTA/600, Schuh. The data set could include, but not limited to, the following:

1) CAP SUMMARY- OR - 12.31.15 EOP (w 2016 AMA Growth) – linked
2) EOP and Full Year Depreciation Adjustments – linked
3) Filed - 2015 OR Gas Rev Req Model
4) Transportation Depreciation Study Support
5) UM 1626 Settled Exhibit 102 Attachment A-linked

2. I verified the calculations from AVA's data responses to DR 152, including:

(1) checked the reference links, formulae, and calculations from the data response.

(2) reviewed how the Company derived the "weighted average depreciation rate" by using the rates in Order 13-168.

(3) verified how Company forecasted 2015 and 2016 depreciation expenses

(4) reviewed how the Company's adjustments to depreciation expense were calculated

Q. Did you make any adjustments and, if so, for what reasons?

A. Yes. In the current general rate case (UG 288) filing, I discovered that certain depreciation rates had not been correctly updated by the Company. AVA should use depreciation parameters and rates from Order 13-168. To comply with the Commission Order's authorized depreciation rates for the Company, I propose the following adjustments and corrections:

1. Depreciation & Amortization expenses be reduced by $281,000 from

$3,183,000 to $2,902,000; and

2. Accumulated Depreciation & Amortization be reduced by $173,000 from $8,322,000 to $8,149,000.

The table below shows the comparison of the "aggregated" depreciation rates that derived by using AVA filed and OPUC authorized depreciation rates. The depreciation expense and accumulated depreciation adjustments are based on the calculations by using Oregon PUC authorized depreciation rates.

UG 288 - AVA	**OPUC Authorized**	**AVA Filed**	**Difference**
Description	Aggregated	Aggregated	Authorized
	Depreciation Rate	Depreciation Rate	Less Filed
Gas Underground Storage	1.88%	1.59%	0.29%
Distribution			
Direct	2.05%	2.52%	-0.47%
Allocate All Jurisdictions	2.05%	2.52%	-0.47%
Allocate Northern Jurisdictions	2.05%	2.52%	-0.47%
Subtotal			
General Plant	7.00%	3.62%	3.38%
Transport.	8.06%	8.92%	-0.86%
Compass-Hardware	6.66%	23.70%	-17.04%
Hardware	20.00%	23.70%	-3.70%

Q. Please describe your activities with regard to reviewing the Company's filing.

A. In order to get a better collective understanding of AVA's depreciation adjustment, I conducted two phone conferences with AVA's Data Responder David Machado. As I understand it, Mr. Machado works with the Company's witness Karen Schuh. The conference calls concerned my proposed depreciation adjustments.

Q. Please describe data responses to Staff's DR 152 provided by AVA.

A. AVA's data response (Exhibit Staff/402) to DR 152 was on time, relevant and complete. The Company provided five files relating to DR-152 A.B.C.D.E in excel format. Further, in its response, AVA stated as follows:

> *Subsequent to the filing of the general rate case, it was discovered that certain forecast depreciation rates had not been correctly updated.*
>
> *These depreciation rates have been appropriately updated in the files submitted in response to this data request, and the "CAP SUMMARY-OR – 12.31.15 EOP (w 2016 AMA Growth) – linked" file (Staff_DR_152 Attachment A to this response) reflects these updated depreciation rates. The calculation of forecast depreciation expense and the forecast accumulated depreciation (depreciation reserve) are included.*

In its data response (DR) No. 152, AVA updated its depreciation calculation and forecasting by using the depreciation rates authorized by the Commission.

ISSUE 2, Depreciation Effect on Revenue Requirement

Q. Describe the depreciation effect on the revenue requirement of a utility.

A. In the traditional rate base rate-of-return environment, customer rates and utility costs are components of a utility's revenue requirement. NARUC in its "Public Utility Depreciation Practices", "Depreciation Expense and Its Effect on the Utility's Financial Performance – Revenue Requirement" states:

> *Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.*

Q. Please identify Oregon's relevant statute regarding utility depreciation rates.

A. It is ORS 757.140, which states in relevant part:

> *(1) Every public utility shall carry a proper and adequate depreciation account. The Public Utility Commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such*

rates of depreciation from time to time as the commission may find to be necessary.

Q. How are depreciation rates used in determining the utility's revenue requirement?

A. In a general rate case filing, the depreciation expense is calculated by using the Commission's authorized depreciation rates (in this case, those set forth in Order 13-168), and in traditional FERC classification of generation, transmission, distribution and general plant assets.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

C.R.R.A. Certified Rate of Return Analyst
Society of Utility and Regulatory Financial Analysts

Depreciation studies - the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

EXPERIENCE: 1/11/1999-Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 16 years since January 1999. My roles include: Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst. I have testified in various formal state hearings. I have performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

<u>Principal Analyst & Case Manager, Settlement leader/negotiator for Depreciation:</u>
For the depreciation rate determination (fixed cost allocation) in revenue requirement, I have served as a principal analyst and case manager for the determination of Energy Property Depreciation Rates (ORS 757.140) for last eight years.
In this position, I investigate, analyze and calculate the Cost and Impact on Customer Rates for Coal-plant "Shutdowns", Hydro-plant Shutdowns, "Old Plant Retirement" and "New Plant Investment".

The New Plant Depreciation Rates determinations listed for the following Cases:

UM 1679 and UE 294

1. PGE Port Westward 2, Gas Plant
2. Tucannon River Wind Farm,
3. Carty, Gas plant,

The Power Plant Shutdown Removal & Depreciation Cost for the following:

1. PGE closes Boardman Coal plant (UM 1679 & UE 215) ,
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246)
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 - Recovery of investment in Klamath River dams in OPUC UE 219.

I calculate and determine the depreciation rates including the analyses on all energy assets under the FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants; the energy source I have worked on including "Steam Production Plant", "Hydraulic Production Plant", "Other Production Plant" including "Natural Gas", "Wind", and "Solar" Plants.

I conduct case investigation and energy asset analysis, make rate adjustments, lead settlement negotiation, and prepare and present testimony on behalf of Commission staff related to each of the six energy companies: (1) PacifiCorp, (2) Portland General Electric, (3) Northwest Natural Gas, (4) Idaho Power, (5) Avista Corp, and (6) Cascade Gas under the commission's regulatory jurisdiction.

I also perform an analysis of "Rate Impact Calculation of Oregon Clean Energy Capital Investment, Comparative Advantage of Oregon Clean Energy – Dollar Impact in rates".

Lead Analyst and Case Manager on Financial Dockets:

Prior to my present position, I was a lead analyst and case manager for nine years. My responsibilities in that position included: financial risk analysis on the application of Derivative Instruments filed by utilities while they conduct Financial Hedging and Capital Raising Activities.

I passed the test and become a "Certified Rate of Return Analyst". I was involved with more than 60 PUC UF financial dockets before the Commission for PacifiCorp, Portland General

Electric, Northwest Natural Gas, Idaho Power, Avista Corp, and Cascade Gas, and water companies.

Public Utility & Policy Analyst:

Energy Merger & Acquisition: I have testified in formal state hearings involving Energy Merger & Acquisition, I conducted Acquisition Premiums & Credit Risk Analysis and testified for the Merger case of “PacifiCorp vs. MidAmerican Energy Company” (a subsidiary of Berkshire Hathaway Energy) in UM 1209. My reviews for Energy Merger & Acquisition have also included “PacifiCorp vs. Scottish Power”, “PGE vs. Enron".

I testified in UP-158, PGE Fuel Price Forecasting and Property Sales; I reviewed Electricity Load Forecasting, Weather Normalization for energy companies in IRP and rate case filing; I conducted the Statistical Sampling Design and Procedure Design, and testified on Revenue Issues (UM 1288), Analysis for General Rate Case components, and other regulated utility issues.

My work functions have also included Integrated Resource Planning (IRP) filing review for PacifiCorp, PGE and Northwest Natural Gas Companies. I conducted Energy Utility Auditing for cost of capital component on all energy companies and operational audit on Idaho Power Company.

I have conducted Interest Rate and late payment charge Survey and Analysis for state of Oregon (UM 779), conducted Market Competition and Economic Policy Survey Analysis and Report in Oregon Telecommunications Industry (HB 2577) and the report has been published on OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators

I was also selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. I taught various subjects on Incentive Regulation, comparing the Rate and Economic Impacts of “Cost-Of-Service” regulation in US and “Price-Cap” regulation in Europe, Cost of Capital, Energy Demand and Price Forecasting Models, Least Cost Planning, and policy issues affecting Utility Rates.

CASE: UG 288
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	06/01/2015
CASE NO.:	UG 288	WITNESS:	Karen Schuh
REQUESTER:	PUC Staff - Peng	RESPONDER:	David Machado
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 152	TELEPHONE:	(509) 495-4554
		EMAIL:	david.machado@avistacorp.com

REQUEST:

152. Please provide the calculation in Excel format with the cell reference links and formulae for exhibits AVISTA/502, Smith, and for AVISTA/600, Schuh. The data set could include, but not limited to, the following:

1) CAP SUMMARY- OR - 12.31.15 EOP (w 2016 AMA Growth) – linked
2) EOP and Full Year Depreciation Adjustments – linked
3) Filed - 2015 OR Gas Rev Req Model
4) Transportation Depreciation Study Support
5) UM 1626 Settled Exhibit 102 Attachment A-linked

152.1 Please provide the cell reference links and formulae, in Excel format, between the "book rate" Avista used in this filing and the "depreciation rates" the Commission approved in Order 13-168. For the rates Avista used that are not in the Order, such as Intangible Assets, please explain how these rates are determined.

152.2 Please provide the calculation of <u>forecasted</u> depreciation expense and reserve for each year 2015 and 2016 with the cell reference links and formulae.

152.3 Please add cell reference links and formulae on Total Adjustments to Depreciation & Amortization (+3,183) and Accumulated Depreciation & Amortization (-8,322) in "Avista/501, Smith/1 of 11."

RESPONSE:

152. Items 1, 2, 4, and 5 listed above are included as Staff_DR_152 Attachments A, B, D, and E, respectively. Item 3 listed above, "Filed – 2015 OR Gas Rev Req Model," was previously provided with our original filing in this general rate case – we have included this file again, in response to this data request, as Staff_DR_152 Attachment C.

152.1. The cell reference links and formulae, in Excel format, requested in the request are included in the files entitled "EOP and Full Year Depreciation Adjustments – linked" and "UM 1626 Settled Exhibit 102 Attachment A-linked," which we have included as attachments Staff_DR_152 – Attachment B and Staff_DR_152 – Attachment D in our response to DR 152.

For depreciation rates that were not included in Order 13-168, Docket UM-1626, the depreciation rates used in the current filing are equal to the depreciation rates identified in the depreciation study from which the rates included in the aforementioned Order 13-168 were sourced. For depreciation rates associated with new fixed asset accounts that were not present as of the most recent depreciation study, the depreciation rates used in the current filing represent the effective depreciation rate in the base year (average-of-monthly-averages for the twelve months ended December 31, 2014).

Subsequent to the filing of the general rate case, it was discovered that certain forecast depreciation rates had not been correctly updated. These depreciation rates have been appropriately updated in the files submitted in response to this data request, and the "CAP SUMMARY-OR – 12.31.15 EOP (w 2016 AMA Growth) – linked" file (Staff_DR_152 Attachment A to this response) reflects these updated depreciation rates. Following the aforementioned updates, the updated balances for Total Adjustments to Depreciation & Amortization and Accumulated Depreciation & Amortization are $2,900 and ($8,147), respectively. The impact to revenue requirement is a decrease of $277,000.

152.2. The calculation of forecast depreciation expense and the forecast accumulated depreciation (depreciation reserve) are included within the file entitled "CAP SUMMARY – OR – 12.31.15 EOP (w 2016 AMA Growth) – linked," which is included as attachment Staff_DR_152 – Attachment A in our response to this data request.

152.3. The cell references and formulae for the Total Adjustments to Depreciation & Amortization (+3,183) and Accumulated Depreciation & Amortization (-8,322) in "Avista/501, Smith/1 of 11 have previously been included within the originally filed native format Excel file entitled "*Filed – 2015 OR Gas Rev Req Model*."

For further clarification, within this native format workpaper, the $3,183 Total Adjustment to Depreciation & Amortization is the sum of cells AT59, AT93, AT143, AT148, and AT160 on the tab entitled "Exh 502-ADJ Detail Input." Likewise, the ($8,322) Total Adjustment to Accumulated Depreciation & Amortization is equal to cell AT244 on the "Exh 502-ADJ Detail Input" tab.

Each of the aforementioned cells (AT59, AT93, AT143, AT148, AT160, and AT244) reflect the cross-sum of all adjustments. However, adjustments to depreciation & amortization expense and accumulated depreciation & amortization only occurred within adjustments 2.05, 2.06, and 2.07, which are included in columns Y, Z, and AA in the "Exh 502-ADJ Detail Input" tab. The adjustment balances included in these three adjustments come from the respective adjustments calculated and included within the "CAP SUMMARY-OR – 12.31.15 EOP (w 2016 AMA Growth)" file, which was included in Ms. Schuh's native format workpapers.

CASE: UG 288
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

D&O Insurance, Various A&G

Opening Testimony

October 16, 2015

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

A. My name is Linnea Wittekind. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to recommend two adjustments[1]:

1. Directors & Officers (D&O) Insurance $[redacted]
2. Various A&G $30,323

Q. Did you prepare an exhibit for this docket?

A. Yes. I in addition to my witness qualification statement, I prepared four exhibits they are as follows:

1. Exhibit Staff/502, consisting of 2 pages – Staff Calculations
2. Exhibit Staff/503, consisting of 1 page – Data Response No. 229
3. Exhibit Staff/504 consisting of 2 pages – An excerpt from OPUC Order No. 09-020
4. Exhibit Staff/505 consisting of 2 pages – An excerpt from OPUC Order No. 09-020

Q. How is your testimony organized?

A. My testimony is organized as follows:

[1] See Exhibit Staff/502 pages 1 & 2 for staff's calculation of the adjustments.

Q. How many data requests did you review as part of your analysis of D&O Insurance and Various A&G issues?

A. I reviewed 18 multi-part standard data requests and four follow up data requests.

ISSUE 1, D&O INSURANCE

Q. Briefly describe your analysis related to D&O Insurance.

A. Avista included in its filed case $[redacted] in total company D&O Insurance expense, which is $[redacted] on an Oregon-allocated basis. This amount represents the first layer (premium layer) as well as first, second, third, fourth, fifth excess layers in addition to an A-side layer of D&O Insurance[2]. My analysis is that 50 percent of the total cost of all layers of D&O Insurance should be removed from A&G, which is consistent with Commission past practice. Based on my analysis, removing 50 percent of D&O Insurance would result in an Oregon-allocated adjustment of $[redacted].

Q. What is your reason for removing 50 percent of D&O Insurance?

A. In Docket UE 197, Staff proposed that customers and ratepayers share the cost of excess layers of D&O liability insurance. The Commission agreed the cost of D&O liability insurance should be split between ratepayers and shareholders. In fact, the Commission ordered that the Company absorb a greater amount of the cost of D&O insurance than proposed by Staff:

> We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost.[3]

Consistent with this ruling, Staff proposed an adjustment in Docket UE 283 removing 50 percent of the entire cost of D&O Insurance. Staff/500,

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[2] *See* Avista's confidential response to Staff Data Request No. 229 included as Exhibit Staff/503.
[3] OPUC Order No. 09-020 at 19-20. An excerpt of the relevant rulings from that Order is included in Exhibit Staff/504.

Wittekind/3 Docket UE 283). Staff's adjustment was settled in the second partial stipulation in that docket, which was adopted by the Commission in Order No. 14-422.

ISSUE 2, VARIOUS A&G

Q. Briefly describe your analysis of Various A&G.

A. Avista included in its UG 288 filing $60,645 in expense for meals, entertainment and employee recognition identified in FERC Accounts 500 – 935. My analysis of these accounts leads me to recommend removal of 50 percent of the meals, entertainment and employee recognition expenses as consistent with Commission past practice.

Q. What is your reason for removing 50 percent of these items from Various A&G?

A. Because the costs for meals, entertainment and employee recognition are discretionary and not required to provide safe and adequate service to customers, Staff's practice is to recommend a 50 / 50 sharing of expenses between customers and shareholders.

In Commission Order No. 09–020 (UE 197), the Commission adopted Staff's recommendation concerning meals and entertainment expenses and ordered the 50 percent sharing between customers and shareholders. The Commission stated on page 21:[4]

> We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders.

Q. Does this conclude your testimony?

A. Yes.

---

[4] Docket No. UE 197, OPUC Order No. 09-020 at 21. An excerpt of the relevant rulings from that Order is included in Exhibit Staff/505.

CASE: UG 288
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Linnea Wittekind
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance & Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	B.S. WESTERN OREGON UNIVERSITY MAJOR: BUSINESS WITH FOCUS IN ACCOUNTING MINOR: ENTREPRENEURSHIP

EXPERIENCE:

Since November 2009, I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric and natural gas utilities. I have provided testimony in UE 215, UE 233, UG 221, UG 284, UE 246, UE 294 and UM 1741 and have filed comments in LC 50 as well as various UP and UI dockets. I have also reviewed and analyzed a number of energy efficiency tariff filings. I've written several public meeting memos summarizing my analysis of the energy efficiency tariff filings. I have performed operational audits of NW Natural, Cascade Natural Gas, and Portland General Electric as well as assisted in an operational audit PacifiCorp. Recently I've completed an audit regarding gas accounting best practices and labor benchmarking.

Through the Public Utility Commission of Oregon, I am a member of the NARUC Staff Subcommittee on Accounting & Finance.

I've attended a number of trainings which include, The Basics through the Center for Public Utilities, New Mexico State University, Best Practices in an Era of Renewables and Reduced Emissions through EUCI as well as Benchmarking the Performance of Electric and Gas Distribution Utilities also through EUCI. I've also attended the Advanced Regulatory Studies Program through the Institute of Public Utilities at Michigan State University.

From July 2005 to November 2009, I worked as a Tax Auditor for the Oregon Department of Revenue. In enforcement of tax laws, rules and regulations, I performed income tax audits of individual tax payers and small businesses. Additionally I prepared cost analysis of tax credits and measures. I also represented the department before the Oregon Tax Court for tax deficiency appeals.

CASE: UG 288
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Confidential Exhibits in Support Of Opening Testimony

October 16, 2015

STAFF EXHIBIT 502

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

THE EXHIBIT IS AN EXCEL FILE
AND IS INCLUDED ON THE
CONFIDENTIAL CD FILED WITH
THE FILING CENTER
AND
IS AVAILABLE ON HUDDLE
TO PARTIES WITH HUDDLE CONFIDENTIAL ACCESS

CASE: UG 288
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Confidential Exhibits in Support
Of Opening Testimony

October 16, 2015

STAFF EXHIBIT 503

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

CASE: UG 288
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 504

Exhibits in Support
Of Opening Testimony

October 16, 2015

Staff supports Occupational Health Benefits, but disagrees with PGE's proposed increase in funding for the program. Although participation has increased 46 percent between 2006 and 2008, Staff notes that actual program costs have only increased about 1.7 percent. Staff proposes to allow $224,434 in funding for Occupational Health Benefits for 2009, which is an increase of approximately 19 percent over two years.[67] With respect to the IAM program, designed to reduce employee absences, Staff asserts that PGE has failed to link the program to cost reductions benefitting customers, and therefore costs associated with the program should be disallowed.[68] Staff supports Occupational Fitness, but believes that PGE's requested level of funding is unsupported by the record, which shows a recent decrease in costs.[69] Staff also proposes to remove the Recreation Program from the revenue requirement, as these activities are discretionary, take place outside the workplace, and are not required to provide safe and adequate service to customers.[70] Staff supports the Health Club Partial Reimbursement program, but questions whether increasing classes and activities will almost double program costs as indicated by PGE. Instead, Staff supports allowing a 20 percent increase resulting from increased participation for the test year.[71] Staff proposes to adjust the proposed expense for Service Awards in a manner similar to the adjustment for merit-based bonuses—50 percent to customers and 50 percent to shareholders. Finally, Staff recommends disallowance of expenses for Retiree Association and Retiree Luncheon because they are not required to provide safe and adequate service to customers, and to disallow all other unidentified, and therefore unjustified, expenses.[72]

In response, PGE claims that these benefits represent a comparatively small amount of overall benefits yet are a critical part of an overall package designed to attract and retain qualified employees.

Resolution

We concur with Staff's analysis and adopt the calculations contained in Staff/900, Ball/10, to adjust PGE's 2009 revenue requirement through the disallowance of $319,000.

g. Insurance

Staff proposes several adjustments to PGE's requested test-period, insurance-related expense. First, Staff cites falling premiums in the current soft market and recommends no escalation for property and liability premiums.[73] Second, Staff proposes to eliminate 50 percent of the excess Directors' and Officers' (D&O) insurance

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[67] Staff/900, Ball/5-6.
[68] *Id. at* 6-7.
[69] *Id.* at 7.
[70] *Id.* at 8.
[71] *Id.*
[72] *Id.* at 9.
[73] Staff/300, Ball-Dougherty/9; Staff/901, Ball/3.

as a shareholder cost. D&O insurance protects PGE senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. According to Staff, "[c]ustomers, who have no say in electing or appointing PGE's Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits."[74] Third, Staff proposes to apply a utility allocation percentage to the overall insurance premiums to allocate the cost between the utility and non-utility aspects of PGE's operations.[75] Finally, Staff proposes a $1.75 million adjustment to PGE's Uninsured Losses based on escalating the five-year historical average by inflation.[76]

PGE contends that D&O liability insurance is a normal cost of doing business, and the entire cost should be included in its revenue requirement. PGE also includes updates to its policies in rebuttal testimony and claims Staff did not properly consider certain policies. PGE further noted that flat insurance rates can still result in increased premiums when property values increase. The Company proposed that the utility allocation factor adjustment should be applied only to a limited number of specific categories.[77]

Resolution

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost. We also adopt Staff's proposal to hold premiums steady for 2009 property and liability insurance and apply the utility allocation percentage to overall policy premiums. In addition, we adopt Staff's adjustment to Uninsured Losses. PGE's 2009 revenue requirement is therefore reduced by $3.717 million.

h. Miscellaneous Expenses

These expenses consist primarily of costs for catering, gifts, promotional items, and civic activities, including lunch meetings and gifts to employees for overtime work or as retirement gifts, sympathy gifts to employees' families, holiday activities and "team-building days for employees."

Staff proposes that 50 percent of the meal and entertainment expenses, office refreshments and catering, gifts of flowers, and awards be disallowed. In Staff's view, these expenses should be shared equally between ratepayers and shareholders. This approach somewhat mirrors the policy associated with bonuses and the handling of meal and entertainment expenses for income tax purposes.[78]

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[74] *See* Staff/900, Ball/11.
[75] *Id.* at 15.
[76] Staff/300, Ball-Dougherty/11; Staff/900, Ball/14; Staff/901, Ball/4.
[77] PGE Opening Brief at 33-36 and testimony cited therein.
[78] Staff Opening Brief, citing Staff/300, Ball-Dougherty/13-15.

CASE: UG 288
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 505

Exhibits in Support
Of Opening Testimony

October 16, 2015

as a shareholder cost. D&O insurance protects PGE senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. According to Staff, "[c]ustomers, who have no say in electing or appointing PGE's Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits."[74] Third, Staff proposes to apply a utility allocation percentage to the overall insurance premiums to allocate the cost between the utility and non-utility aspects of PGE's operations.[75] Finally, Staff proposes a $1.75 million adjustment to PGE's Uninsured Losses based on escalating the five-year historical average by inflation.[76]

PGE contends that D&O liability insurance is a normal cost of doing business, and the entire cost should be included in its revenue requirement. PGE also includes updates to its policies in rebuttal testimony and claims Staff did not properly consider certain policies. PGE further noted that flat insurance rates can still result in increased premiums when property values increase. The Company proposed that the utility allocation factor adjustment should be applied only to a limited number of specific categories.[77]

Resolution

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost. We also adopt Staff's proposal to hold premiums steady for 2009 property and liability insurance and apply the utility allocation percentage to overall policy premiums. In addition, we adopt Staff's adjustment to Uninsured Losses. PGE's 2009 revenue requirement is therefore reduced by $3.717 million.

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[74] *See* Staff/900, Ball/11.
[75] *Id.* at 15.
[76] Staff/300, Ball-Dougherty/11; Staff/900, Ball/14; Staff/901, Ball/4.
[77] PGE Opening Brief at 33-36 and testimony cited therein.
[78] Staff Opening Brief, citing Staff/300, Ball-Dougherty/13-15.

Staff also proposes removing 100 percent of civic activities recorded in Administrative & General (A&G) accounts, noting "the Commission has not previously allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. . . . In addition, Commission policy does not require customers to support causes in which they do not believe."[79]

PGE asserts that these discretionary costs are appropriately included in rates, because these miscellaneous expenses create a business culture that allows the utility to attract and retain qualified workers.[80]

Resolution

We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. We also adopt Staff's recommendation with respect to contributions to charities, community affairs, and economic development organizations. PGE provides no rationale to change our existing policies, and we conclude that all contributions to charities, community affairs, and economic development organizations should be disallowed. PGE's 2009 revenue requirement is reduced by $710,000 to reflect the disallowance of these expenses.

We also acknowledge PGE's removal of Directors' Compensation and Officer Vehicles from the proposed 2009 test-year budget. The total revenue-requirement reduction for miscellaneous expenses is $1.18 million.

i. Senate Bill 408 Ratio Adjustment

Senate Bill 408 (SB 408) requires the Commission to establish certain ratios in general ratemaking proceedings, which will be used to determine the amounts of "taxes collected" from customers for the purpose of the SB 408 true-up of "taxes paid" to "taxes collected." PGE believes that, in setting the tax rate and margin ratios here for SB 408 purposes, the Commission should consider the impact of costs that have been disallowed. PGE explains that, "[t]o do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible."[81]

Staff opposes PGE's proposal as an attempt to insulate its shareholders from sharing the tax benefit of disallowed expenses with ratepayers when truing up the amount of taxes collected. Staff believes PGE's request is inconsistent with the terms of SB 408, as well as Commission rules implementing the bill.[82] According to Staff, the Commission indirectly addressed this issue when it declined PGE's request for a deferral

[79] *Id.*, citing Staff/300, Ball-Dougherty/15.
[80] PGE Opening Brief at 37, citing PGE/2700, Piro-Tooman/12.
[81] PGE/2300, Tooman-Tinker/24.
[82] *See* ORS 757.268 and OAR 860-022-0041.

CASE: UG 288
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 600

Plant Capital Additions

Opening Testimony

October 16, 2015

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

A. My name is Mitchell Moore. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. What recommendations, if any, do you propose in your testimony?

A. I am responsible for reviewing the capital additions that Avista Corporation (Avista or Company) proposes in its filing. For reasons I will explain, I recommend a reduction of approximately $30 million from the Company's capital forecast. I will show that Avista's request in this proceeding is extraordinary and far exceeds its historical rate base growth rate. Avista's level of capital additions is not supported by the Company's relatively flat growth in terms of number of customers, as well as an overall decline in gas sales. In addition, absent compelling evidence showing a need for such extraordinary growth, the Company should increase its rate base at a measured rate to meet service and safety requirements while maintaining cost control.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/602	Responses to DR #'s 188-189
Exhibit Staff/603	Response to DR #190 – HVAC upgrade
Exhibit Staff/604	Avista investor update; 2014 Integrated Resource Plan (IRP) material.
Confidential Staff/605	Avista pipeline capacity presentation

Exhibit Staff/606 *Excel* file, Moore workpapers

Q. Please summarize Avista's filing regarding capital additions.

A. Avista proposes to increase its net rate base in Oregon 20.3 percent by adding approximately $45.6 million to its Oregon plant base in 2015, and an additional $2 million for customer hookups for the first quarter of 2016.[1] Of that amount, $16 million is proposed for general plant projects, which include items and activities such as technology upgrades, website redevelopment, transportation and tool replacements, as well as the continuation of the Company's long-term campus restructuring.

The largest project in the General Plant additions is the implementation of Project Compass, the Company's new Customer Information and Asset system. However, I do not address Project Compass in my testimony, and it is not part of my adjustment recommendations, except to the extent that the amount recommended to be allowed for total capital additions in this proceeding would include Project Compass. In other words, the Company's increasing its rate base at a measured level would include the expenditures associated with Project Compass. This project is addressed in Ms. Judy Johnson's testimony in Staff/300.

For Oregon gas distribution projects, Avista proposes adding $30.2 million in capital additions.[2] These projects include various programmatic (ongoing) growth-related work, infrastructure updating, Aldyl-A Pipe replacement, street and highway replacements, as well as some large discrete projects.

[1] See Avista/600, Schuh/9-10
[2] Ibid, p.10

Q. How did Staff perform its analysis and arrive at its recommended adjustments?

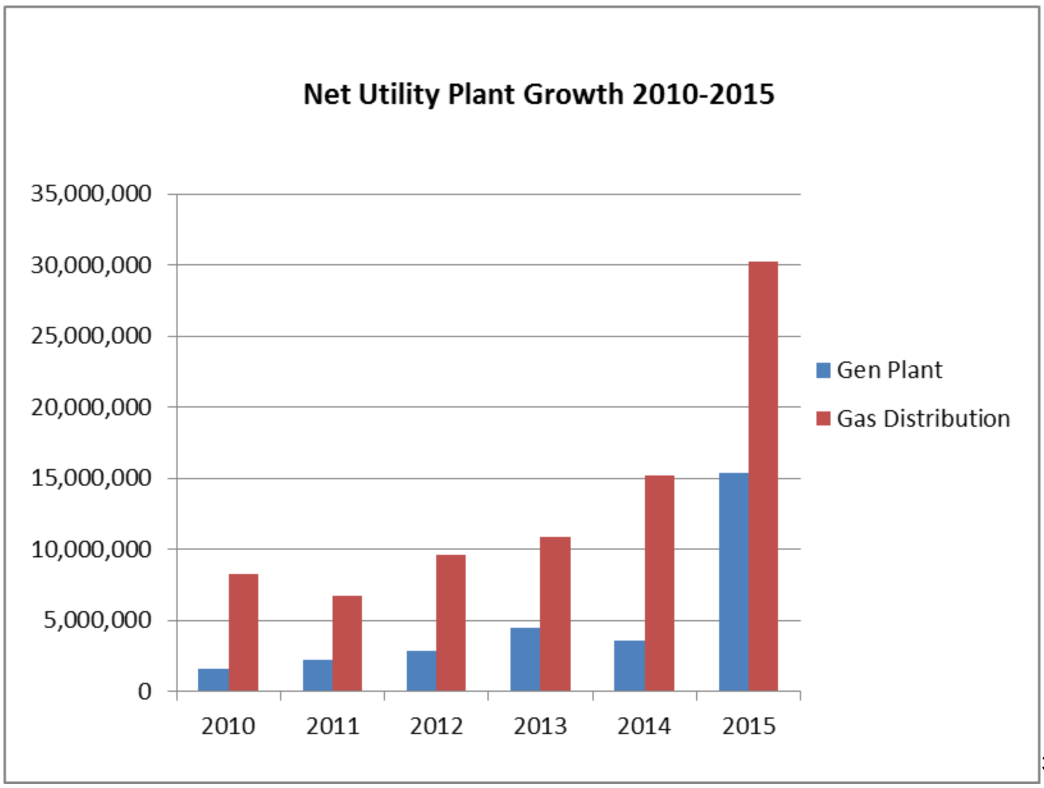
A. Staff began with the principle that the Company should make sufficient capital investment to allow it to provide safe and adequate service while being mindful of controlling costs. This principle conflicts with a goal of accelerating rate base growth with the objective of increasing earnings given weak customer growth and reduced demand.

Under normal operating conditions (e.g. absent a natural disaster or other *force majure*), growth in rate base should happen at a measured pace so that rate-payers are not burdened with sharp rate increases that far outpace the rate of inflation in order to reward its shareholders. It is up to the Company to identify and prioritize appropriate rate base additions to maintain a healthy plant in order to provide safe, reliable service to its customers at just and reasonable rates. Stated differently, it is the Company’s prerogative as to how it chooses to manage its investments to both control costs, provide safe and adequate service, and attract capital.

Q. Please explain how the capital additions proposed in this proceeding compare with Avista’s plant growth in prior years.

A. The capital additions in this filing represent a dramatic increase over the additions made relative to the historical average in the years from 2002-2013. The Company is proposing to grow its net plant base by a significantly higher percentage than the historical average. For example, Avista’s current filing represents a 22.6 percent increase over last year's net plant base, and in 2014 the Company added 11 percent to its plant base. The historical average of net plant growth from 2002 through 2013 is 7.75%. In this filing, the Company proposes a three-fold increase of its net plant base over the 7.75% historical average. Figure 1 below illustrates the relative increase in the current and prior year:

Figure 1



[3]

Q. What does Staff consider a reasonable rate of growth in rate base?

A. For the purposes of this filing, Staff considered two things: a) the Company's historical growth rate from 2002-2013; and b) Avista shareholder presentations

[3] Exhibit Staff/602, Moore/1-2; Data obtained from Company DR responses 188 Attachment C and 189 Attachment C

that highlight a 5-6 percent annual growth in rate base as an attractive investment proposition.[4]

From 2002-2013 the average growth in net plant base was 7.75 percent. The growth over that time period ranged from a high of about 18.9 percent in 2008 to a low of 1.8 percent in 2004.[5] The historical average of 7.75 percent is high compared to the 5-6 percent system-wide annual growth rate that the Company asserts in its presentations represents an attractive investment. If 2014 is added to that average, it rises to 8 percent. This suggests that historically Oregon rate payers have, on average, borne a higher share of rate base growth than customers in other jurisdictions. This higher growth rate may be reasonable if there has been more customer growth in Oregon, or other unique circumstances in Oregon that require more capital investment than in other states. For the purposes of this proceeding, it is entirely possible that Oregon's average net rate base growth rate of 7.75 percent is justifiable, even though it is higher than the Company's system-wide average growth rate. However, the growth in net plant base of 22.6 percent represented by this filing is extraordinary, and is not justified by the evidence presented in this case.

Q. What does Staff recommend for a growth rate in this case?

A. For the purposes of this proceeding, Staff recommends 7.75 percent rate base addition for 2015. The Company's Project Compass, which came online in February of this year, represents an atypically large and discrete investment of

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[4] Exhibit Staff/604, Moore/1-4: Avista Corporation Investor Update, June 2015
[5] Exhibit Staff/606, Excel tab: "ROO 2001-2014": data from Avista's annual Results of Operations Report 2002-2013.

$106 million ($8.3 million Oregon allocation). The implementation of this one-time project may justify a growth in rate base for this year that, even though consistent with Oregon's historical average, is higher than the standard 5 to 6 percent system-wide growth rate.

Q. Please discuss the proposed capital additions relative to the Company's growth in Oregon.

A. The Company's capital additions in recent years, and particularly that proposed in this year's filing, is growing dramatically while customer demand is relatively flat, and total gas sales have declined. As a consequence, Avista's customer rates are approximately 37% higher than are Cascade Natural Gas's rates, which is a similarly-situated Oregon gas utility.[6] Between 2007 and 2014, Avista's net plant base has doubled from $106 million to $211 million.[7] In contrast, year-end residential customers over that same period have only increased three percent, commercial customers have increased 2.5 percent, and industrial customers have increased 11 percent.[8] Moreover, total therms sold to all classes of customers has decreased 7.7 percent from 2007-2014.[9] Figures 2 and 3 on the following page illustrate the relationship between Avista's capital plant additions and its customer and sales growth:

[6] Exhibit Staff/606, Moore/workpapers; tab "Average Bill"; calculation derived from average December sales to residential and commercial customers.
[7] Exhibit Staff/606, Moore/workpapers; tab Avista Results of Operations, 2007 and 2014.
[8] Exhibit Staff/606, Moore/workpapers; tab Staff DR# 193 Att A, SAS forecast data; calculation derived from customer count for month of December each year.
[9] Ibid. calculation derived from therms sold in December each year.

Figure 2

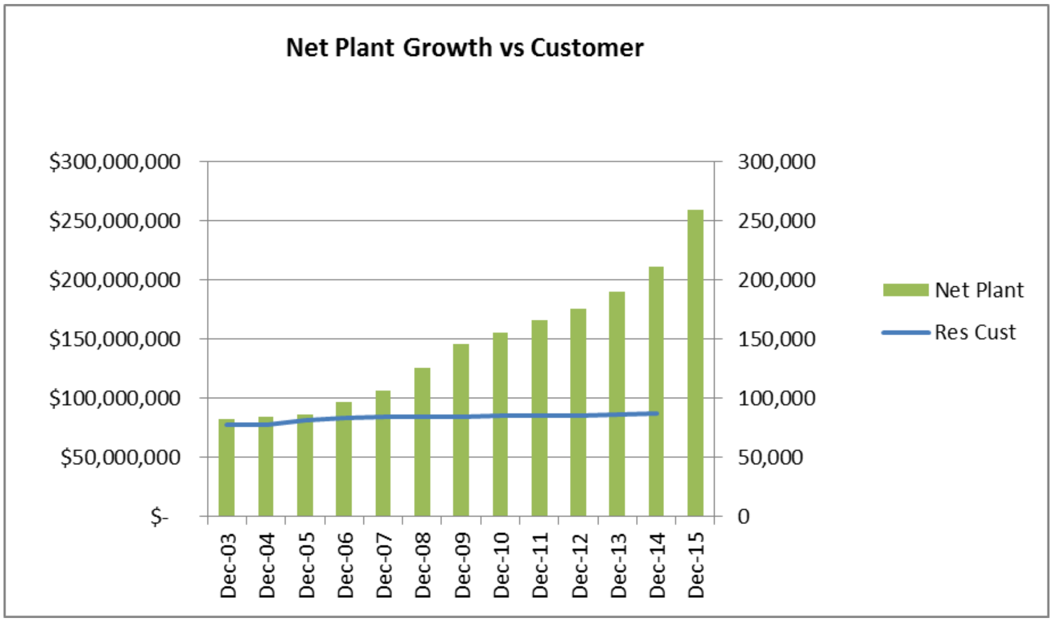
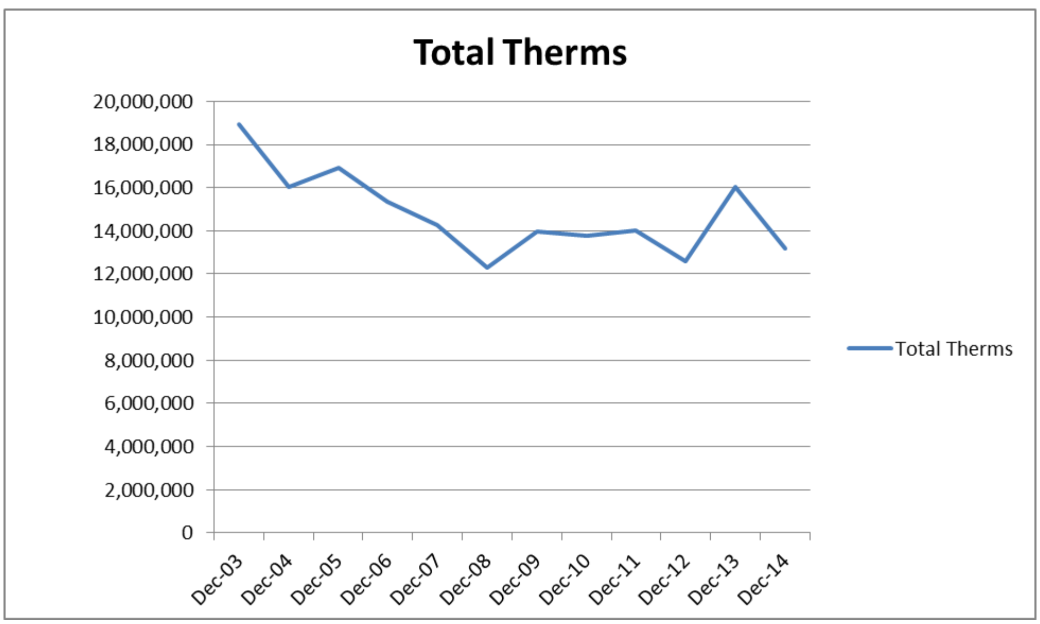


Figure 3



Q. Does the Company have a financial incentive to increase its rate base?

A. It certainly appears so. In reports to investors, the Company highlights its utility infrastructure investment and increasing rate base as a positive aspect of the Company's overall financial condition driving earnings and dividend growth.[10] In its Direct Testimony, the Company states that it expects future revenue growth to be "relatively flat" as result of "weak customer growth and flat use-per-customer."[11] Therefore, one clear and remaining avenue to achieve earnings and dividend growth would be increasing rate base.

Q. Is Avista's investment in Oregon growing faster than the Company's system-wide growth?

A. Yes. In its most recent update to investors in June 2015, the Company presents a five to six percent rate base growth through utility capital investments. The Company's highlighting a five to six percent rate base growth in its presentations to investors implies that this level of growth is sufficient to attract investors. However, as noted above, the growth in net plant in Oregon from 2002-2013 has been nearly 7.75 percent. In this context, the 20.2 percent net rate base growth in this filing and the 2014 net increase of 11.2 percent is truly extraordinary. In addition, it suggests that Oregon rate payers are being asked to shoulder an outsized share of the Company's system-wide rate-base growth.

Q. How did the Company develop its projection of rate base in this proceeding?

[10] Exhibit Staff/604, Moore/1-4: Avista Corporation Investor Update, June 2015
[11] Avista/100, Morris/7

A. The Company developed its projection of rate base in this proceeding based on an end-of-period December 31, 2014 calculation.[12] The rate base amount was forecasted based on actual plant in service on December 31, 2014, adjusted for capital additions forecast over calendar year 2015. The Company then adds forecast adjusted monthly average costs for new customer hookups through 2016.

Q. Please describe the 2015 capital additions proposed by the Company.

A. The Company provided a list of 40 capital projects that it has forecast to be placed in service in calendar year 2015.[13] The list consists of both discrete capital projects, as well as blanket capital projects. Blanket capital projects are non-discrete, or routine, capital expenditures, such as technology and communications upgrades, replacement of aging infrastructure, vehicle and tool maintenance. Collectively these capital additions amount to $45.6 million on an Oregon-allocated basis. ($8.3 million of this amount is attributable to Project Compass, as discussed above.) System-wide, the capital additions total $245.3 million.

Q. What documentation does the Company provide surrounding these capital projects?

A. For most projects the Company included with its direct testimony a "Capital Program Business Case" form containing a high-level description, as well as approved budget amounts for the project.[14] Attached as Exhibit Staff/605,

[12] Avista/600, Schuh/3-4
[13] Avista/600, Schuh/9-10
[14] Schuh Workpapers ET-1, pgs 1-73

Moore/9 is a sample of Capital Program Business Case forms for the projects Staff has reviewed in this proceeding. As can be noted, most of the forms contain little detail surrounding the specific project activities to be undertaken. Other than high-level statements that the project will be beneficial, the Company's forms do not contain project timelines or a calculation of expected customer benefit. The Company provided additional information for projects. above $500,000, in response to follow-up to Staff Data Request Nos. 190-192 and 231-238.

Q. In Staff's view, are capital program business case forms adequate documentation for inclusion of the underlying associated investment in the Company's revenue requirement?

A. Generally, no. The Capital Program Business Case forms do not contain adequate information to determine whether a particular project is prudent and beneficial to rate-payers. The forms contain no calculations that would demonstrate that the projects will result in concrete economic benefits to ratepayers. This lack of detail indicates that the Company may not be performing a sufficient evaluation of these factors when budgeting new capital projects. In addition, the budget amounts approved in the Capital Program Business Case forms are often significantly lower than the capital amounts proposed in the Company's filing.

Q. Please provide examples of what you found to be an insufficient form.

A. A prime example is the form for project #5005 Technology Refresh to Sustain Business Process. The capital cost associated with this project in 2015 is estimated at $13.9 million in the business case form; the approved amount, which presumably tacks on O&M and other costs, is $16.1 million. [15] But in the Company's filing, approximately $21.4 million system-wide ($1.9 million Oregon-allocated) is included for the project. [16]

Another example is the COF HVAC Improvement project #7101. The total project request for this multi-year project is for $39.8 million. The budget timeline in the form spreads this total across 2012-2014. But then an additional $5.7 million is approved for 2015 with no explanation. And yet in the filing, the Company doubles this amount and includes nearly $11 million ($955,000 Oregon-allocated).[17] I discuss this project further below.

Q. Was the additional supporting information supplied in response to Staff data requests sufficient to justify the capital expenditures?

A. Generally, no. In some cases the information supplied might make the case for a reduced capital budget. An example is project #7101, the COF HVAC Improvement discussed above. Avista wants to add $11 million system-wide ($955,000 Oregon allocated) in 2015 for this multi-year HVAC system replacement project that appears to have begun in 1998. The plan was originally developed at an estimated cost of $7.5 million. Attached is Exhibit Staff/603, Moore/1-11, which contains part of the Company's response to DR #190, in which Staff requested all project justification materials to demonstrate why the project is necessary for Oregon operations at this time. The response

[15] Exhibit Staff/604, Moore/9: Project Capital Program Business Case for ER#5005, Technology Refresh
[16] Avista/600, Schuh/9
[17] Ibid.

included an executive update given in 2008, which shows the project costs increased from an initial $7.5 million in 1998 to an updated estimate of $12.2M in 2008. The scope of the project then increased to include additional HVAC systems, and other various upgrades at a projected cost of $5.7 million, which put the projected cost at $17.4 million. Between the years 2010-2014 alone, the Company had spent a total of $25.5 million.[18] It is unknown what Avista spent on this project prior to that. For 2015, an additional $11 million ($0.96M Oregon allocated) in capital addition is projected, but there is no information that demonstrates what the additional amount is for and why it would be considered beneficial to rate payers. In fact the dramatic expansion of the program over the years to include multiple upgrades and “green additives” may indicate that the Company is simply seeking capital addition opportunities for increasing its rate base that are not necessary and related to providing service to customers. The information supplied by the Company in support of this HVAC project is vague, high-level, outdated, and not nearly sufficient to justify this level of capital spending.

Q. Are there other projects for which the Company supplied additional information that Staff nevertheless is recommending disallowing for cost recovery in rates?

A. Yes, this is the case for most projects in the filing. A different kind of example is the East Medford Reinforcement project #3203, for which the Company seeks $5 million. The project is a 3.2-mile pipe installation to complete a 12” high-

[18] Exhibit Staff/602, Moore/1: Response to Staff DR #188

pressure loop across the east side of Medford, Oregon. The completion of the pipeline loop would increase capacity in the area. In the Company's response to DR 233, in confidential attachment B, the Company provides a slide presentation that gives an overview of capacity projects, in which the East Medford Reinforcement project is discussed. The presentation is about designing the gas distribution system to have the capacity to meet demand on "design day" temperature days, where extreme cold weather places higher-than-normal load on the system. Certain areas of the system have capacity deficiencies to meet demand at design day temperatures. East Medford is one of those areas.

However, the presentation also discusses how the Company has historically addressed these deficiencies by producing a "Cold Weather Action Plan" – or CWAP- in which personnel are deployed to manually bypass [regulator] stations and inject CNG into the system to keep the pressures up. The presentation notes that Avista has "not had to activate the CWAP in the last several years due to a combination of milder temperatures and a stronger system…" Nevertheless, the Company's "goal is to not have any cold weather action plans, but to have a system that is strong enough to support our design day loads, without manual intervention."[19]

Q. What is Staff's reasoning for recommending a disallowance on this particular project?

[19] CONFIDENTIAL Exhibit STAFF/605, Moore/3

A. Staff does not dispute that the East Medford pipeline project is necessary, but the Company has not presented compelling evidence to show that the project is so urgent that it must be completed this year. It does not appear nearly urgent enough in the context of a rate base increase of this magnitude. The Company's 2014 Integrated Resource Plan (IRP) identifies the East Medford reinforcement as one of its upcoming distribution projects scheduled for 2018. The IRP states: "Previous IRP and distribution planning analysis identified a near-term resource deficiency driven by forecasted local growth. Increased natural gas deliveries from the TransCanada Pipeline….will remedy this deficiency….This has been a multi-phase project spanning several years. As forecasted, needs have changed over time, and with no immediate resource need, completing the final phase of the project has been delayed."[20]

Staff supports the completion of this project, but the Company has not provided a compelling reason that it must be completed this year.

Regarding Avista's justification of capital distribution projects generally, it is not only in this filing where the Company's evidence is insufficient. Staff's comments to the 2014 IRP state: "…Staff finds it is missing a clear presentation of how Avista decides which distribution system projects to include in the IRP, and a clear description of the included projects, along with a justification for recommending or proceeding with the projects."[21]

[20] Exhibit STAFF/604, Moore/5-7: *"Avista Utilities 2014 Natural Gas IRP" p. 129*
[21] Exhibit STAFF/604, Moore/8: *OPUC ORDER NO.15-063, Appendix A, p. 10*

Q. What is Staff's adjustment and how did you arrive at it?

A. Staff recommends removing approximately $30 million from the Company's capital additions. This adjustment is in addition to the specific adjustment for Project Compass recommended by Ms. Johnson, who recommends a $1.3 million reduction.

Staff arrives at this adjustment of $30 million by setting a target for growth of net utility plant of 7.75 percent, which equates to a rate base addition of approximately $16.4 million. This results in a $31.3 million overall reduction in capital projects. From this amount, I subtract the $1.3 million adjustment to Project Compass made by Ms. Johnson in Staff/300. This leaves a $30 million adjustment to the overall capital budget.

Capital addition adjustment	
7.75%	Historical RB growth
$210,751,974	2014 Net Utility Plant
$47,658,000	UG 288 Avista Capital forecast
($16,333,278)	2014 net plant * 7.75%
($31,324,722)	Total Staff Adjustment
($1,300,000)	Project Compass Adjustment - J. Johnson
($30,024,722)	Net Staff Adjustment - M. Moore

Please refer to Exhibit Staff/606 Excel workpapers for the details of my recommended adjustment.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints. Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UG 288
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

October 16, 2015

Avista Corp
Actual Transfers to Plant: 2010-2014 (General Plant Capital Projects)
Staff DR 188 Attachment C

System Balances

Sum of Current Activity Cost SUM			Year						OR	OR Allocated Balance				
Erval	Jurisdiction	Asset Service	2010	2011	2012	2013	2014	Grand Total	Allocation %	2010	2011	2012	2013	2014
2277	AA	CD			1,067,211	12	485,690	1,552,913	8.702%	-	-	92,869	1	42,265
		GD					189,753	189,753	30.918%	-	-	-	-	58,668
5005	AA	CD	6,245,256	8,906,528	7,252,015	10,829,014	12,157,847	45,390,661	8.702%	543,462	775,046	631,070	942,341	1,057,976
		GD					36,441	36,441	30.918%	-	-	-	-	11,267
5006	AA	CD	2,263,886	5,567,590	5,878,977	5,473,024	4,459,561	23,643,038	8.702%	197,003	484,492	511,589	476,263	388,071
		GD			336,971			336,971	30.918%	-	-	104,185	-	-
5010	AA	CD	39,891	153,347	539,440	259,795	266,087	1,258,559	8.702%	3,471	13,344	46,942	22,607	23,155
		GD					10,478	10,478	30.918%	-	-	-	-	3,240
5014	AA	CD				2,002,533	869,234	2,871,767	8.702%	-	-	-	174,260	75,641
	OR	GD			32,487	25,496		57,983	100.000%	-	-	32,487	25,496	-
5106	AA	CD	108,225	62	7,465,012	3,344,494	11,483,620	22,401,412	8.702%	9,418	5	649,605	291,038	999,305
5138	AA	CD				10,390,158	138,886	10,529,044	8.702%	-	-	-	904,152	12,086
		GD					123,107	123,107	30.918%	-	-	-	-	38,062
5143	AA	CD				48,281	301,867	350,148	8.702%	-	-	-	4,201	26,268
5144	AA	CD					319,525	319,525	8.702%	-	-	-	-	27,805
		GD					262,027	262,027	30.918%	-	-	-	-	81,014
7000	AA	CD	15,093	33,690			37,057	85,840	8.702%	1,313	2,932	-	-	3,225
	OR	GD	176,304	480,871	109,246	530,175	0	1,296,596	100.000%	176,304	480,871	109,246	530,175	0
7001	AA	CD	2,183,983	2,876,313	3,017,087	659,195	2,238,406	10,974,984	8.702%	190,050	250,297	262,547	57,363	194,786
	OR	CD					(483,555)	(483,555)	100.000%	-	-	-	-	(483,555)
		GD	154,132		94,354	139,763	172,288	560,536	100.000%	154,132	-	94,354	139,763	172,288
7003	AA	CD	434,858	488,437	549,006	788,838	92,159	2,353,298	8.702%	37,841	42,504	47,775	68,645	8,020
7006	AA	CD	1,524,316	1,165,627	1,722,726	329,327	524,187	5,266,183	8.702%	132,646	101,433	149,912	28,658	45,615
		GD	100,778	25,733	212,034	49,758	898,575	1,286,879	30.918%	31,159	7,956	65,557	15,384	277,821
	OR	GD			34,048			34,048	100.000%	-	-	34,048	-	-
7101	AA	CD	5,080,239	5,169,309	3,861,466	6,411,556	4,947,204	25,469,774	8.702%	442,082	449,833	336,025	557,934	430,506
7126	AA	CD			54,062	10,111,250	982,481	11,147,792	8.702%	-	-	4,704	879,881	85,495
7200	AA	CD		105,165	12,664		36,949	154,778	8.702%	-	9,151	1,102	-	3,215
Grand Total			18,326,961	24,972,673	32,238,806	51,392,669	40,549,874	167,480,983		1,918,883	2,617,865	3,174,015	5,118,162	3,582,237

Avista Corp
Budgeted Transfers to Plant: 2010-2014 (Gas Distribution Capital Projects)
Staff DR 189 Attachment C

Sum of Current Activity Cost SUI			Year						OR Allocation % [C]					OR Allocated Balance					
Erval	Asset Serv	Jurisdictio	2010	2011	2012	2013	2014	Grand Total	**2010**	**2011**	**2012**	**2013**	**2014**	**2010**	**2011**	**2012**	**2013**	**2014**	**Total**
1001	GD	AA	15,000,001	12,053,001	12,863,814	9,672,698	10,601,277	60,190,791	30.118%	29.425%	28.669%	32.935%	31.268%	4,517,700	3,546,596	3,687,927	3,185,703	3,314,807	18,252,733
1050	GD	AA	1,500,000	1,525,000	1,826,903	1,709,468	1,768,579	8,329,950	30.118%	29.425%	28.669%	32.935%	31.268%	451,770	448,731	523,755	563,013	552,999	2,540,269
1051	GD	AA	650,000	160,000	242,102	296,322	305,825	1,654,249	30.118%	29.425%	28.669%	32.935%	31.268%	195,767	47,080	69,408	97,594	95,625	505,474
1053	GD	AA	500,000	500,000	500,812	605,863	627,280	2,733,955	30.118%	29.425%	28.669%	32.935%	31.268%	150,590	147,125	143,578	199,541	196,138	836,972
3000	GD	AA	472,501	470,000	799,999	350,000	1,000,000	3,092,500	30.118%	29.425%	28.669%	32.935%	31.268%	142,308	138,298	229,352	115,273	312,680	937,910
3001	GD	AA	1,049,999	1,052,002	800,001	600,002	800,001	4,302,005	30.118%	29.425%	28.669%	32.935%	31.268%	316,239	309,552	229,352	197,611	250,144	1,302,898
3002	GD	AA	420,001	500,001	399,999	400,000	600,000	2,320,001	30.118%	29.425%	28.669%	32.935%	31.268%	126,496	147,125	114,676	131,740	187,608	707,645
3003	GD	AA	1,260,003	1,850,001	2,199,999	2,000,000	4,500,000	11,810,003	30.118%	29.425%	28.669%	32.935%	31.268%	379,488	544,363	630,718	658,700	1,407,060	3,620,328
3004	GD	AA	472,500	500,000	500,001	500,001	800,000	2,772,502	30.118%	29.425%	28.669%	32.935%	31.268%	142,308	147,125	143,345	164,675	250,144	847,597
3005	GD	AA	3,360,002	2,900,002	3,822,998	3,949,690	5,600,000	19,632,692	30.118%	29.425%	28.669%	32.935%	31.268%	1,011,965	853,326	1,096,015	1,300,830	1,751,008	6,013,145
3006	GD	AA	440,000	440,000	499,999	900,000	900,000	3,179,999	30.118%	29.425%	28.669%	32.935%	31.268%	132,519	129,470	143,345	296,415	281,412	983,161
3007	GD	AA			1,095,000	2,348,333	2,598,333	6,041,666	30.118%	29.425%	28.669%	32.935%	31.268%	-	-	313,926	773,423	812,447	1,899,796
3008	GD	AA			5,000,000	8,250,000	16,452,196	29,702,196	30.118%	29.425%	28.669%	32.935%	31.268%	-	-	1,433,450	2,717,138	5,144,273	9,294,860
3055	GD	AA					1,000,000	1,000,000	30.118%	29.425%	28.669%	32.935%	31.268%	-	-	-	-	312,680	312,680
3117	GD	AN	217,860	360,000	370,800	511,010	400,000	1,859,670	30.118%	29.425%	28.669%	32.935%	31.268%	65,615	105,930	106,305	168,301	125,072	571,223
3203	GD	OR	597,355		550,056	-		1,147,411	100%	100%	100%	100%	100%	597,355	-	550,056	-	-	1,147,411
7201	GD	AA		580,666	630,000	1,000,000	500,000	2,710,666	30.118%	29.425%	28.669%	32.935%	31.268%	-	170,861	180,615	329,350	156,340	837,166
		AN	429,000					429,000	0.000%	0.000%	0.000%	0.000%	0.000%	-	-	-	-	-	-
Grand Total			26,369,222	22,890,673	32,102,483	33,093,387	48,453,491	162,909,256						8,230,120	6,735,581	9,595,821	10,899,307	15,150,438	50,611,266

CASE: UG 288
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Exhibits in Support
Of Opening Testimony

October 16, 2015

Executive Update

April 23, 2008 **DRAFT 4/18/08 Noon**

HVAC history and project costs

Early 1990s: critical equipment failure in central plant

1994 – 1997: Spent $1.6M

1998: Multi-year project plan developed with cost estimate of $7.5M

1999: Complete $300K work

1999 – 2000: Tom Matthews' growth strategy focuses on subsidiaries

2001 – 2005: Financial on Fundamentals to rebuild the Utility, credit rating

2006: Spent $130K on designing HVAC for G&P shop

- Updated cost estimate **$12.2M from MW Engineering** (excl. tax, escalation, architect)

2007: $1M for HVAC upgrades completed

- G&P, electric, gas meter shops.
- Request GMAX price for Design & Build from **McKinstry**

2008: $5M approved for service building, cafeteria/auditorium, window wall

AVISTA

Changes in scope

1.	Additional HVAC Systems added due to age	$ .822M
2.	Lighting and Electrical System Upgrades	$1.371M
3.	Window Interior Shading System	$ .529M
4.	Additional Glazing of Buildings	$ .219M
5.	Fire Sprinkler Systems	$ .517M
6.	General Construction (Ceilings/Fireproofing)	$2.242M
	TOTAL	**$5.70M**

HVAC current budget outlook

	2008	2009	2010	2011	2012	Subtotal	2013	2014	Total
Budget * in $Millions	$4,990	$4,159	$3,327	$2,733	$3,000	$18,209			
McKinstry GMAX	$4,936	$1,713	$3,600	$3,541	$3,667	$17,457	$3,943	$4,286	$25,686

* Budget represents Long Range Plan Placeholder Amount

AVISTA

LEED strategy for Existing Building

- HVAC renovation & remodeling positions Avista for LEED Existing Building certification at completion
- Lighting & ceiling costs could be reduced
  - re-use existing systems
- Discuss future floor plan design
  - day lighting and views
- Implementing new floor plan design requires purchasing interior wall system and some furniture
- Fireproofing and fire sprinkler systems are life safety improvements – not LEED related

AVISTA

Possible scenarios

Scenario 1: Reduce scope of work

• Lighting and Electrical System Upgrades	$1.371M
• Window Interior Shading System	$ .529M
• Additional Glazing of Buildings	$ .219M
• Fire Sprinkler Systems	$ .517M
• General Construction (Ceilings/Fireproofing)	$2.242M
TOTAL	**$5.70M**

Scenario 2: Compress work schedule to reduce escalation costs

- Savings TBD. Need to explore options with McKinstry

Scenario 3:

Questions?

Page 10

CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER.

LEED estimates and green additives

	Code Bldg.	Certified	Silver	Gold	Platinum
Best Estim.	$10.6M	$11M	$11.9M	$13.5M	$16.7M
LEED Pts.	0–26	26 – 32	33 – 38	39 – 51	52 – 69
Green Additives	Design/Build contractor No additives Boiler/Chiller 208 swales	Traditional HVAC Recycling program White roof Reduce water 20% Storm wtr. qual. ctrl. Reduce energy 14% Basic lighting sys.	HVAC heat pump Advcd. Mech. Sys. Adv. stormwater ctrl. Reduce water 30% Reduce irrigat. 50% Reduce energy 42%	All of Silver PLUS 35kW solar panels Rain garden Green roof canopy Shade trees/parking Reduce energy 42%	Green tech. demo. proj. 30% onsite generation Onsite waste treatment Gray water recycling Reduce energy 42%
Future Expenses	Avg energy bills Avg O&M Costs Avg Carbon Print	Avg energy bills Avg O&M Costs Avg Carbon Print	Low energy bills Low O&M Costs Low Carbon Print	Low energy Bills Lower O&M Costs Lower Carbon Print	Lowest energy bills Lowest O&M Costs Zero Carbon Print

AVISTA

Ross Court reductions

Land transfer fee removed (Utility Accounting)		**$600K**
Green additives removed		**$433,200**
Green roof (entry canopy only)	$12K	
35kW PV Array	$350K	
Rain gardens	$27K	
Parking lot trees	$11K	
Subtotal Alternatives	**$400K**	
Sales Tax	$33,200	
Total Alternatives	**$433,200**	
Well estimate removed		**$100K**
Reduce estimating contingency		**5%**
Reduce general contractor markup (improved market conditions)		**2%**

AVISTA

Investing in:
our facilities, our environment and our business

Replace current HVAC system
- 50 years old
- Outdated
- Inefficient

New HVAC system
- Energy efficient
- Other energy renovations to building

New Building
- 38,000 sq. ft. facility
- Relocate employees during renovation
- Accommodate future growth
- LEED certified building
- Legacy of Environmental Stewardship

CASE: UG 288
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA®

Positioned for performance: An overview of Q1 2015 and beyond

June 2015

NYSE: AVA

www.avistacorp.com

Steadily building long-term value

Projecting earnings and dividend growth of 4% to 5%

Avista Utilities

- 5% to 6% rate base growth through utility capital investments
  - Upgrading infrastructure
  - Grid modernization
- Customer and load growth (~1%)

AEL&P

- Strong near-term rate base growth through investment in generation
- Customer and load growth (~1%)
- Evaluating LNG/LDC* opportunities

Strategic Investments

- Developing platforms for future growth
  - Targeting expanded natural gas services via LNG
  - Exploring data science and advanced analytics

Reliably building value for our customers, investors, communities and employees

*LNG: Liquefied natural gas
LDC: Local distribution company

AVISTA

Avista Utilities

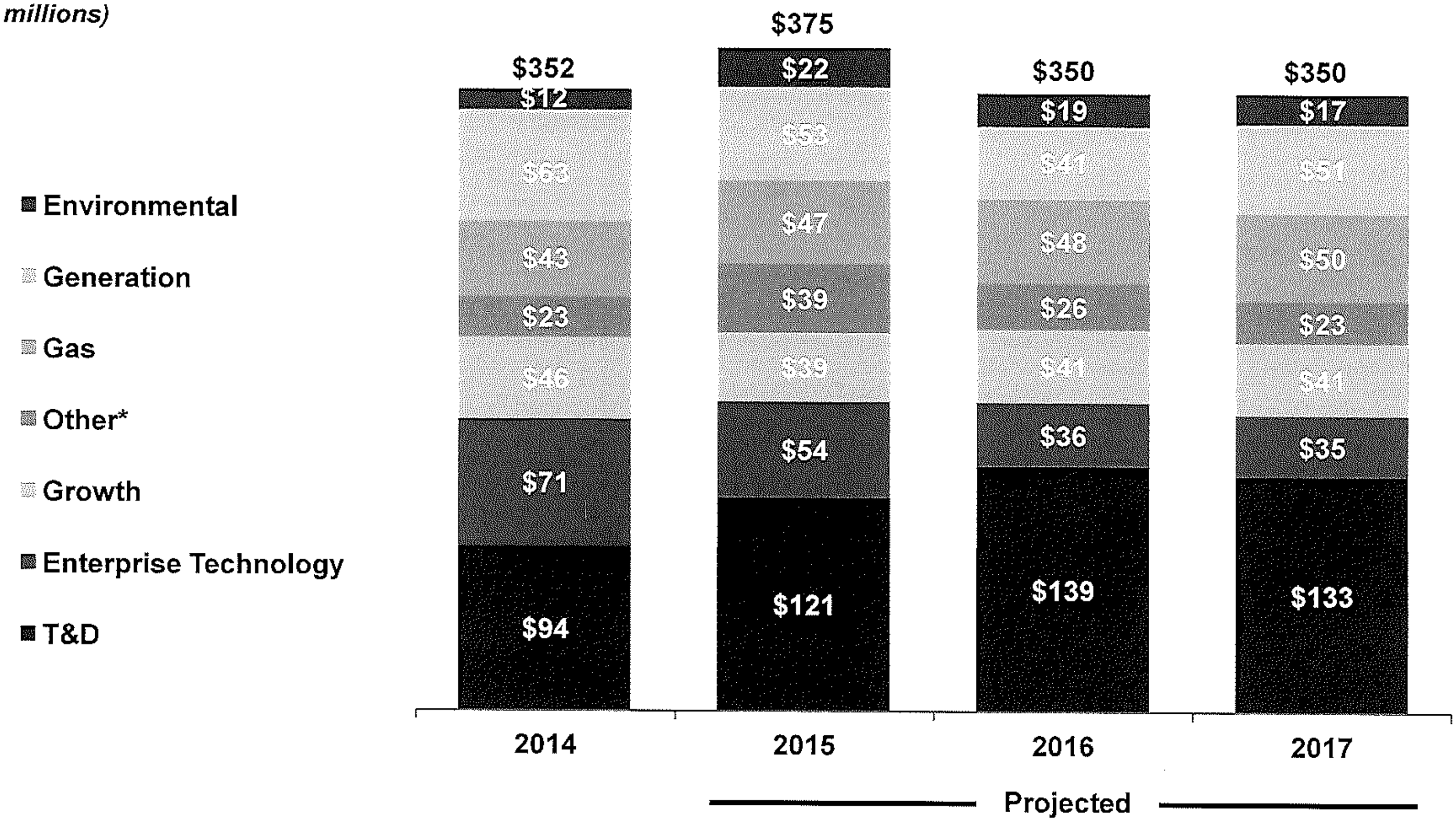
Significant investments in utility infrastructure

AVISTA

Significant investments to upgrade all systems

5% to 6% rate base growth

Avista Utilities Capital Expenditures**
($ millions)

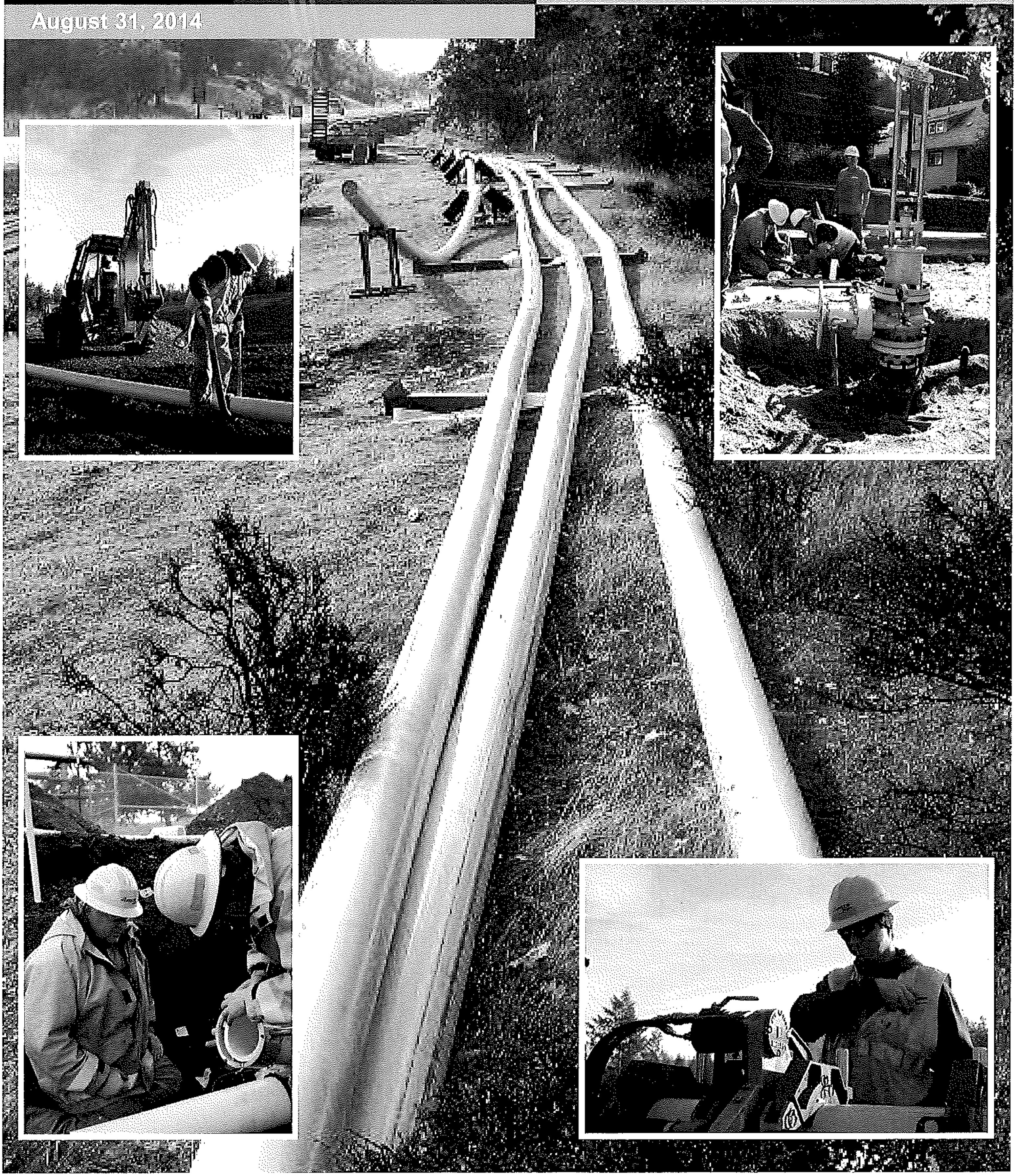


* Other includes Facilities and Fleet
** Excludes planned capital expenditures at AEL&P of $15 million in 2015, 2016 and 2017

AVISTA

2014 Natural Gas Integrated Resource Plan

August 31, 2014



Compressors can be a cost effective option to resolving system constraints; however, regulatory and environmental approvals to install a station, along with engineering and construction time can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure. Based on Avista's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

Conservation Resources

Included in the evaluation of distribution system constraints is the consideration of targeted conservation resources to reduce or delay distribution system enhancements. The consumer is still the ultimate decision-maker regarding the purchase of a conservation measure. Because of this, Avista attempts to influence conservation through the DSM measures discussed in Chapter 3 – Demand-Side Resources, but does not depend on estimates of peak day demand reductions from conservation to eliminate near-term distribution system constraints. Over longer-term, targeted conservation programs provide a cumulative benefit that offsets potential constraint areas and may be an effective strategy.

Planning Results

Table 7.1 summarizes the cost of major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of these expenditures. These projects are preliminary estimates of timing and costs of major reinforcement solutions. The scope and needs of these projects generally evolves with new information requiring ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions from the initial assessment.

The following discussion provides information about key near-term projects:

East Medford Reinforcement: Previous IRP and distribution planning analysis identified a near-term resource deficiency driven by forecasted local growth. Increased natural gas deliveries from the TransCanada Pipeline source at Phoenix Road Gate Station in southeast Medford will remedy this deficiency. To facilitate distribution receipt of the increased natural gas volumes, a new high-pressure (HP) line encircling Medford to the east and tying into an existing high-pressure line in White City will improve delivery capacity and provide reinforcement in the East Medford area.

This has been a multi-phase project spanning several years. As forecasted, needs have changed over time, and with no immediate resource need, completing the final phase of the project has been delayed. Other factors may drive completion of the project including reliability needs, flexibility of natural gas supply management and optimizing synergies of other construction projects to reduce project cost. Avista will continue to evaluate forecasts and assess the most appropriate timing for completion of this project.

U.S. Highway 2 North Spokane Reinforcement: This project will reinforce the area north of Spokane along U.S. Highway 2. This mixed-use area experiences low pressure during winter at unpredictable times given 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 gas main will be installed in a newly established easement along U.S. Highway 2.

Chase Road Gate Station, Post Falls, Idaho: This gate station will allow Avista to split the large load at the Rathdrum Gate Station. Approximately 18,000 feet of new HP line will connect the Chase Road Gate Station to the existing HP line. This gate station will give Avista the opportunity to feed the growing Post Falls and Coeur d'Alene areas from the north.

Table 7.1 Distribution Planning Capital Projects

		2015	2016	2017	2018
Projects	*East Medford Reinforcement	$0	$0	$0	$5,000,000
	Goldendale HP	$3,500,000	$0	$0	$0
	NSC Greene ST HP	$0	$0	$0	$1,500,000
	Rathdrum Prairie HP Gas Reinforcement	$100,000	$4,900,000	$5,000,000	$0
	*Reinforcement, Hwy 2 Kaiser	$1,300,000	$0	$0	$0
	Spokane St Bridge Gas	$1,000,000	$0	$0	$0

*Details of project described in IRP

Table 7.2 shows city gate stations identified as over utilized or under capacity. Estimated cost, year and the plan to remediate the capacity concern are shown.

Staff recommends the Commission direct Avista, in future IRPs, to provide a discussion of Avista's hedging strategies as to their impact on customer rates, how hedge prices compare with prevailing spot market prices, and any action taken by Avista to protect its customers from unnecessary losses associated with its hedging strategies. In addition, Staff recommends the Commission direct Avista, in future IRPs, to provide a discussion of procurement plans and risk management that is of sufficient detail to allow Staff to do a thorough review of the purchasing, hedging and risk management plans/policies/strategies.

Distribution Planning

Avista's IRP presents a discussion of distribution system planning. While the discussion is informative, Staff finds it is missing a clear presentation of how Avista decides which distribution system projects to include in the IRP, and a clear description of the included projects, along with a justification for recommending or proceeding with the projects.

Parties' Positions
CUB
CUB's January 26, 2015, reply comments express agreement with Staff's comments related to distribution planning.

Avista's Position
Avista states in its response comments that, in future IRPs, Avista will work to enhance the distribution planning discussion "to more clearly state the information" within the discussion, "and also to provide a more detailed description of the projects themselves."

Staff Position and Recommendation

Staff recommends the Commission direct Avista, in future IRPs, to include a clear presentation of how Avista decides which distribution system projects to include in the IRP, and a clear description of the included projects, along with a justification for recommending or proceeding with the projects.

Climate Change Regulation

Staff, in its comments, expressed concern that all of the climate change regulatory implications, beyond simply the immediate regulatory effects of the Environmental Protection Agency's proposed rules under Section 111 (d) of the federal Clean Air Act, are not currently accounted for in the planning period.

AVISTA

Capital Program Business Case

Investment Name:	Technology Refresh to Sustain Business Proce		
Requested Amount	$ 15,362,243	Assessments:	
Duration/Timeframe	10 Year Program	Financial:	Medium - >= 5% & <9% CIRR
Dept., Area:	IS/IT	Strategic:	Life Cycle Programs
Owner:	Jacob Reidt/Jim Corder	Operational:	Operations require execution to perform at current levels
Sponsor:	Jim Kensok	Business Risk:	ERM Reduction >5 and <= 10
Category:	Program	Program Risk:	High certainty around cost, schedule and resources
Mandate/Reg. Reference:	n/a	Assessment Score:	89

Recommend Program Description:	Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
		Annual Cost Summary - Increase/(Decrease)			
This program is in place to provide for technology refresh in allignment with the roadmaps for application and technology lifecycles. The continuation of technology refresh programs provides benefit to Avista by providing a stable and reliable application and computing platform to allow for the safe and reliable operation of our electric and gas infrastructures.	This program provides for current technologies for the normal operation of the business	$ 15,362,243		$ -	15

Alternatives:		Performance	Capital Cost	O&M Cost	Other Costs	Business Risk Score
			Annual Cost Summary - Increase/(Decrease)			
Unfunded Program:	Not doing this program will result in four major impacts: 1) Reduction of 62 staff members with key institutional knowledge 2) Decrease in business process efficiency 3) Increase in O&M labor to support the technology 4) Increase technology outages impacting the operations of the business.	The performance of the computing technology at	$ -		$ 1,895,751	20
Technology Refresh Programs	This program is in place to provide for technology refresh in allignment with the roadmaps for application and technology lifecycles. The continuation of technology refresh programs provides benefit to Avista by providing a stable and reliable application and computing platform to allow for the safe and reliable operation of our electric and gas infrastructures.	This program provides for current technologies for the normal	$ 15,362,243	$ -	$ -	15
Alternative 2: Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0
Alternative 3 Name : Brief name of alternative (if applicable)	Describe other options that were considered	describe any incremental changes in operations	$ -	$ -	$ -	0

Program Cash Flows

5 years of costs

	Capital Cost	O&M Cost	Other Costs	Approved
	$ 9,973,758	$ -		$ 9,973,758
2013	$ 10,019,774	$ -	$ -	$ 11,110,491
2014	$ 12,129,043	$ -	$ -	$ 15,362,243
2015	$ 13,949,536	$ -	$ -	$ 16,094,833
2016	$ 17,183,753	$ -	$ -	$ 16,094,833
2017	$ 19,031,035	$ -	$ -	$ 16,094,833
2018	$ -	$ -	$ -	$ 18,094,833
2019	$ -	$ -	$ -	$ 20,094,833
Total	$ 72,313,141	$ -	$ -	$ 102,825,824

Associated Ers (list all applicable):

5005

Mandate Excerpt (If applicable):

provide brief citation of the law or regulation and a reference number if possible

Additional Justifications:

Technology refresh program costs increase year over year to two main reasons. The first is because of the continuous technological evolution which causes oblolecence. Manufactures continue to upgrade and improve their systems to provide improved performance and function. This in turn requires companies to replace system on a periodic basis to maintain reliability and functionality. The second main reason is due to the addition of new hardware and software to support new business requirements and growth. New equipment purchased under Technology Expansion Program will have to be refreshed in 3-5 years adding to the refresh budget. For example, Infrastructure refresh costs the increase from year to year due to prior years spend in Technology Expansion, roughly $800k in Distributed Systems and $500k in Network Systems per year. Business Application Expansion is up between 2011 & 2012 because of the inclusion of some small to medium projects into the expansion program.

Resources Requirements: *(request forms and approvals attached)*

Internal Labor Availability: ☐ Low Probability ☐ Medium Probability ☑ High Probability
Contract Labor: ☑ YES ☐ NO

Enterprise Tech: ☑ YES - attach form ☐ NO or Not Required
Facilities: ☑ YES - attach form ☐ NO or Not Required
Capital Tools: ☐ YES - attach form ☑ NO or Not Required
Fleet: ☐ YES - attach form ☑ NO or Not Required

Check the appropriate box. The internal and contract labor boxes should be checked to indicate if the resource owners have been contacted and to provide a general sense of how likely staff will be provided (this does not require a firm committment).

Printed: 11/05/2014

CASE: UG 288
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 605

Confidential Exhibits in Support
Of Opening Testimony

October 16, 2015

STAFF EXHIBIT 605

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

CASE: UG 288
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Gas Storage in Rate Base, Underground Storage Operating Expenses, Other Gas Expense, Purchased Gas Expense, Integrated Resource Plan

Opening Testimony

October 16, 2015

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

A. My name is Erik Colville. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I present Staff's recommendations regarding the rate treatment of gas storage in rate base, "underground storage operating expense,""other gas supply expense," "purchased gas expense," and the Integrated Resource Plan (IRP).

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/701 Witness Qualification Statement, consisting of one page, Exhibit Staff/702 Data Request Responses, and Exhibit Staff/703 Other Gas Supply Expense, consisting of two pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize your recommendations regarding each of these issues.

A. Issue 1. Gas Storage in Rate Base – As a result of my analysis of the issue, I have no proposed adjustment at this time. I recommend the Commission adopt the amount of $3,078,000 for Gas Storage in Rate Base, as requested by Avista.

Issue 2. Underground Storage--I recommend the Commission adopt the amount of $136,000 for “underground storage operating expense,” as requested by Avista.

Issue 3. Other Gas Expense – I propose to reduce Avista’s requested “other gas expense” by $80,000, from $550,000 to $470,000.

Issue 4. Purchased Gas Expense – The actual cost of gas is reconciled with customers each year in the Purchased Gas Adjustment (Order No. 14-238 in Docket No. UM 1286). Therefore, I have no proposed adjustment for “purchased gas expense” in this rate case at this time.

Issue 5. IRP - The IRP does not identify a need for new resources within the 20-year planning period. There is no connection made in the presentation to the rate case.

ISSUE 1. GAS STORAGE IN RATE BASE

Q. Please describe the gas storage costs at issue.

A. Storage gas consists of two components, "cushion gas" and "working gas inventory." Cushion gas is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir. "Working gas inventory" is the gas that flows in and out of the storage reservoir (or Liquid Natural Gas (LNG) tank) to serve customer loads.

Q. Please summarize Avista's and your proposed rate treatment of Avista's gas storage costs.

A. Avista includes $3,078,000 for gas storage in its rate base. Avista/501 Smith/4-11, lines 247-250. This amount is the 2014 end-of-year balance for Avista's working gas inventory. I support including the cost of working gas inventory in rate base. I do not recommend an adjustment to the amount included in rate base as proposed by Avista. I do propose the cost of working gas inventory in rate base to be based on the average of monthly working gas inventories for 2014, rather than the end-of-year amount.

Q. Please summarize the Commission's historical treatment of gas storage in rate base.

A. Few orders[1] expressly address the appropriate regulatory treatment of working gas inventory costs, but all three gas utilities in Oregon currently include these

[1] See *Order No. 77-125 and* Order No. 13-349.

costs in rate base.[2] In 1977, the Commission expressly allowed Cascade to include its gas storage costs as an asset in rate base.[3]

Q. Did Staff oppose inclusion of working gas inventory in rate base in NW Natural's last general rate case (Docket No. UG 221)?

A. Yes. Staff recommended that NW Natural recover a return on its working gas inventory through the Purchased Gas Adjustment (PGA), which would allow the Commission to annually update the working gas inventory. Staff, NW Natural, and other parties entered into a stipulation in UG 221 under which the working gas inventory issue was moved to a separate docket, Docket No. UM 1651. In that docket, Staff, NW Natural and other parties stipulated to the inclusion of working gas inventory in NW Natural's rate base and the Commission adopted the Stipulation.[4]

Q. Does Staff still believe it is preferable to allow a utility to recover a return on its working gas inventory through its PGA?

A. No. Staff is persuaded that the benefit obtained by updating the level of working gas inventory each year does not warrant introducing a complicated adjustment into the PGA mechanism.

Q. Please summarize your analysis of the amount that should be included in rate base for working gas inventory.

A. Staff's analysis in Docket No. UM 1651 showed that year-to-year variations in average annual gas storage are caused by variations in weather from that

[2] See e.g., Order No. 13-349 (Commission adopting stipulation including NW Natural Gas Company's working gas inventory in rate base).
[3] Re Cascade Natural Gas Corporation, Order No. 77-125 (1977 WL 440903 at 3).
[4] Order No. 13-049.

forecasted and spot market gas prices falling below the average cost of gas in storage. Staff's analysis also showed that the amount NW Natural could include in rate base should be calculated using NW Natural's forecasted average working gas inventory balances for the November 2013-October 2014 time period.

While it may be possible to recommend the amount of storage gas in rate base based upon historical data and forecasting models, historical treatment of the issue has been to use the most recent or forecasted 12-month average to calculate the amount to include in rate base. I therefore recommend that the amount of gas storage in rate base be based upon a recent 12-month average.

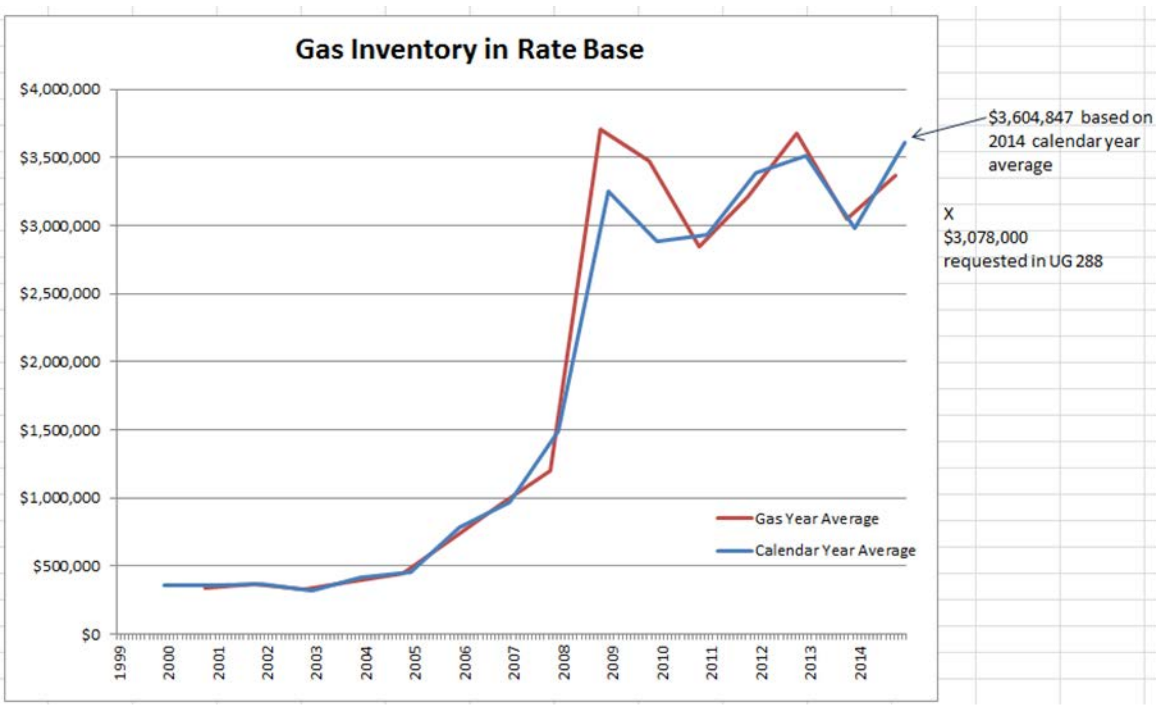
Q. Did you issue data requests to Avista about the working gas inventory issue?

A. Yes. Staff Data Requests (DR) Nos. DR 124 and 125 were issued to Avista requesting monthly storage inventory levels as well as the monthly storage guideline for each storage facility. Based upon Avista's responses to DR Nos. 124 and 125, cushion gas is valued in this rate case at its cost when placed in the reservoir. Refer to Exhibit Staff/702 for DR responses.

Q. Please explain how Avista's responses to your DRs affected your analysis.

A. As a result of Avista's responses, my analysis primarily deals with working gas. Avista's response to DR Nos. 124 and 125 did not include a forecast of working gas in storage for 2015. In addition, Avista's rate case uses the 2014 Results of Operations (ROO) as its base year. For these two reasons, for the amount of

Gas Storage in Rate Base, I propose to use the 2014 calendar year average instead of using the current forecast gas year (Nov 2014-Oct 2015) average. Using data provided in Avista's response to DRs 124 and 125 to calculate the annual averages, the historic calendar year and historic gas year averages are depicted in the figure below. Based upon the 2014 calendar year average gas storage, an amount up to $3,604,847 could be justified.



Q. Please describe your proposed adjustment to Gas Storage in Rate Base.

A. As a result of my analysis of the issue, I have no proposed adjustment at this time. I propose to allow the amount of $3,078,000 for Gas Storage in Rate Base, as requested by Avista.

ISSUE 2. UNDERGROUND STORAGE OPERATING EXPENSE

Q. What is "underground storage operating expense?"

A. "Underground storage operating expense" is expense recorded in FERC Accounts 814, 824, and 837 and includes: the cost of labor and expenses incurred in the general supervision and direction of underground storage operations; the cost of labor, material used and expenses incurred in operating underground storage plant, and other underground storage operating expenses, not includible in any of the foregoing accounts, including research, development, and demonstration expenses; and the cost of labor, materials used and expenses incurred in the maintenance of equipment, the book cost of which is includible in Account 357, Other Equipment.[5]

Q. Please summarize Avista's proposal related to "underground storage operating expense."

A. Avista proposes to begin with the Total Underground Storage Operating Expense from its 2014 Results Of Operation (ROO), and to apply adjustments, which results in a Restated 2016 average of monthly averages (AMA) Test Period Total Underground Storage Operating Expense of $136,000. Avista/501, Smith/4-11, line 45.

Q. Please summarize the Commission's historical treatment of "underground storage operating expense."

[5] See 18 C.F.R. FERC Accounts 814, 824, and 837.

A. I was not able to find a Commission order expressly addressing how to determine the proper amount of “underground storage operating expense” that should be included in revenue requirement.

Q. What is your recommendation?

A. Staff practice is a general preference for considering the previous three year’s expense results more heavily than a long-term trend, unless there is a reason not to do so. Thus, I conclude that using the adjusted ROO expense is not the optimum way to calculate the appropriate amount to include in revenue requirement. Accordingly, my recommendation is based on review of Avista’s actual “underground storage operating expense” for the previous three years.

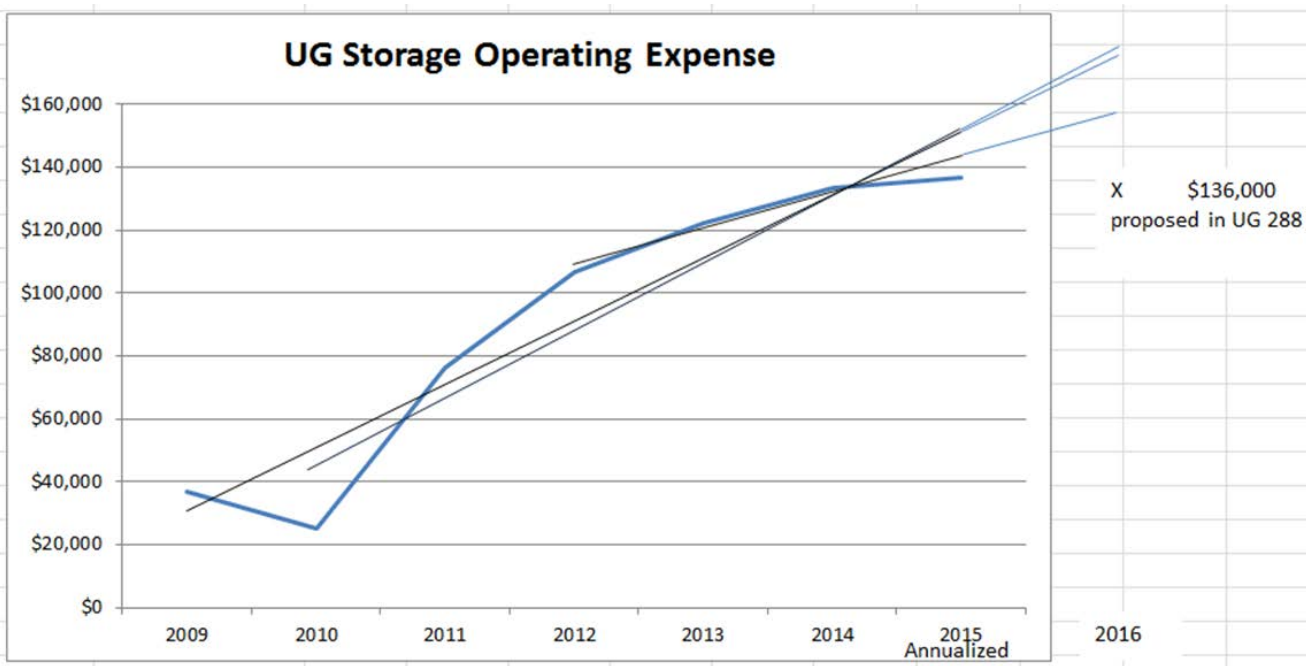
Q. Please summarize your analysis.

A. No detail was provided initially for supervision and engineering, other expenses, or other equipment. Staff issued DR 123 seeking 10-year historical “underground storage operating expense” results, as well as a breakdown of “underground storage operating expense” into supervision and engineering, other expenses, and other equipment categories. The breakdown provided in response to DR 123 is shown in the following table and on the following figure. Refer to Exhibit Staff/702 for DR response.

Q. Please explain how to understand the following table and figure.

A. The 2015 amount represents four months ended 4/30/15. Supervision and engineering was $0 in each year, so that detail is omitted. In addition, there were no Oregon ratepayer expenses for storage prior to 2009, thus there is no detail prior to 2009.

	OR Only	2009	2010	2011	2012	2013	2014	Annualized 2015	Jan-15	Feb-15	Mar-15	Apr-15
824000	NAT GAS STORAGE - OTHER EXPENSES	19,152	12,048	39,772	57,988	67,117	69,813	74,035	7,022	7,165	4,751	5,741
837000	NAT GAS STORAGE - OTHER EQUIPMENT	17,674	13,041	36,225	48,707	54,844	63,795	62,794	3,776	6,020	5,142	5,993
Total		$36,826	$25,089	$75,997	$106,695	$121,961	$133,608	$136,829	10,798	13,185	9,893	11,733



Q. Please continue with explaining your analysis.

A. Based upon Avista's responses to DRs 208 and 209, the dip in "underground storage operating expense" for 2010 reflects increasing Oregon's share of Jackson Prairie operating and maintenance expenses from 3.08 percent to 9.65 percent, corresponding with the increase in capacity for Oregon customers. This increase in allocation percentage is the primary reason for the increase in expenses between 2010 and 2011. In addition, there is a timing lag associated with invoice processing and expense recognition because Avista is not the operating partner for Jackson Prairie. For example, $46,000 of costs incurred in 2010 were expensed in 2011. Refer to Exhibit Staff/702 for DR responses.

Q. What conclusions do your draw from this information?

A. All the trend lines through the historical “underground storage operating expense” data indicate justification for an amount greater than that requested by Avista. Given recent “underground storage operating expenses,” Avista’s proposed $136,000 appears to have a reasonable basis.

Q. Please summarize your proposed adjustment to “underground storage operating expense.”

A I have no proposed adjustment at this time. I propose to allow $136,000 for “underground storage operating expense,” as requested by Avista.

ISSUE 3. OTHER GAS EXPENSE

Q. What is "other gas expense?"

A. "Other gas expense" is expense recorded in FERC Account 813, and includes the cost of labor, materials used and expenses incurred in connection with gas supply functions, including, research and development expenses, not provided for in any other FERC account for gas expense.[6]

Q. Please summarize Avista's proposal related to other gas expense.

A. Avista proposes to begin with the Total Other Gas Supply Expense from its 2014 ROO, to apply adjustments, which results in a Restated 2016 AMA Test Period Total Other Gas Supply Expense of $550,000. Avista/501, Smith/4-11, line 37.

Q. Please summarize Commission historical treatment of "other gas expense."

A. I was not able to find a Commission order expressly addressing how to determine the proper amount of "other gas expense" that should be included in revenue requirement.

Q. What is your recommendation?

A. As stated previously, Staff's practice is to consider the previous three year's expense results more heavily than a long term trend, unless there is a reason not to do so. Thus, I conclude that using the adjusted ROO expense is not the optimum way to calculate the appropriate amount to include in revenue

[6] See 18 C.F.R. FERC Account 813.

requirement. Accordingly, my recommendation is based on review of Avista's actual "other gas expense" for the previous three years.

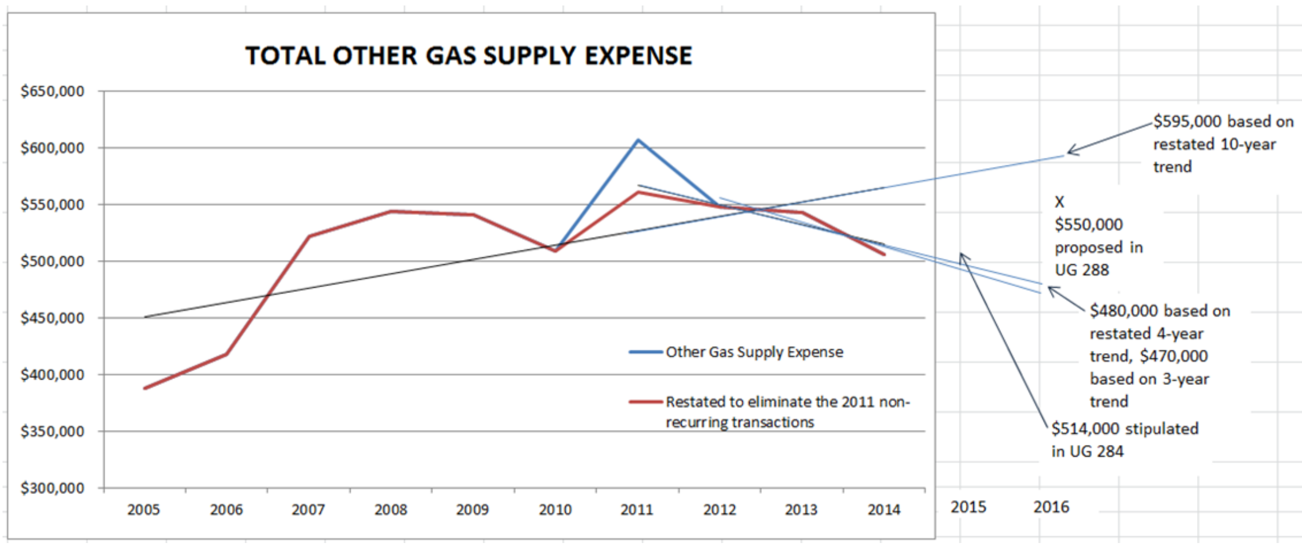
Q. Please summarize your analysis.

A. The "other gas expense" amount in this rate case, $550,000, is consistent with that requested in the last rate case (Docket No. UG 284), $574,000, just one year ago.

I issued DR 122 seeking 10-year historical "other gas expense" results, as well as a breakdown of the "other gas expense" into Other Gas Purchases, Purchased Gas Expenses, Natural Gas Storage Transactions, Gas Used for Products Extraction, Other Gas Expenses, and Gas Technology Institute Expense categories. Of these six expense subcategories, only Other Gas Expenses, and Gas Technology Institute (GTI) Expenses remain after the various rate case adjustments. Refer to Exhibit Staff/702 for DR response.

Q. What was Avista's response to your DR 122?

A. Avista's response to DR 122 is depicted in the figure below, and in Exhibit Staff/703. For the period of 2011 through 2014, there is a downward trend for the "other gas expense." Without a reason to discount the downward trend, Staff's analysis approach is to set the "other gas expense" for 2016 so that it lies on the 3-year trend line which begins in 2012. The resulting "other gas expense" I propose for 2016 is $470,000, as depicted below, and in Exhibit Staff/703.



Q. Please summarize your proposed adjustment to "other gas expense."

A. I propose to reduce Avista's requested "other gas expense" by $80,000, from $550,000 to $470,000.

ISSUE 4. PURCHASED GAS EXPENSE

Q. Please describe your proposed adjustment of "purchased gas expense."

A. The actual cost of gas is reconciled with customers each year in the Purchased Gas Adjustment (Order No. 14-238 in Docket No. UM 1286). Therefore, I have no proposed adjustment for "purchased gas expense" in this rate case at this time.

ISSUE 5. IRP

Q. Does Avista make a proposal related to its IRP in this rate case?

A. No.

Q. Do you have an IRP related concern?

A. No. Avista/400, Moorehouse/11-12 presents that Avista filed its 2014 IRP on August 29, 2014 and that the IRP does not identify a need for new resources within the 20-year planning period. There is no connection made in the presentation to the rate case.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME: Erik E. Colville, P.E.

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Resources and Planning Division

ADDRESS: 201 High St. SE., Suite 100
SALEM, OR. 97301

EDUCATION: Bachelor of Science in Agricultural Engineering
Washington State University, Pullman, WA, 1979

Master of Business Administration
City University, Seattle, WA, 1989

Licensed Professional Engineer since 1984, and licensed as such in Oregon since 1997

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since June of 2010. I am a Senior Utility Analyst in the Energy Resources and Planning Division of the Utility Program. Current responsibilities include lead analyst for integrated resource planning and resource acquisition, analyst for rate case elements, and other regulated utility matters.

I have approximately 36 years of professional engineering experience, including approximately 23 years:

- Relating to air, water and soil environmental issues; and
- Evaluating, planning, permitting, designing, and supporting construction of energy facilities

CASE: UG 288
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 122	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

Please provide, in a single electronic spreadsheet format with cell references and formulae intact, for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015, the other gas supply expense results, as well as a breakdown of the other gas supply expense into other gas purchases, purchased gas expenses, natural gas storage transactions, gas used for products extraction, other gas expenses, and Gas Technology Institute categories. Separately identify any related labor expense for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015. Provide results separately for total company and for Oregon. This request relates to Avista/501, Smith/4 at line 37, and Avista/502, Smith/1 at lines 30 through 37.

RESPONSE:

Please see Staff_DR_122 Attachment A for a breakdown of Other Gas Supply expenses included in this case. Per discussion with Staff, those accounts which are included in the Company's Purchase Gas Cost Adjustment (PGA) have been eliminated from the attachment (ie other gas purchases, purchased gas expenses, natural gas storage transactions, and gas used for products extraction.)

Other Gas Supply Expense
Calendar Years 2005-2014

Acct	Description	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	(a) 12/31/2011	12/31/2012	12/31/2013	(b) 12/31/2014*
813010	GTI	$ -	$ -	$ -	$ -	$ -	$ 11,959	$ 47,508	$ 43,989	$ 47,751	$ 40,632
	GTI	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 11,959**	**$ 47,508**	**$ 43,989**	**$ 47,751**	**$ 40,632**
813000	OTHER EXPENSE - Labor	$ 387,728	$ 186,588	$ 191,991	$ 239,623	$ 252,767	$ 254,295	$ 268,009	$ 237,604	$ 225,823	$ 229,743
813000	OTHER EXPENSE - Non Labor	not avail	$ 231,149	$ 329,765	$ 304,732	$ 288,507	$ 243,023	$ 291,882	$ 266,410	$ 269,970	$ 235,939
	OTHER EXPENSE	**$ 387,728**	**$ 417,737**	**$ 521,756**	**$ 544,355**	**$ 541,274**	**$ 497,318**	**$ 559,891**	**$ 504,014**	**$ 495,793**	**$ 465,681**
	TOTAL	$ 387,728	$ 417,737	$ 521,756	$ 544,355	$ 541,274	$ 509,277	$ 607,399	$ 548,003	$ 543,544	$ 506,313

* Total amount ties to 2014 Restated Historical AMA Base Test Year and excludes all PGA Accounts.

(a) 2011 included two non-recurring transactions.

1	Encana Gas Reserve Write Off	$ 26,000	The Company elected not to move forward with the Encana Gas Reserve Deals and wrote off expenses accrued for this purpose.
2	Labor Back-fill	$ 20,000	
	Total	$ 46,000	

(b) Reduction in non-labor expense from 2013 to 2014 is due to the change in Labor Loading Rates from 63% (Dec. 2013) to 39% (Dec 2014). This is due to various actuarial assumptions for Pension and Medical regarding the discount rate and expected return on assets. Please see Staff_DR_059C Confidential Attachment A for year over year comparison.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 123	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

Please provide, in a single electronic spreadsheet format with cell references and formulae intact, for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015, the underground storage operating expense results, including a breakdown of the underground storage operating expense into supervision and engineering, other expenses, and other equipment categories. Separately identify any related labor expense for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015. Provide results separately for total company and for Oregon. This request relates to Avista/501, Smith/4 at line 45, and Avista/502, Smith/1 at lines 41 through 45

RESPONSE:

Please see Staff_DR_123 Attachment A for yearly values for Jackson Prairie operating expenses for 2009-2013 yearly and monthly values for 2015. Puget Sound Energy is the operating partner for the facility and maintains individual expense account details. The Company records all expenses at a summary level into general ledger account 824000 Natural Gas Storage – Other Gas Supply and 837000 Natural Gas Storage – Other Equipment.

Oregon customers were assigned a portion of the Jackson Prairie facility effective November 1, 2008 with the first O & M charges being incurred January 2009. Prior to this time, Oregon customers' participation in the facility was contracted under Northwest Pipeline SGS-2 rate schedule and flowed through demand costs in the PGA. There are no labor expenses included in the provided values.

STATE OF OREGON
JACKSON PRAIRIE
OPERATING EXPENSES

	OR Only	2009	2010	2011	2012	2013	2014	Jan-15	Feb-15	Mar-15	Apr-15
824000	NAT GAS STORAGE - OTHER EXPENSES	19,152	12,048	39,772	57,988	67,117	69,813	7,022	7,165	4,751	5,741
837000	NAT GAS STORAGE - OTHER EQUIPMENT	17,674	13,041	36,225	48,707	54,844	63,795	3,776	6,020	5,142	5,993
Total		36,826	25,089	75,997	106,695	121,961	133,608	10,798	13,185	9,893	11,733

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 124	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

Please provide, in a single electronic spreadsheet format with cell references and formulae intact, the monthly historical working gas inventory balances (excluding labor dollars) for each storage facility (in both volume and in dollars) and the monthly working gas storage guideline, or goal or target, for each storage facility (in the same volume units as used for the inventory). Provide the monthly data requested above from the first date each storage facility was placed in operation through 2013, and to the extent as available monthly through 2014. Please identify whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2004 through 2013, and to the extent as available monthly through 2014. This request relates to Avista/601, Andrews/4 at line 242, and Avista/602, Andrews/5 at lines 236 through 240.

RESPONSE:

Please see Staff_DR_124 Attachment A for Storage detail for 09/1999-12/2006.
Please see Staff_DR_124 Attachment B for Storage detail for 01/2007-12/2008.
Please see Staff_DR_124 Attachment C for Storage detail for 01/2008-04/2015.

Data is provided in electronic format as requested. The accounting department maintains spreadsheets in individually grouped workbooks (for instance 09/1999-12/2006) for prior periods. Data is provided for end of month values in the format that is readily available. No labor dollars are included in working gas inventory. Avista injects gas yearly in accordance with operating procedures which require 35% of the facility be full by June 30, 80% by August 31, and 100% by September 30.

Oregon Jackson Prairie Inventory/Prepaid Gas									
Account 164100 GD OR			Contract 100403		GL Account changed to 164105 effective 7/01/2007				
Dekatherms									
	Injected Volumes	Withdrawal Volumes	Volume Adjustments	Volume Balance	Injected Value	Withdrawal Value	Cost Adjustments	Balance	WACOG
Balance				93,736				$ 187,093.20	$1.9960
Adjustment to Beginning Balance			(13,736)	80,000			$ (27,417.06)	$ 159,676.14	$1.9960
Sep-99	-	-		80,000	$ -	$ -		$ 159,676.14	$1.9960
Oct-99	-	-		80,000	$ -	$ -		$ 159,676.14	$1.9960
Nov-99	-	-		80,000	$ -	$ -		$ 159,676.14	$1.9960
Dec-99	-	(20,000)		60,000	$ -	$ (39,920.00)		$ 119,756.14	$1.9960
Jan-00	-	(20,000)		40,000		$ (39,920.00)		$ 79,836.14	$1.9960
Feb-00	-	(20,000)		20,000		$ (39,920.00)		$ 39,916.14	$1.9960
Mar-00	-	(20,000)		-		$ (39,916.14)		$ -	
Apr-00	-	-		-		$ -		$ -	
May-00	20,000	-		20,000	$ 56,550.74	$ -		$ 56,550.74	$2.8275
Jun-00	20,000	-		40,000	$ 71,035.31	$ -		$ 127,586.05	$3.1897
Jul-00	20,000	-		60,000	$ 79,608.41	$ -		$ 207,194.46	$3.4532
Aug-00	20,000	-		80,000	$ 65,802.05	$ -		$ 272,996.51	$3.4125
Sep-00	-	-		80,000		$ -		$ 272,996.51	$3.4125
Oct-00	-	-		80,000		$ -		$ 272,996.51	$3.4125
Nov-00	-	-		80,000		$ -		$ 272,996.51	$3.4125
Dec-00	-	(20,000)		60,000		$ (68,250.00)		$ 204,746.51	$3.4124
Jan-01	-	(20,000)		40,000		$ (68,248.00)		$ 136,498.51	$3.4125
Feb-01	-	(20,000)		20,000		$ (68,250.00)		$ 68,248.51	$3.4124
Mar-01	-	(20,000)		-		$ (68,248.51)		$ -	#DIV/0!
Apr-01	-	-		-		$ -		$ -	#DIV/0!
May-01	20,000	-		20,000	$ 97,763.11	$ -		$ 97,763.11	$4.8882
Jun-01	20,000	-		40,000	$ 73,056.63	$ -		$ 170,819.74	$4.2705
Jul-01	20,000	-		60,000	$ 55,327.99	$ -		$ 226,147.73	$3.7691
Aug-01	20,000	-		80,000	$ 49,998.37	$ -		$ 276,146.10	$3.4518
Sep-01		-		80,000		$ -		$ 276,146.10	$3.4518
Oct-01		-		80,000		$ -		$ 276,146.10	$3.4518
Nov-01		-		80,000		$ -		$ 276,146.10	$3.4518
Dec-01		(20,000)		60,000		$ (69,036.00)		$ 207,110.10	$3.4518
Jan-02		(20,000)		40,000		$ (69,036.00)		$ 138,074.10	$3.4519
Feb-02		(20,000)		20,000		$ (69,038.00)		$ 69,036.10	$3.4518
Mar-02		(20,000)		-		$ (69,036.10)		$ -	#DIV/0!
Apr-02		-		-		$ -		$ -	#DIV/0!
May-02	20,000	-		20,000	$ 57,233.59	$ -		$ 57,233.59	$2.8617
Jun-02	20,000	-		40,000	$ 49,801.34	$ -		$ 107,034.93	$2.6759
Jul-02	20,000	-		60,000	$ 39,920.57	$ -		$ 146,955.50	$2.4493
Aug-02	20,000	-		80,000	$ 36,571.96	$ -		$ 183,527.46	$2.2941
Sep-02	-	-		80,000		$ -		$ 183,527.46	$2.2941
Oct-02	-	-		80,000		$ -		$ 183,527.46	$2.2941
Nov-02	-	-		80,000		$ -		$ 183,527.46	$2.2941
Dec-02	-	(20,000)		60,000		$ (45,882.00)		$ 137,645.46	$2.2941
Jan-03	-	(20,000)		40,000		$ (45,882.00)		$ 91,763.46	$2.2941
Feb-03	-	(20,000)		20,000		$ (45,882.00)		$ 45,881.46	$2.2941
Mar-03	-	(20,000)		-		$ (45,881.46)		$ -	#DIV/0!
Apr-03	-			-		#DIV/0!		$ -	#DIV/0!
May-03	20,000			20,000	$ 95,948.81			$ 95,948.81	$4.7974
Jun-03	20,000			40,000	$ 95,646.54			$ 191,595.35	$4.7899
Jul-03	20,000			60,000	$ 101,777.20			$ 293,372.55	$4.8895
Aug-03	20,000			80,000	$ 84,310.86			$ 377,683.41	$4.7210
Sep-03				80,000	$ 420.37			$ 378,103.78	$4.7263
Oct-03				80,000				$ 378,103.78	$4.7263
Nov-03				80,000				$ 378,103.78	$4.7263
Dec-03		(20,000)		60,000		$ (94,526.00)		$ 283,577.78	$4.7263
Jan-04		(20,000)		40,000		$ (94,500.00)		$ 189,077.78	$4.7269
Feb-04		(20,000)		20,000		$ (94,500.00)		$ 94,577.78	$4.7289
Mar-04		(20,000)		-		$ (94,577.78)		$ -	#DIV/0!
Apr-04		-		-		$ -		$ -	#DIV/0!
May-04	20,000	-		20,000	$ 101,550.79			$ 101,550.79	$5.0775
Jun-04	20,000	-		40,000	$ 113,018.43			$ 214,569.22	$5.3642
Jul-04	20,000	-		60,000	$ 107,747.71			$ 322,316.93	$5.3719
Aug-04	20,000	-		80,000	$ 108,112.60			$ 430,429.53	$5.3804
Sep-04	-	-		80,000				$ 430,429.53	$5.3804
Oct-04	-	-		80,000				$ 430,429.53	$5.3804
Nov-04	-	-		80,000				$ 430,429.53	$5.3804
Dec-04	-	(20,000)		60,000		$ (107,608.00)		$ 322,821.53	$5.3804

Oregon Jackson Prairie Inventory/Prepaid Gas									
Account 164100 GD OR			Contract 100403		GL Account changed to 164105 effective 7/01/2007				
Dekatherms									
	Injected Volumes	Withdrawal Volumes	Volume Adjustments	Volume Balance	Injected Value	Withdrawal Value	Cost Adjustments	Balance	WACOG
Jan-05	-	(20,000)		**40,000**		$ (107,608.00)		**$ 215,213.53**	**$5.3803**
Feb-05	-	(20,000)		**20,000**		$ (107,606.00)		**$ 107,607.53**	**$5.3804**
Mar-05	-	(20,000)		**-**		$ (107,607.53)		**$ -**	**#DIV/0!**
Apr-05	-	-		**-**				**$ -**	**#DIV/0!**
May-05	-	-		**-**				**$ -**	**#DIV/0!**
Jun-05	42,295	-		**42,295**	$ 238,768.46			**$ 238,768.46**	**$5.6453**
Jul-05	32,546	-		**74,841**	$ 196,976.36		$ 1,062.16	**$ 436,806.98**	**$5.8365**
Aug-05	4,000	-		**78,841**	$ 25,737.81		$ 0.02	**$ 462,544.81**	**$5.8668**
Sep-05	3,602	-		**82,443**	$ 31,312.01		$ (66.42)	**$ 493,790.40**	**$5.9895**
Oct-05	-	-		**82,443**		$ -	$ (21.53)	**$ 493,768.87**	**$5.9892**
Nov-05	-	-		**82,443**				**$ 493,768.87**	**$5.9892**
Dec-05	-	-	13,122	**95,565**			$ 82,783.77	**$ 576,552.64**	**$6.0331**
Jan-06	-	(34,502)		**61,063**		$ (208,154.02)		**$ 368,398.62**	**$6.0331**
Feb-06	-	(41,018)		**20,045**		$ (247,465.70)		**$ 120,932.92**	**$6.0331**
Mar-06	-	(6,842)		**13,203**		$ (41,278.47)		**$ 79,654.45**	**$6.0331**
Apr-06	-			**13,203**		$ -		**$ 79,654.45**	**$6.0331**
May-06	27,324			**40,527**	$ 212,298.49	$ -		**$ 291,952.94**	**$7.2039**
Jun-06	29,434			**69,961**	$ 179,014.64	$ -		**$ 470,967.58**	**$6.7319**
Jul-06	25,604			**95,565**	$ 151,317.08	$ -		**$ 622,284.66**	**$6.5116**
Aug-06	-			**95,565**	$ -	$ -		**$ 622,284.66**	**$6.5116**
Sep-06	-			**95,565**	$ -	$ -		**$ 622,284.66**	**$6.5116**
Oct-06	-			**95,565**	$ -	$ -		**$ 622,284.66**	**$6.5116**
Nov-06	-			**95,565**	$ -	$ -		**$ 622,284.66**	**$6.5116**
Dec-06	-	(7,962)		**87,603**	$ -	$ (51,845.67)		**$ 570,438.99**	**$6.5116**

Oregon Plymouth Inventory/Prepaid Gas				Contract 100602					
Account 164200 GD OR									
Dekatherms									
	Injected Volumes	Withdrawal Volumes	Volume Adjustments	Volume Balance	Injected Value	Withdrawal Value	Cost Adjustments	Balance	WACOG
Balance				107,608				$ 204,356.85	$ 1.8991
Sep-99	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Oct-99	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Nov-99	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Dec-99	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jan-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Feb-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Mar-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Apr-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
May-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jun-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jul-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Aug-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Sep-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Oct-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Nov-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Dec-00	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jan-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Feb-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Mar-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Apr-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
May-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jun-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jul-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Aug-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Sep-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Oct-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Nov-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Dec-01	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jan-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Feb-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Mar-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Apr-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
May-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jun-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jul-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Aug-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Sep-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Oct-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Nov-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Dec-02	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jan-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Feb-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Mar-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Apr-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
May-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jun-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jul-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Aug-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Sep-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Oct-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Nov-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Dec-03	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jan-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Feb-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Mar-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Apr-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
May-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jun-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jul-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Aug-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Sep-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Oct-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Nov-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Dec-04	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Jan-05	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Feb-05	0	0		107,608	$ -	$ -		$ 204,356.85	$ 1.8991
Mar-05	64,792	0		172,400	$ 341,356.65	$ -		$ 545,713.50	$ 3.1654
Apr-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
May-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Jun-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Jul-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Aug-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654

Oregon Plymouth Inventory/Prepaid Gas				Contract 100602					
Account 164200 GD OR									
Dekatherms									
	Injected	Withdrawal	Volume	Volume	Injected	Withdrawal	Cost		
Sep-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Oct-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Nov-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Dec-05	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Jan-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Feb-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Mar-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Apr-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
May-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Jun-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Jul-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Aug-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Sep-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Oct-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Nov-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654
Dec-06	-	0		172,400	$ -	$ -		$ 545,713.50	$ 3.1654

Storage Leased - Account for fuel as a reduction of injection (808200). Priced at daily injection price. AVA leases from JP/NWP for OR and gets charged for fuel only on injections from NWP

Oregon Jackson Prairie Inventory/Prepaid Gas										
Account 164105 GD OR		Contract 100403								
Dekatherms										
GL Account	808200 GD OR	808100 GD OR	808200 GD OR		808200 GD OR	808100 GD OR	808100 GD OR	808200 GD OR	164105 GD OR	
	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Adjustments	Injection Fuel Value	Balance	Inventory WACOG
Balance Dec-06				87,603					$ 570,438.99	$ 6.51160
Jan-07	0	(50,368)	0	37,235	$0.00	($327,978.25)		$0.00	$ 242,460.74	$ 6.51164
Feb-07	0	(22,066)	0	15,169	$0.00	($143,685.75)		$0.00	$ 98,774.99	$ 6.51163
Mar-07	0	(8,350)	0	6,819	$0.00	($54,372.15)		$0.00	$ 44,402.84	$ 6.51164
Apr-07	0	(6,819)	0	-	$0.00	($44,402.84)		$0.00	$ -	$ 6.51164
May-07	15,198	0	(69)	15,129	$89,348.40	$0.00		($417.51)	$ 88,930.89	$ 5.87817
Jun-07	26,998	0	(120)	42,007	$131,954.63	$0.00		($653.60)	$ 220,231.92	$ 5.24274
Jul-07	27,957	0	(124)	69,840	$132,265.05	$0.00		($639.17)	$ 351,857.80	$ 5.03806
Aug-07	19,476	0	(93)	89,223	$81,626.66	$0.00		($461.20)	$ 433,023.26	$ 4.85327
Sep-07	6,366	0	(30)	95,559	$18,931.54	$0.00		($143.72)	$ 451,811.08	$ 4.72809
Oct-07	6	0	0	95,565	$23.62	$0.00		$0.00	$ 451,834.70	$ 4.72804
Nov-07	0	(1,500)	0	94,065	$0.00	($7,091.56)		$0.00	$ 444,743.14	$ 4.72804
Dec-07	0	(15,779)	0	78,286	$0.00	($7.13)		$0.00	$ 444,736.01	
YTD 2007 Activity	96,001	(104,882)	(436)		$454,149.90	($577,537.68)		($2,315.20)		
Balance Dec-07				78,286					$ 444,736.01	$ 4.72804
Jan-08	0	(31,018)	0	47,268	$0.00	$ (221,251.25)		$0.00	$ 223,484.76	$ 4.72804
Feb-08	0	(27,154)	0	20,114	$0.00	$ (128,385.06)		$0.00	$ 95,099.70	$ 4.72804
Mar-08	0	(20,114)	0	-	$0.00	$ (95,099.70)		$0.00	$ -	$ -
Apr-08	0	-	0	-	$0.00	$ -		$0.00	$ -	$ -
May-08	30,080	-	(80)	30,000	$279,464.26	$ -		($743.26)	$ 278,721.00	$ 9.29070
Jun-08	26096		(64)	56,032	$248,497.58	$ -		($610.62)	$ 526,607.96	$ 9.39834
Jul-08	8032	-	(16)	64,048	$77,276.88	$ -		($153.95)	$ 603,730.89	$ 9.42623
Aug-08	22121	-	(55)	86,114	$137,882.35	$ -		($342.92)	$ 741,270.32	$ 8.60801
Sep-08	9477	-	(26)	95,565	$47,560.29	$ -		($130.70)	$ 788,699.91	$ 8.25302
Oct-08	0	-	0	95,565	$1,935.00	$ -		($5.87)	$ 790,629.04	$ 8.27321
Nov-08	0		0	95,565	$0.00	$ -		$0.00	$ 790,629.04	$ 8.27321
Dec-08	0	(26,343)	0	69,222	$0.00	$ (217,941.16)		$0.00	$ 572,687.88	$ 8.27321
YTD 2008 Activity	95,806	(104,629)	(241)		$792,616.36	($662,677.17)		($1,987.32)		$127,951.87

Oregon JP Storage/Prepaid Gas

Account 164100 GD OR — **Contract 100408**

Storage Owned - Account for fuel as a withdrawal (808100). Price at WACOG. AVA gets a 1/3 charge from JP for fuel volumes burnt on both injections and withdrawals and assigns volumes to AN/OR for 100408 owned.

Dekatherms

GL Account	808200 GD OR	808100 GD OR	808100 GD OR		808200 GD OR	808100 GD OR	808100 GD OR	808100 GD OR	164100 GD OR	
	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Adjustments	Injection Fuel Value	Balance	Inventory WACOG
Balance Dec-06				0					$0.00	
Jan-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Feb-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Mar-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Apr-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
May-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Jun-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Jul-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	$ 4.22109
Aug-07	55,163	(13,201)	0	41,962	$230,845.65	($55,722.61)		$0.00	$175,123.04	$4.17337
Sep-07	38,931	(11,116)	(117)	69,660	$113,351.86	($39,624.76)		($436.52)	$248,413.62	$3.56609
Oct-07	0	(13,057)	(153)	56,450	$0.00	($46,573.50)		$545.58	$202,385.70	$3.58522
Nov-07	0	(11,477)	0	44,973	$0.00	($40,925.72)		($1,091.16)	$160,368.82	$3.56589
Dec-07	0	(10,794)	0	34,179	$0.00	($113,086.75)		$0.00	$47,282.07	$1.38337
YTD 2007 Activity	94,094	(59,645)	(270)		$344,197.51	($295,933.34)		($982.10)		
Balance Dec-07				34,179					$47,282.07	
Jan-08	-	(7,584)	-	26,595	$0.00	$ 47,552.83		$0.00	$94,834.90	$3.56589
Feb-08	-	(10,937)	-	15,658	$0.00	($39,000.14)		$0.00	$55,834.76	$3.56589
Mar-08	-	(11,282)	-	4,376	$0.00	($40,230.37)		$0.00	$15,604.39	$3.56590
Apr-08	11,000	(11,659)	-	3,717	$105,784.00	$ (92,043.96)		$0.00	$29,344.43	$7.89465
May-08	65,874	(10,793)	(23)	58,775	$ 613,862.85	$ (100,321.26)		$ (195.66)	$542,690.36	$9.23335
Jun-08	15,000	(9,577)	-	64,198	$ 139,032.00	$ (88,293.55)		$ (203.52)	$593,225.29	$9.24056
Jul-08	46,500	(8,774)	(13)	101,911	$ 415,978.50	$ (80,251.83)		$ (121.36)	$928,830.60	$9.11413
Aug-08	83,211	(11,741)	(148)	173,233	$ 490,705.30	$ (91,988.39)		$ (1,261.70)	$1,326,285.81	$7.65608
Sep-08	55,000	(5,345)	(193)	222,695	$ 270,447.00	$ (37,393.25)		$ (1,380.57)	$1,557,958.99	$6.99593
Oct-08	21,615	(12,091)	(262)	231,957	$ 72,466.15	$ (80,798.17)		$ (1,748.36)	$1,547,878.61	$6.67313
Nov-08	-	(61)	-	231,896	$ -	$ -		$ (407.06)	$1,547,471.55	$6.67313
Dec-08	-	(48,063)	-	183,833	$ -	$ (320,730.64)		$ -	$1,226,740.91	$6.67313
YTD 2008 Activity	298,200	(147,907)	(639)		$2,108,275.80	($923,498.73)		($5,318.23)		

Oregon Mist Storage/Prepaid Gas
Account 164110 GD OR

Storage Leased - Account for fuel as a reduction of injection (808200). Priced at daily injection price. AVA leases from Mist for OR and gets charged for fuel only on injections from NWP

Dekatherms										
GL Account	808200 GD OR	808100 GD OR	808200 GD OR		808200 GD OR	808100 GD OR	808100 GD OR	808200 GD OR	164110 GD OR	
	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Adjustments	Injection Fuel Value	Balance	Inventory WACOG
Balance Dec-06				0					$0.00	
Jan-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Feb-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Mar-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Apr-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
May-07	0	0	0	0	$0.00	$0.00		$0.00	$0.00	
Jun-07	105,312	0	(2,108)	103,204	$513,728.12	$0.00		($10,139.12)	$503,589.00	$ 4.87955
Jul-07	79,085	0	(1,580)	180,709	$374,084.07	$0.00		($7,700.15)	$869,972.92	$ 4.81422
Aug-07	64,882	0	(1,299)	244,292	$270,484.97	$0.00		($6,166.57)	$1,134,291.32	$ 4.64318
Sep-07	42,926	0	(855)	286,363	$126,543.83	$0.00		($3,854.41)	$1,256,980.74	$ 4.38947
Oct-07	13,910	0	(273)	300,000	$69,007.44	$0.00		$0.00	$1,325,988.18	$ 4.41996
Nov-07	0	0	0	300,000	$0.00	$0.00		($1,355.08)	$1,324,633.10	$ 4.41544
Dec-07	0	0	0	300,000	$0.00	$0.00		$0.00	$1,324,633.10	$ 4.41544
YTD 2007 Activity	306,115	0	(6,115)		$1,353,848.43	$0.00		($29,215.33)		
Balance Dec-07				300,000					$1,324,633.10	$ 4.41544
Jan-08	-	(155,000)	-	145,000	$0.00	($684,393.60)		$0.00	$640,239.50	$ 4.41544
Feb-08	-	(145,000)	-	-	$0.00	$ (640,239.50)		$0.00	$0.00	$ -
Mar-08	-	-	-	-	$ -	$ -		$ -	$0.00	$ -
Apr-08	-	-	-	-	$ -	$ -		$ -	$0.00	$ -
May-08	69,478	-	(1,384)	68,094	$ 643,471.03	$ -		$ (12,817.97)	$630,653.06	$ 9.26151
Jun-08	150,204		(3,004)	215,294	$ 1,396,460.21	$ -		$ (27,927.61)	$1,999,185.66	$ 9.28584
Jul-08	126,542	-	(2,542)	339,294	$ 1,132,016.18	$ -		$ (22,740.18)	$3,108,461.66	$ 9.16156
Aug-08	100,149	-	(1,995)	437,448	$ 640,230.85	$ -		$ (12,754.18)	$3,735,938.33	$ 8.54030
Sep-08	63,833	-	(1,281)	500,000	$ 321,787.40	$ -		$ (6,456.46)	$4,051,269.27	$ 8.10254
Oct-08	-	-	-	500,000	$ 2,962.49	$ -		$ (59.99)	$4,054,171.77	$ 8.10834
Nov-08	-	-	-	500,000	$ -	$ -		$ -	$4,054,171.77	$ 8.10834
Dec-08	-	(88,300)	-	411,700	$ -	$ (715,966.41)		$ -	$3,338,205.36	$ 8.10834
YTD 2008 Activity	510,206	(388,300)	(10,206)		$4,136,928.16	($2,040,599.51)		($82,756.39)		

Staff/702
Colville/13

Oregon Storage Inventory Account Totals Dekatherms 2009-2015	Injected Volumes	Withdrawal Volumes	Injection Fuel Volumes	Volume Balance	Injected Value	Withdrawal Value	Injection Fuel Value	Balance	Inventory WACOG	Injection Prices
Balance Dec-08				664,755				$ 5,137,633.64		
Jan-09	-	(228,997)	(145)	435,613	-	(1,671,952.58)	(662.65)	$ 3,465,018.41	$ 7.9544	$ 4.5700
Feb-09	-	(284,997)	(314)	150,302	-	(2,317,303.43)	(1,152.38)	$ 1,146,562.60	$ 7.6284	$ 3.6700
Mar-09	194,315	(150,304)	(2,877)	191,436	609,230.00	(1,146,563.10)	(9,020.18)	$ 600,209.32	$ 3.1357	$ 3.1353
Apr-09	100,181	(30,032)	(665)	260,920	273,790.39	(93,599.24)	(1,953.63)	$ 778,446.84	$ 2.9835	$ 2.7316
May-09	406,700	-	(3,667)	663,953	1,170,503.71	-	(10,610.52)	$ 1,938,340.03	$ 2.9194	$ 2.8779
Jun-09	250,182	(118,158)	(3,821)	792,156	678,874.10	(337,521.56)	(10,437.82)	$ 2,269,254.75	$ 2.8647	$ 2.7132
Jul-09	40,569	(273,952)	(5)	558,768	121,333.47	(786,373.09)	(13.85)	$ 1,604,201.28	$ 2.8710	$ 2.9908
Aug-09	106,066	(46,066)	(1,231)	617,537	293,082.39	(134,318.30)	(3,352.85)	$ 1,759,612.52	$ 2.8494	$ 2.7637
Sep-09	429,113	(186,204)	(2,638)	857,808	1,170,497.87	(503,348.04)	(7,328.82)	$ 2,419,433.53	$ 2.8205	$ 2.7274
Oct-09	21,084	-	(411)	878,481	88,578.89	-	(1,145.23)	$ 2,506,867.19	$ 2.8536	$ 4.2294
Nov-09	26,730	(47,272)	-	857,939	77,239.17	(136,699.19)	-	$ 2,447,407.17	$ 2.8527	$ 2.8896
Dec-09	78,966	(309,740)	(276)	626,889	438,633.68	(887,845.13)	(798.11)	$ 1,997,397.61	$ 3.1862	$ 5.5641
2009 Activity	1,653,906	(1,675,722)	(16,050)		4,921,764	(8,015,524)	(46,476)			
Balance Dec-09				626,889				$ 1,997,397.64		
Jan-10	-	(161,283)	(657)	464,949	-	(530,223.89)	(2,689.96)	$ 1,464,483.79	$ 3.1498	$ 4.0943
Feb-10	-	(316,019)	(145)	148,785	-	(1,041,852.32)	(593.64)	$ 422,037.83	$ 2.8366	$ 4.0941
Mar-10	328	(148,785)	(328)	-	1,214.88	(421,873.91)	(1,379.28)	$ (0.48)	$ -	$ -
Apr-10	153,523	-	(1,478)	152,045	570,329.39	-	(5,454.09)	$ 564,874.82	$ 3.7152	$ 3.7152
May-10	304,300	-	(3,872)	452,473	1,147,836.56	-	(14,606.00)	$ 1,698,105.38	$ 3.7529	$ 3.7721
Jun-10	200,850	-	(2,550)	650,773	823,299.11	-	(10,403.21)	$ 2,511,001.28	$ 3.8585	$ 4.0993
Jul-10	142,120	(107,818)	(1,885)	683,190	531,967.70	(414,586.11)	(7,069.76)	$ 2,621,313.11	$ 3.8369	$ 3.7430
Aug-10	140,096	(141,794)	(1,984)	679,508	455,552.08	(540,412.17)	(6,411.66)	$ 2,530,041.36	$ 3.7233	$ 3.2520
Sep-10	201,488	(41,630)	(1,708)	837,658	669,649.86	(153,062.06)	(5,694.05)	$ 3,040,935.11	$ 3.6303	$ 3.3234
Oct-10	20,768	-	(773)	857,653	69,962.09	-	(4,205.18)	$ 3,106,692.02	$ 3.6223	$ 3.2887
Nov-10	6,000	(56,187)	-	807,466	24,553.38	(202,518.97)		$ 2,928,726.43	$ 3.6271	$ 4.0922
Dec-10	97,515	(184,055)	(158)	720,768	387,244.45	(674,699.70)	(590.34)	$ 2,640,680.84	$ 3.6637	$ 3.9715
2010 Activity	1,266,988	(1,157,571)	(15,538)		4,681,610	(3,979,229)	(59,097)			
Balance Dec-10				720,768				$ 2,640,681.64		
Jan-11	-	(229,500)	(35)	491,233	-	(838,800.08)	-	$ 1,801,881.56	$ 3.6681	$ -
Feb-11	-	(364,523)	(153)	126,557	-	(1,339,458.27)	-	$ 462,423.29	$ 3.6539	$ -
Mar-11	-	(81,460)	(568)	44,529	-	(297,738.16)	-	$ 164,685.13	$ 3.6984	$ -
Apr-11	-	-	-	44,529	-	-	-	$ 164,685.13	$ 3.6984	$ -
May-11	209,513	-	-	254,042	827,751.25	-	-	$ 992,436.38	$ 3.9066	$ 3.9508
Jun-11	96,107	-	(371)	349,778	407,830.99	-	(1,502.58)	$ 1,398,764.79	$ 3.9990	$ 4.2443
Jul-11	158,856	(78,426)	(98)	430,110	647,010.95	(315,466.62)	(395.38)	$ 1,729,913.74	$ 4.0220	$ 4.0730
Aug-11	330,781	-	(368)	760,523	1,266,830.00	-	(1,437.00)	$ 2,995,306.74	$ 3.9385	$ 3.8297
Sep-11	159,665	-	(1,286)	918,902	602,657.00	-	(5,054.00)	$ 3,592,909.74	$ 3.9100	$ 3.7732
Oct-11	-	-	(629)	918,273	-	-	(2,463.00)	$ 3,590,446.74	$ 3.9100	$ 3.9[illegible]57
Nov-11	-	(14,400)	-	903,873	-	(56,393.00)	-	$ 3,534,053.74	$ 3.9099	#DIV/0!
Dec-11	-	(223,851)	(37)	679,985	-	(876,643.00)	(145.00)	$ 2,657,265.74	$ 3.9078	$ 3.9[illegible]89
2011 Activity	954,922	(992,160)	(3,545)		3,752,080	(3,724,499)	(10,997)			
Balance Dec-11				686,383				$ 2,677,417.88		
Jan-12	2,513	(205,811)	(570)	482,515	6,156.97	(802,456.01)	(2,187.67)	$ 1,878,931.17	$ 3.8940	$ 2.0429

Oregon Storage Inventory										
Account Totals										
Dekatherms										
2009-2015										
			Injection				Injection			
	Injected	Withdrawal	Fuel	Volume	Injected	Withdrawal	Fuel		Inventory	Injection
	Volumes	Volumes	Volumes	Balance	Value	Value	Value	Balance	WACOG	Prices
Feb-12	5,884	(188,293)	(671)	299,435	14,310.88	(719,526.68)	(2,616.08)	$ 1,171,099.29	$ 3.9110	$ 2.2434
Mar-12	193	(58,823)	(647)	240,158	548.93	(230,022.00)	(2,437.78)	$ 939,188.44	$ 3.9107	$ 4.1605
Apr-12	154,720	-	(496)	394,382	275,399.06	245.97	(1,619.66)	$ 1,213,213.81	$ 3.0762	$ 1.7752
May-12	162,186	(613)	(496)	555,459	322,968.86	(1,403.64)	(1,500.31)	$ 1,533,278.72	$ 2.7604	$ 1.9882
Jun-12	362,203	(72,009)	(265)	845,388	751,898.50	(184,486.80)	(668.42)	$ 2,100,022.00	$ 2.4841	$ 2.0756
Jul-12	6,083	(3,191)	(751)	847,529	15,544.40	(8,183.67)	(1,873.80)	$ 2,105,508.93	$ 2.4843	$ 2.5639
Aug-12	249,591	(217,841)	(464)	878,815	587,182.00	(542,050.66)	(1,125.69)	$ 2,149,514.58	$ 2.4459	$ 2.3524
Sep-12	139,130	(139,130)	(156)	878,659	342,379.80	(341,868.16)	(343.07)	$ 2,149,683.15	$ 2.4465	$ 2.4612
Oct-12	11,075	(12,191)	-	877,543	36,860.63	(38,592.93)		$ 2,147,950.85	$ 2.4477	$ 3.3283
Nov-12	4,505	(4,448)		877,600	15,618.89	(15,225.02)		$ 2,148,344.72	$ 2.4480	$ 3.4670
Dec-12	1,918	(20,919)		858,599	6,471.32	(53,823.13)		$ 2,100,992.91	$ 2.4470	$ 3.3740
2012 Activity	1,100,001	(923,269)	(4,516)		2,375,340	(2,937,393)	(14,372)			
Balance Dec-12				858,599				$ 2,100,992.88		
Jan-13	8,703	(783,846)	(43)	83,413	28,064.87	(1,931,089.76)	(105.89)	$ 197,862.10	$ 2.3721	$ 3.2285
Feb-13	4,645	(3,227)	(2,625)	82,206	15,546.23	(10,759.69)	(6,464.48)	$ 196,184.16	$ 2.3865	$ 4.4959
Mar-13	-	(1,446)	-	80,760	-	(4,876.80)		$ 191,307.36	$ 2.3688	#DIV/0!
Apr-13	-	(77,565)	-	3,195	-	(183,898.93)	-	$ 7,408.43	$ 2.3188	#DIV/0!
May-13	225,222	(281)	(118)	228,018	820,616.74	(1,058.84)	(422.50)	$ 826,543.83	$ 3.6249	$ 3.6436
Jun-13	199,268	(90,548)	(599)	336,139	665,148.59	(319,063.29)	(2,091.39)	$ 1,170,537.74	$ 3.4823	$ 3.3375
Jul-13	138,233	(499)	(213)	473,660	401,657.49	(1,238.68)	(736.95)	$ 1,570,219.60	$ 3.3151	$ 2.9048
Aug-13	272,105	(14)	(378)	745,373	707,698.53	(33.61)	(1,216.71)	$ 2,276,667.81	$ 3.0544	$ 2.6000
Sep-13	142,235	(5,207)	(845)	881,556	281,606.87	(15,754.47)	(2,516.66)	$ 2,540,003.55	$ 2.8813	$ 1.9739
Oct-13	74,693	(507)	(543)	955,199	217,587.03	(1,438.59)	(1,579.93)	$ 2,754,572.06	$ 2.8838	$ 2.9131
Nov-13	46,282	(276,395)	(72)	725,014	184,447.99	(812,432.41)	(209.49)	$ 2,126,378.15	$ 2.9329	$ 3.9870
Dec-13	55,764	(320,008)	(575)	460,195	259,319.61	(970,335.10)	(1,693.70)	$ 1,413,668.96	$ 3.0719	$ 4.6681
2013 Activity	1,167,150	(1,559,543)	(6,011)		3,581,694	(4,251,980)	(17,038)			
Balance Dec-13				460,195				$ 1,413,668.88		
Jan-14	2,719	(154,386)	(805)	307,723	11,837.19	(475,234.99)	(2,510.19)	$ 947,760.89	$ 3.0799	$ 4.8730
Feb-14	855	(202,262)	(717)	105,599	5,351.86	(625,250.40)	(2,235.79)	$ 325,626.56	$ 3.0836	$ 22.5802
Mar-14	-	(104,512)	(850)	237	-	(321,941.29)	(2,650.57)	$ 1,034.70	$ 4.3658	$ 3.1183
Apr-14	-	(54)	(487)	(304)	-	(336.79)	(1,518.63)	$ (820.72)	$ 2.6997	$ 3.1183
May-14	261,314	(1)	(48)	260,961	1,125,674.35	(6.32)	(168.28)	$ 1,124,679.03	$ 4.3098	$ 4.3079
Jun-14	76,993	-	(311)	337,643	341,072.29	-	(1,262.12)	$ 1,464,489.20	$ 4.3374	$ 4.4314
Jul-14	168,598	-	(130)	506,111	669,997.47	-	(682.36)	$ 2,133,804.31	$ 4.2161	$ 3.9730
Aug-14	251,842	-	(249)	757,704	949,658.07	-	(984.36)	$ 3,082,478.02	$ 4.0682	$ 3.7707
Sep-14	146,510	(10,044)	(805)	893,365	551,411.82	(40,363.02)	(3,224.82)	$ 3,590,302.00	$ 4.0189	$ 3.7623
Oct-14	12,958	(184)	(356)	905,783	42,591.36	(701.19)	(1,430.63)	$ 3,630,761.54	$ 4.0084	$ 3.2662
Nov-14	63,934	(130,758)	(49)	838,910	227,824.23	(519,926.53)	(195.34)	$ 3,338,463.90	$ 3.9795	$ 3.5631
Dec-14	78,230	(124,120)	(392)	792,628	228,979.01	(485,781.43)	(1,547.72)	$ 3,080,113.76	$ 3.8860	$ 2.9219
2014 Activity	1,063,953	(726,321)	(5,199)		4,154,398	(2,469,542)	(18,411)			

Staff/702
Colville/14

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	05/15/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 125	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

Please provide, in the spreadsheet requested above, the historical cushion gas inventory balances for each storage facility (in both volume and in dollars), by month from the first date each storage facility was placed in operation through 2014, and to the extent as available monthly through 2015. For the dollar values provided, please provide an explanation as to how the dollar value was derived. Please identify whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2005 through 2014, and to the extent as available monthly through 2015. Provide results separately for total company and for Oregon. This request relates to Avista/501, Smith/4 at line 246 through 252, and Avista/502, Smith/5 at lines 246 through 252.

RESPONSE:

Working gas capacity, as requested in Staff_DR_124 changes every month based on daily/monthly injections and withdrawals. Cushion gas, however, remains constant unless there is a major expansion completed. Oregon customers have participated in two expansions of the facility. Balances are summarized in the table below:

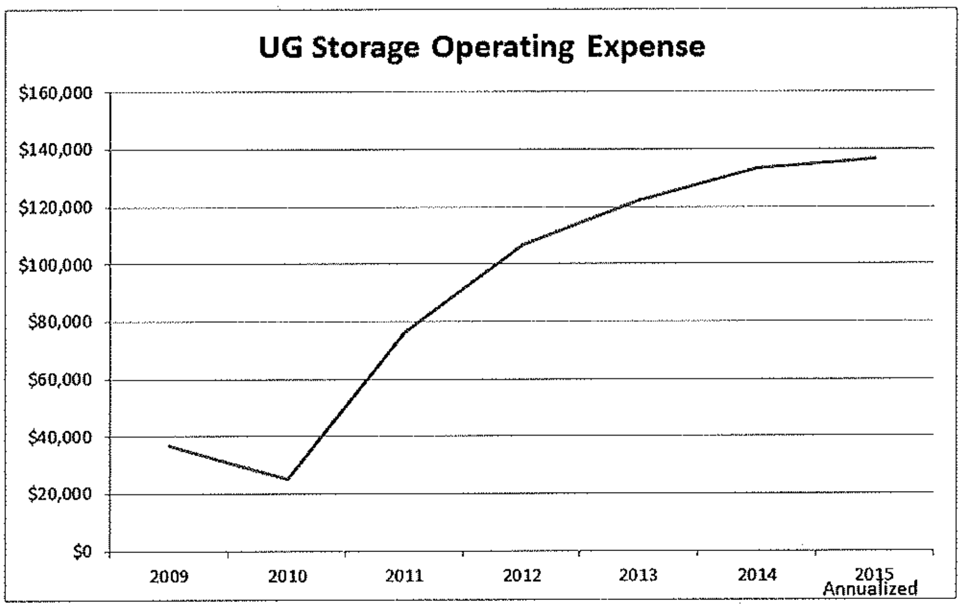
	Ending Balance 10/31/2008	Ending Balance 05/31/2011
Cushion Gas Dth	174,964	495,223
Cushion Gas $	$976,027	$1,711,623

The cushion gas value is based on the cost of the cushion gas as it was being injected into the facility in accordance with GAAP. No labor dollars are included. The above balances include both recoverable FERC account 117.1 and non-recoverable 352.3.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/07/2015
CASE NO:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 208	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:
Related to Avista's response to Staff DR 123, please provide a description of the cause for 2010 underground storage operating expenses deviating from the 2009 and 2011 expenses. Refer to the figure below.



RESPONSE:

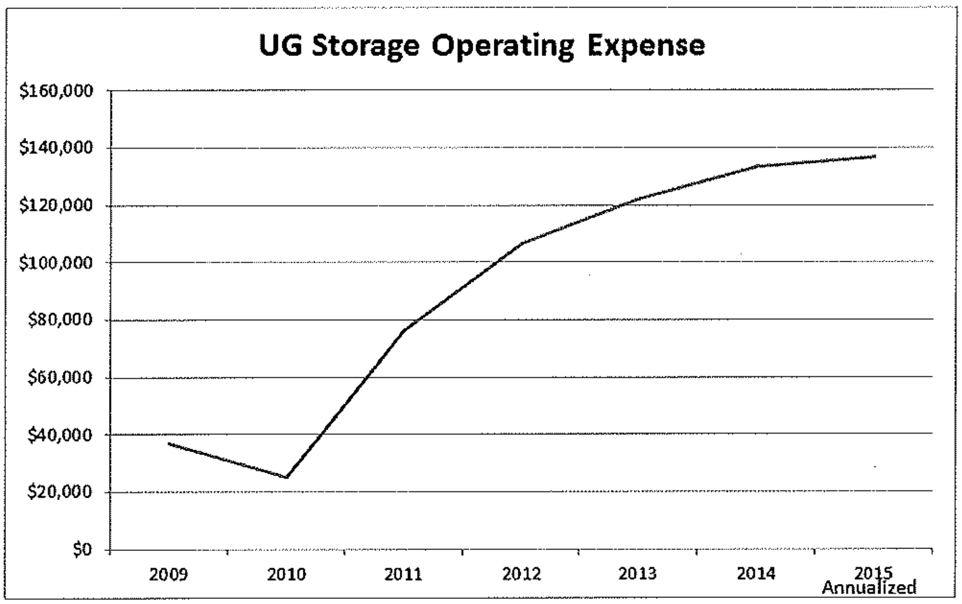
Beginning in May 2011, Oregon's share of Jackson Prairie operating and maintenance expenses increased from 3.08% to 9.65% corresponding with the increase in capacity for Oregon customers. This increase in allocation percentage is the primary reason for the increase in expenses between 2010 and 2011. Please see the Company's response to Staff_DR_209 for a table summarizing the allocation change. In addition, there is a timing lag associated with invoice processing and expense recognition because Avista is not the operating partner for Jackson Prairie. For example, $46,000 of costs incurred in 2010 were expensed in 2011.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/07/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Colville	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 209	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

Related to Avista's response to Staff DR 123, please provide a description of the cause for the more rapid increase in expenses before 2012 than after 2012. Refer to the figure below.



RESPONSE:

As noted in the Company's response to Staff_DR_208, beginning in May 2011 Oregon's share of Jackson Prairie operating and maintenance expenses increased from 3.08% to 9.65% corresponding with the increase in capacity for Oregon customers. This is the primary contributor for more rapid increase in expenses pre-2012 than post-2012.

The table below summarizes this change:

Calculations for JP Costs Allocation		
Jackson Praire (JP) Allocation		
	Dth	**Allocation**
January 2009 - April 2011		
Washington & Idaho (AN)	5,234.666	61.38%
Oregon	262.446	**3.08%**
Avista Energy Capacity release to Shell	3,030.901	35.54%
Total Capacity	8,528.013	100.00%
May 2011 - Current		
Washington & Idaho (AN)	7,704.676	**90.35%**
Oregon	823.337	9.65%
Total Capacity	8,528.013	100.00%

CASE: UG 288
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

Exhibits in Support
Of Opening Testimony

October 16, 2015

Exhibit Staff/703

Other Gas Supply Expense

Calendar Years 2005-2014

		2005	2006	2007	2008	2009	2010	2011 (a)	2012	2013	2014 (b)
Acct	**Description**	**12/31/2005**	**12/31/2006**	**12/31/2007**	**12/31/2008**	**12/31/2009**	**12/31/2010**	**12/31/2011**	**12/31/2012**	**12/31/2013**	**12/31/2014***
813010	GTI	$ -	$ -	$ -	$ -	$ -	$ 11,959	$ 47,508	$ 43,989	$ 47,751	$ 40,632
	GTI	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 11,959**	**$ 47,508**	**$ 43,989**	**$ 47,751**	**$ 40,632**
813000	OTHER EXPENSE - Labor	$ 387,728	$ 186,588	$ 191,991	$ 239,623	$ 252,767	$ 254,295	$ 268,009	$ 237,604	$ 225,823	$ 229,743
813000	OTHER EXPENSE - Non Labor	not avail	$ 231,149	$ 329,765	$ 304,732	$ 288,507	$ 243,023	$ 291,882	$ 266,410	$ 269,970	$ 235,939
	OTHER EXPENSE	**$ 387,728**	**$ 417,737**	**$ 521,756**	**$ 544,355**	**$ 541,274**	**$ 497,318**	**$ 559,891**	**$ 504,014**	**$ 495,793**	**$ 465,681**
	TOTAL	$ 387,728	$ 417,737	$ 521,756	$ 544,355	$ 541,274	$ 509,277	$ 607,399	$ 548,003	$ 543,544	$ 506,313

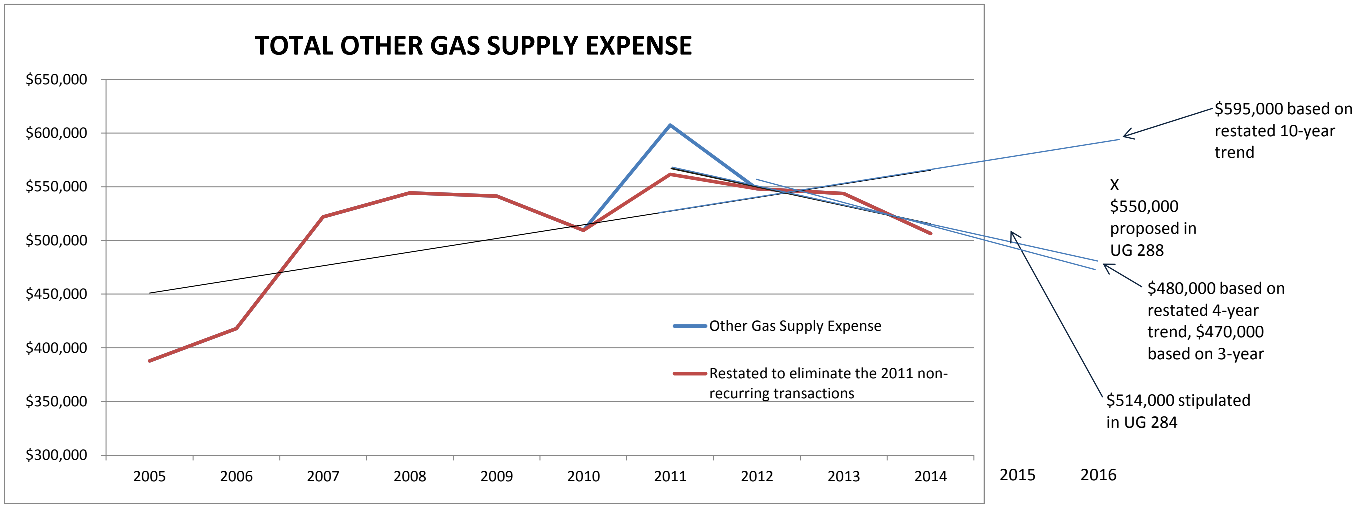
* Total amount ties to 2014 Restated Historical AMA Base Test Year and excludes all PGA Accounts.

(a) 2011 included two non-recurring transactions.

1	Encana Gas Reserve Write Off	$ 26,000	The Company elected not to move forward with the Encana Gas Reserve Deals and wrote off expenses accrued for this purpose.
2	Labor Back-fill	$ 20,000	
	Total	$ 46,000	

(b) Reduction in non-labor expense from 2013 to 2014 is due to the change in Labor Loading Rates from 63% (Dec. 2013) to 39% (Dec 2014). This is due to various actuarial assumptions for Pension and Medical regarding the discount rate and expected return on assets. Please see Staff_DR_059C Confidential Attachment A for year over year comparison.

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Restated to eliminate the 2011 non-recurring transactions	$ 387,728	$ 417,737	$ 521,756	$ 544,355	$ 541,274	$ 509,277	$ 561,399	$ 548,003	$ 543,544	$ 506,313



TOTAL OTHER GAS SUPPLY EXPENSE
$650,000
$600,000
$550,000
$500,000
$450,000
$400,000
$350,000
$300,000
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
Other Gas Supply Expense
Restated to eliminate the 2011 non-recurring transactions
$595,000 based on restated 10-year trend
X
$550,000 proposed in UG 288
$480,000 based on restated 4-year trend, $470,000 based on 3-year
$514,000 stipulated in UG 284

CASE: UG 288
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Medical Benefits, Wages & Salaries, Property Taxes, Pension Adjustment

Opening Testimony

October 16, 2015

CERTAIN INFORMATION CONTAINED IN

STAFF EXHIBIT 800

PAGES 7, 9-12, and 14

ARE CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN DOCKET NO. UG 288.

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

A. My name is Brian Bahr. My business address is 201 High St. SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to specific issues in Avista Corporation's (Avista or Company) request for general rate revision. Staff responds to the issues of medical benefits, wages and salaries, property taxes, and pensions and postretirement benefits.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/802, consisting of 35 pages, and Confidential Exhibit Staff/803, consisting of 14 pages. The exhibits contain analysis, responses to Staff data requests, and external references that support Staff's recommendations.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Summary of Recommendations

Q. Please provide a summary of Staff's recommendations.

A. The following table illustrates the adjustments proposed by Staff.

Table 1. Adjustments proposed by Staff

	Adjustment (000)	Expense or Rate Base
FAS 87 Pension Cost	$348	Expense
Postretirement Benefits	$24	Expense
Prepaid Pension Asset (net of deferred taxes)	$5,655	Rate Base
Debt Interest on Prepaid Pension Asset	$63	Expense
Medical Benefits	$175	Expense
Property Taxes	$67	Expense
Wages & Salaries	$62	Expense
Wages & Salaries	$5	Rate Base
Incentives	$288	Expense
Incentives	$278	Rate Base
Payroll Taxes	$17	Expense
Depreciation (for Cap adj)	$0.2	Expense

Issue 1, Pensions and Postretirement Benefits

Q. How are pension costs typically treated by the Commission?

A. Though most expenses approved for inclusion in rates are based on cash costs during a company's test year, cash payments from a company to its pension fund can be volatile from year to year, depending on market and interest rates, as well as changing pension regulations. Because of the volatility of these cash payments, the Commission currently uses accrual pension costs as a proxy for cash payments. These accrual pension costs are calculated in accordance with applicable standardized accounting guidance and called a Company's Financial Accounting Standard (FAS) 87 expense.

The Commission recently conducted a general investigation into the recovery of pension costs in Docket No. UM 1633. In that docket, the Commission investigated whether FAS 87 expense should be continued for use in rate recovery of pension costs, whether a company's prepaid pension asset should be included in rate base, and whether there are more effective methods of pension cost recovery than those currently in practice in Oregon. Commission Order No. 15-226 reaffirmed the current pension cost recovery method for use in setting rates (ie. Forecasted FAS 87 expense used for ratemaking, net prepaid pension asset not allowed in rate base).

Q. Please describe the Company's request regarding pension costs.

A. The Company's proposed revenue requirement includes the test year pension expense of $21 million on a total company basis, which is approximately

$998,000 on an Oregon-allocated basis.[1] Also included is Postretirement Medical Benefit (FAS 106) expense of $8.8 million (total company), which is $418,000 on an Oregon-allocated basis.[2]

The Company also included in rate base its estimated prepaid pension asset, net of its related accumulated deferred taxes. The prepaid pension asset is defined as the difference between the Company's total cash payments into its pension fund and the cumulative accrual expense the Company has incurred, as calculated under FAS 87 and other relevant Generally Accepted Accounting Principles (GAAP). The Company included in the test year rate base the balance of the prepaid pension asset, net of the $2.3 million of accumulated deferred taxes associated with it, of approximately $5.7 million (Oregon allocated).[3] A similar asset/liability account exists for the Company's postretirement benefit account. In Avista's case, the Company has an accrued liability of $1.3 million that reduces its working capital.[4]

Q. How did Staff analyze the Company's requested pension costs?

A. Staff reviewed the Company's responses to 15 Staff data requests related to pension costs as well as the testimony and supporting work papers included in the Company's filing. Staff also had various phone calls with the Company to discuss aspects of its pension costs. In analyzing the Company's requested pension costs, Staff distinguished between the three parts of the proposed

[1] Confidential Exhibit Staff/803, Bahr/1. Company's confidential response to Staff Data Request No. 60.
[2] *Ibid.*
[3] Exhibit Staff/802, Bahr/1. Company Workpaper Smith 2.03.
[4] Exhibit Staff/802, Bahr/2-4. Company Workpaper Smith 2.08.

cost, the requested FAS 87 expense amount, the inclusion in rate base of both the prepaid pension asset and the related accumulated deferred taxes, and the postretirement medical benefits.

FAS 87 Expense

As described above, the Commission has historically relied on FAS 87 expense as a reasonable representation of cash costs in any given year. The FAS 87 expense amount is calculated and determined by third-party actuaries. Though most of the calculation's inputs are based on actual costs and amounts, two of the inputs require a degree of subjective judgment; these are the expected long term market rate of return on pension assets (Expected Return on Assets or EROA) and the expected discount rate. Typically in reviewing pension costs as part of a general rate case, Staff analyzes these two inputs, reviews them for reasonableness, verifies the calculation, and potentially recommends an adjustment to the proposed cost based on recommended changes to the EROA or discount rate.

Staff carefully reviewed the recent reports prepared by the third party actuary that detail the calculations and inputs of the pension cost calculations. To compare the Company's EROA and discount rate used in the FAS 87 expense calculation to those of other utility companies regulated in Oregon, Staff constructed the table on the following page using 2014 SEC 10k filings found online. As seen in the table on the following page, the Company's EROA was less than that of all five other companies' in both 2013 and 2014.

Table 2. Expected Rate of Return on Assets used in FAS 87 Calculations

Company	2013	2014
Avista[5]	6.6%	6.6%
Cascade[6]	7%	7%
Idaho Power[7]	7.75%	7.75%
NW Natural[8]	7.5%	7.5%
PacifiCorp[9]	7.5%	7.5%
PGE[10]	8.25%	7.5%
AVERAGE	**7.43%**	**7.31%**

The Company essentially relies on its third party actuary to determine its pension expense. However, the Company does have discretion in managing its pension asset investment mix.[11] According to the Company's response to a Staff Data Request:[12]

> *Avista moved its Retirement Plan assets from a 31% fixed income allocation to 58% fixed income allocation during 2014. While fixed income investments typically have lower expected returns than equity investments, their changes in*

[5] Avista's 2014 10k can be found online at: http://www.annualreports.com/Click/6241?_SID_=20150706190117-2fe6be35324430e88f3e9d1d6c83301a. Page 89 is included as Exhibit Staff/802, Bahr/5.
[6] Cascade's 2014 10k can be found online at: http://www.mdu.com/docs/default-source/Proxy-Materials/2014-annual-report-10-k-and-proxy.pdf. Page 89 is included as Exhibit Staff/802, Bahr/6.
[7] Idaho Power's 2014 10k can be found online at: http://www.idacorpinc.com/pdfs/annualreps/ar2014.pdf. Page 110 is included as Exhibit Staff/802, Bahr/7.
[8] NW Natural's 2014 10k can be found online at: https://www.nwnatural.com/Content/AnnualReport/2014/files/10K_2014.pdf. Page 72 is included as Exhibit Staff/802, Bahr/8.
[9] PacifiCorp's 2014 10k can be found online at: https://www.last10k.com/Search/LoadPDF?u=http://www.last10k.com/sec-filings/75594/000007559415000003/pacificorp123114form10-k.htm.pdf. Page 79 is included as Exhibit Staff/802, Bahr/9.
[10] PGE's 2014 10k can be found online at: http://files.shareholder.com/downloads/POR/401492826x0xS784977-15-5/784977/filing.pdf. Page 102 of the report is included as Exhibit Staff/802, Bahr/10.
[11] Exhibit Staff/802, Bahr/11. Company's response to Staff Data Request No. 147.
[12] Exhibit Staff/802, Bahr/12-13. Company's supplemental response to Staff Data Request No. 204.

value tend to correlate well to the nature of obligations in the pension plan, and the result is less volatility in funded levels of the Retirement Plan and less volatility in annual pension expense.

Due to its change in asset mix, the Company's forecasted EROA used in its filed case decreased from the 6.6 percent used in 2014 to [redacted] percent.[13] The Company received an updated actuarial report subsequent to its initial filing that reduces the EROA even further from [redacted] percent to [redacted] percent.[14] Again, no other regulated utility in Oregon has an EROA below 7 percent at this time, and the average EROA in 2014 was 7.31 percent.

The Company provided additional information to support its asset allocation and low forecasted EROA. Excerpts of the Company's response to a Staff Data Request are included as follows:[15]

At higher levels of funding, however, the objective shifts toward maintaining, not increasing the plans' funded status. The implementation of a "derisking strategy" whereby a portion of the overall portfolio is transferred from equity investments to fixed income investments, aids in the reduction of risk and volatility and strengthens the correlation between the Retirement Plan Obligations and the Retirement Plan assets. … "Other companies may have significantly

[13] Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.
[14] Exhibit Staff/802, Bahr/14-15. Company's response to Staff Data Request No. 143.
[15] Exhibit Staff/802, Bahr/16-17. Company's response to Staff Data Request No. 303.

different funded status for their pension obligations and significantly different investment philosophies and, hence, their expected return on assets would be derived from their situations."

To evaluate whether higher funded statuses actually correlate with lower EROAs for the Oregon-regulated energy utilities, as the Company argues in support of its forecasted EROA, Staff put together the following table, comparing the funded status and EROA for the six regulated energy utilities operating in Oregon:[16]

Table 3. Funded Status and EROA of Oregon-Regulated Utilities

2013				2014		
Company	**% Funded**	**EROA**		**Company**	**% Funded**	**EROA**
Avista	91.37%	6.60%		Avista	84.97%	6.60%
Cascade	83.13%	7.00%		Cascade	74.55%	7.00%
Idaho Power	78.42%	7.75%		Idaho Power	66.25%	7.75%
NW Natural	73.70%	7.50%		NW Natural	61.88%	7.50%
PacifiCorp	95.20%	7.50%		PacifiCorp	83.16%	7.50%
PGE	84.54%	8.25%		PGE	76.06%	7.50%

A correlation coefficient of 1 would indicate that the data is perfectly positively correlated; or in other words, that a higher EROA would correlate perfectly with a higher funded percentage. A correlation coefficient of -1 would indicate a perfect negative correlation; or in other words, that a high funded percentage would perfectly correlate with a low EROA. A correlation coefficient of 0 would indicate no correlation between the two data sets whatsoever. The correlation coefficient of the two sets of data (% Funded and

[16] The information used for this table was retrieved from the same sources as those noted in Table 2 on page 6 of Staff's testimony. Calculations of the funded percentage are shown in Exhibit Staff/802, Bahr/18.

EROA) is -0.29. This indicates a negative correlation between the two data sets, although a relatively weak one. In other words, the data above mildly supports Avista's claim that higher funded percentages should correlate with lower expected rates of return on assets.

There are two additional important points to note. The first is that despite the derisking strategy implemented by Avista in 2014, its funded percentage still fell from over 91 percent to just under 85 percent over the course of the 2014 calendar year. Even though the Company's funded percentage decreased significantly during 2014, the Company lowered its EROA even further in 2015 from 6.6 percent to [redacted] percent, which was then revised to [redacted] percent. The second point of note is that PacifiCorp's 2013 funded percentage is the highest of all six utilities in either 2013 or 2014, and has the most similar funded percentage as Avista in both 2013 and 2014, and yet PacifiCorp maintains an EROA of 7.5 percent, well above Avista's.

<u>Prepaid Pension Asset</u>

With regard to the Company's request to include in rate base the prepaid pension asset, net of accumulated deferred taxes, Staff notes this request is similar to requests made in recent general rate cases of other utility companies such as Cascade, (Docket No. UG 287), NW Natural (Docket No. UG 221), PacifiCorp (Docket No. UE 263), Avista (Docket Nos. UG 246 and UG 284), and PGE (Docket Nos. UE 283 and UE 262). As these rate cases have been concurrent with Docket UM 1633, the Commission's general investigation into pension cost recovery, Staff recommended in each case that no change to cost recovery methods was warranted until the conclusion of the general investigation.

Postretirement Medical Benefits

Medical benefits paid to retirees are generally treated akin to a Company's FAS 87 pension expense. Similar to how the accounting treatment for pension costs is prescribed by FAS 87, FAS 106 addresses the treatment of retirement benefit costs and defines the calculation of the cost using variable inputs such as EROA, discount rate, etc. In calculating its FAS 106 expense in its original filing, the Company used an EROA of [redacted] percent.[17] The Company's revised forecast, provided to Staff in response to Staff Data Request No. 149, uses an EROA of [redacted] percent.[18] From 2012 to 2014, the Company earned returns on its postretirement medical benefits asset of [redacted] percent, [redacted] percent, and [redacted] percent.[19] While past returns are not necessarily indicative of future results, Staff questions the Company's low forecasted return on its assets, especially considering that it's significantly lower than the Company's requested return in this rate case.

Q. What adjustments does Staff propose to the company's proposed pension and postretirement medical benefit costs?

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[17] Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.

[18] Confidential Exhibit Staff/803, Bahr/6-7. Company's supplemental confidential response to Staff Data Request No. 149.

[19] Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.

A. Staff proposes adjustments to the Company's proposed FAS 87 expense, the prepaid pension asset included by the Company in rate base, and the postretirement medical benefits expense.

FAS 87 Expense

Although Staff is well aware of a general market trend of declining EROAs,[20] Staff does not agree with an investment strategy that reduces the Company's expected return on assets to a rate approximately [redacted] full basis points below the average for the six regulated Oregon utilities, [redacted] basis points below the next closest utility EROA, and likely significantly below the Company's authorized return. Staff finds the EROA revision even more absurd considering the Company has earned returns on its pension asset of [redacted] percent, [redacted] percent, and [redacted] percent from 2012 through 2014.[21]

By allowing a FAS 87 expense calculated at that EROA, the Commission would essentially be allowing the Company to charge customers an amount at a return higher than 7 percent and invest the money in a fund expected to return only [redacted] percent. Though there are certain considerations, such as potential volatility of investments and the expected time horizon (short term versus long term), this arbitrage would not be fair to customers. By using the next lowest EROA for an Oregon-regulated utility, 7 percent rather than [redacted] percent (as filed) or [redacted] percent (updated), Staff's adjustment reduces the

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[20] The trend of declining EROAs for pension funds has been widely reported through various news outlets. Eg. http://www.wsj.com/articles/SB10001424052702304026304579453740108053288 and http://www.wsj.com/articles/taxpayers-more-pension-burdens-headed-your-way-1441388090.

[21] Confidential Exhibit Staff/803, Bahr/2-5. Company's confidential response to Staff Data Request No. 59.

Company's proposed Oregon-allocated FAS 87 expense of [redacted] and to [redacted], a difference of $348,000. Details and calculations of Staff's adjustment can be found at Confidential Exhibit Staff/803, Bahr/8-9.

Prepaid Pension Asset

With regard to the prepaid pension asset, per Order No. 15-226 in Docket No. UM 1633, Staff recommends removing it from rate base, net of the associated deferred taxes, as well as the associated debt interest and related flow-through cost items. The net rate base adjustment related to the prepaid pension asset and its associated deferred taxes is $5.655 million. The flow-through adjustment related to debt interest is $63,000. Details and calculations of Staff's adjustment can be found at Confidential Exhibit Staff/803, Bahr/8-9.

Postretirement Medical Benefits

Similar to FAS 87 expense, postretirement medical benefits should be adjusted to reflect a higher EROA than that proposed by the Company. Adjusting the EROA to 7 percent from its filed EROA of [redacted] percent and revised update of [redacted] percent results in an adjustment to the Company's expenses of $450,000 on a system basis, and $24,000 on an Oregon-allocated basis. Details and calculations of Staff's adjustment can be found at Confidential Exhibit Staff/803, Bahr/8-9.

Q. Are there any other issues relating to pensions or postretirement benefits that Staff needs to address?

A. Yes. Order No. 15-226 in Commission Docket No. UM 1633, the general investigation into the treatment of pension costs, affirms the Commission's current policy of not including a utility's prepaid pension asset in rate base. The order, however, is silent as to the treatment of the prepaid asset or accrued liability associated with postretirement medical benefits costs. Because FAS 106 costs are generally treated similarly to FAS 87 costs, Staff recommends the Commission allow the Company to remove from its rate base the accrued liability associated with its postretirement medical benefits plan, in conjunction with the prepaid asset associated with the pension plan. For Avista, this results in an increase to rate base of $1.3 million. However, Staff Gardner has already proposed an adjustment to the Company's working capital that includes this amount; therefore, Staff need not make an additional adjustment here. Further details of the adjustment to working capital can be found in Staff Gardner's testimony.

Issue 2, Medical Benefits

Q. Please describe the Company's request regarding medical, dental, vision, and other benefits.

A. The Company has requested approximately $[redacted] million in test year expenses relating to benefits on a system level, which is $[redacted] million on an Oregon-allocated basis.[22] This cost includes such forms of compensation as long-term disability benefits, employee wellness program, and the pension plan. The expense includes costs for both bargaining (union) and non-bargaining (non-union) employees. Benefit plan premiums are typically shared between the Company and the employees. The Company generally shares costs with employees at a ratio of 90/10 (i.e. employees pay 10 percent of premium costs and the Company pays 90 percent).

Q. Please describe the analysis performed by Staff.

A. As noted above, the Company's medical benefits include various categories of expenses. For Deferred Comp, Employee Assistance, HRA Benefit, Life/LT Disability/Other, Service Awards, and Tuition Aid, the Company escalated the 2014 base year costs by less than 1%. The test year total for these amounts is less than it was in 2011, 2012, and 2013. Staff does not propose an adjustment related to these expenses.

For Health Insurance, Staff recommends employer/employee sharing of premium costs at 82/18, rather than that proposed by the Company of 90/10. A survey in the 2014 Kaiser Family Foundation publication indicates that the

[22] Confidential Exhibit Staff/803, Bahr/10-11. Company's confidential response to Staff Data Request No. 63.

average sharing ratio in the industry is 82/18 for single employees and 71/29 for families. Staff typically relies on Kaiser Family Foundation research for industry health benefit trends and to date has yet to find a compelling reason to rely more heavily on other evidence. Regarding premium sharing, the survey states, "*Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2013.*"[23]

Because the cost of health insurance increases by 15.54% from actual 2014 to forecasted 2016, Staff used trend analysis of 2011 through 2014 to forecast the 2016 costs before making the premium sharing adjustment. Staff's adjustment comprises the difference between the Company's proposed test year amount versus Staff's trend forecast, and the difference between sharing the cost at a ratio of 82/18 versus 90/10.

Staff typically proposes no adjustment to sharing between the Company and its bargaining employees unless the sharing percentage is deemed unreasonable upon review. These rates are negotiated between the Company and the union, include a wide range of total compensation elements, and are difficult to adjust without upsetting the carefully negotiated compensation balance.

Q. Does Staff propose any adjustments relating to medical benefits?

[23] The 2014 Kaiser Family Foundation Report executive summary can be found online at http://files.kff.org/attachment/ehbs-2014-abstract-summary-of-findings. The premium sharing information used by Staff is found on page one, included as Exhibit Staff/802, Bahr/19.

A. Yes. Staff's adjustment consists of two reductions to the Company's proposal. The first adjustment is related to historical trends, and the second adjustment is related to employer/employee sharing. Applying both of these adjustments results in an adjustment to expense of $175,000. Details and calculations of Staff's adjustment can be found at Confidential Exhibit Staff/803, Bahr/12-14.

Issue 3, Property Taxes

Q. Please describe the Company's request associated with property taxes.

A. The Company proposed approximately $2.5 million of property taxes for inclusion in its test year expense.[24] This was based on an estimated property tax rate of 0.01341 applied to a tax base of approximately $184.7 million. The Company forecasted the property tax rate by escalating the base year rate by 3 percent, as shown in the calculation below.

Table 4. Avista's Forecasted Test Year Property Taxes

0.01303	2014 tax rate (per UG 288 Smith WP 2.04)[25]
0.03	escalation factor used by Company
0.01341	2015 forecasted tax rate (per UG 288 Smith WP 2.04)
$184,700,000	2014 property value included in case (per UG 288 Smith WP 2.04)
$2,477,471	amount included by Company in test year

Q. How did Staff analyze the Company's requested property tax cost?

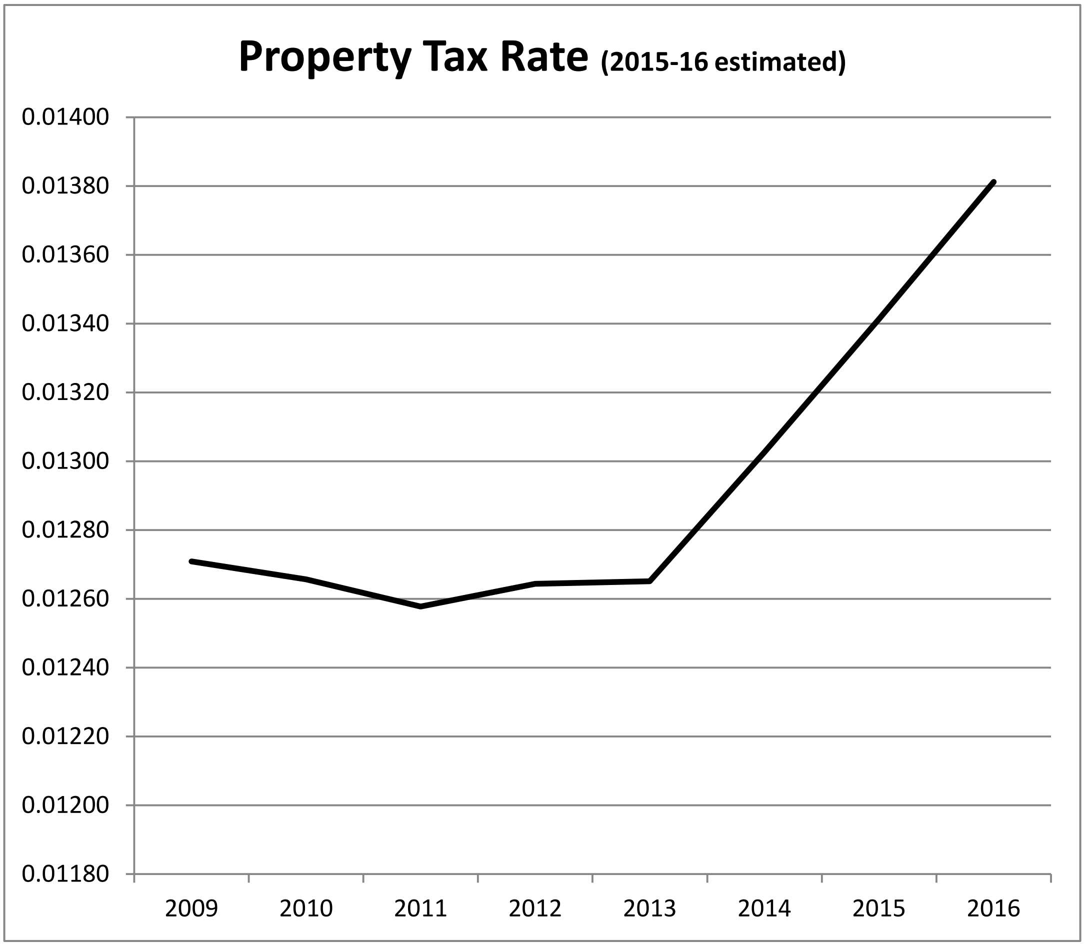
A. The Company calculated its test year property tax expense by forecasting the expected property tax rate. The Company's forecast relied on an escalation factor of approximately 3 percent annually from the base year to the test year. Staff analyzed the historical property tax rate from 2007 through the test year, resulting in the following data shown in table and graph form:

[24] Exhibit Staff/802, Bahr/20-22. Company Workpaper 2.04.
[25] *Ibid.*

Table 5. Property Tax Rates 2007 through forecasted 2016

Year	Property Tax Rate	Source
2009	0.01271	Tax Rate (per UG 201 Andrews WP $F4_5$) [26]
2010	0.01266	Tax Rate (per UG 246 Andrews WP G-FPT-4)[27]
2011	0.01258	Tax Rate (per UG 246 Andrews WP G-FPT-4)
2012	0.01264	Tax Rate (per UG 246 Andrews WP G-FPT-4)
2013	0.01265	Tax Rate (per UG 288 Smith WP 2.04)
2014	0.01303	Tax Rate (per UG 288 Smith WP 2.04)
2015	*0.01341*	*forecasted Tax Rate (per UG 288 Smith WP 2.04)*
2016	*0.01381*	*forecasted Tax Rate (per UG 288 Smith WP 2.04)*

Figure 1. Property Tax Rate (actual 2009-2014, forecasted 2015-2016)



[26] Exhibit Staff/802, Bahr/23.
[27] Exhibit Staff/802, Bahr/24.

Q. Does Staff propose an adjustment related to property taxes?

A. Yes. Based on the historical information, the Company's forecast for 2015 and 2016 appears excessively aggressive. Rather than using the Company's 3 percent escalation factor, Staff forecasted the test year property tax rate by escalating the base year rate by the All-Urban CPI typically used by Staff, which is 0.2 percent.[28] This results in an adjustment to expense of $66,659, as shown in the calculation below:

Table 4. Property Tax Adjustment

0.01303	2014 tax rate (per UG 288 Smith WP 2.04)
0.002	escalation factor used by Staff
0.01305	2015 forecasted tax rate (per Staff)
$184,700,000	2014 property value included in case (per UG 288 Smith WP 2.04)
$2,410,812	amount proposed by Staff
$2,477,471	amount included by Company in test year
$66,659	Staff Adjustment

[28] Exhibit Staff/802, Bahr/25. Also found on page 8 of the following site: http://www.oregon.gov/DAS/OEA/docs/economic/appendixa.pdf.

Issue 4, Wages, Salaries, and Incentives

Q. Please describe the Company's request associated with Wages, Salaries, and Incentives.

A. The Company proposes including in the test year approximately $8 million in wages and salaries, $0.4 million in overtime, and $0.55 million in incentive compensation expense and $0.56 million in capitalized incentive compensation. These amounts are found in the Company's workpapers 3.03 and 2.12, and in its response to Staff Data Request No. 224.[29]

Q. Please describe Staff's analysis regarding the Company's requested wages, salaries, and incentive costs.

A. The Commission typically uses Staff's three-year wage and salary model to estimate expenses for non-union wages and salaries.[30] The increases in payroll from the historic base year should be tied to the rate of inflation using the All-Urban CPI.[31] Rather than using All-Urban CPI for union wages, the Commission in the past has ordered that union payroll increases be tied to negotiated wage increases as set forth in the union contract.[32] Staff applied this model to the information the Company provided in its filing and responses to Staff data requests

For incentives, Commission policy traditionally disallows 100 percent of officers' bonuses, which are typically based on earnings.[33] It is also

[29] Exhibit Staff/802, Bahr/26-28.
[30] See e.g., Order No. 01-787.
[31] See Order 01-787 at 40; Order 99-697 at 43; Order 99-033 at 61; Order 95-322 at10.
[32] See Order 99-697 at 43.
[33] See Order 99-033 at 62; Order 97-171 at 74-76.

Commission policy to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders) and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[34]

Q. Does Staff propose an adjustment related to wages, salaries, and incentives?

A. Yes. Based on Staff's three-year wage and salary model, Staff proposes an adjustment primarily to incorporate the difference in escalation factors used by the Company and Staff. This results in an adjustment to wages and salaries expense of $62,000 and $5,000 to capital. The adjustment to overtime for both expense and capital is not significant. Staff proposes an adjustment for incentives of $288,000 in expenses and $278,000 in capital. The flow-through effect of these adjustments is an additional adjustment to payroll taxes of $17,000 and depreciation expense of $200. Details and calculations of Staff's adjustment can be found at Exhibit Staff/802, Bahr/29-35.

Q. Does Staff need to address any other issues relating to wages, salaries, and incentives?

A. Yes. Depending on the projects on which they are working, Avista employees charge time to various accounts, which are either picked up with other O&M accounts and included in labor expenses in a general rate case or to certain accounts that are picked up by tariff riders, such as that for Demand Side

[34] See Order 99-697 at 44-45; Order 99-033 at 62.

Management (DSM). These tariff riders, which include both fully loaded labor costs and non-labor costs, are addressed in proceedings separate from general rate cases.

As stated above, the labor costs included in the tariff riders are fully loaded, which means in addition to wage and salary costs, they also include things like medical benefits costs and incentive compensation. Staff has become aware that the adjustments recommended in rate cases for issues such as medical benefits or incentive compensation are not necessarily applied in other tariff filings. The opportunity exists, therefore, for a company to game the system by pushing more labor costs into tariff riders with unadjusted labor loadings from base rates. As this general rate case does not concern some of the tariff riders, Staff has no adjustment in this rate case, but recommends that the Commission direct the Company to apply adjustments made in rate cases to all of its tariff filings.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Brian Bahr
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance & Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Certificate of Public Management, Willamette University, Salem OR Bachelor of Science, Accountancy, Brigham Young University, Provo UT
EXPERIENCE:	Employed with the Oregon Public Utility Commission from March 2011 to present, currently serving as Senior Utility Analyst in the Rates, Finance, & Audit Section of the Energy Division. Employed by Modern Seouf Plastics in Alexandria, Egypt as a Managerial Intern from January 2010 to June 2010. Assisted in variety of duties including supervision of production facilities and staff, market analysis, budget forecasting, sales, and office administration. Employed by PricewaterhouseCoopers LLP in New York City as a Financial Assurance Associate from October 2007 to November 2009. Performed audits of various financial institutions, including investment banks, hedge funds, and insurance companies. Employed by TESRA, SA in Antofagasta, Chile as a Project Management Assistant from September 2005 to April 2006. Assisted in design process and implementation of rail road crossing and other civil engineering projects.

CASE: UG 288
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

October 16, 2015

Statind:DL Company:(Name:AVA

Ferc Acct	Ferc Acct I Service	Jurisdiction	Ending Balance SUM 201312	201401	201402	201403	201404	201405	201406	201407	201408	201409	201410	201411	201412	AMA
190150	ADFIT FA! CD	AA	(26,211,197)	(25,881,978)	(25,552,759)	(25,223,541)	(24,894,322)	(24,565,104)	(25,167,253)	(24,927,117)	(24,686,982)	(27,348,860)	(27,105,419)	(26,849,476)	(26,593,534)	(25,717,098)
		AN	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)	(769,300)
			(26,980,497)	(26,651,278)	(26,322,059)	(25,992,841)	(25,663,622)	(25,334,404)	(25,936,553)	(25,696,417)	(25,456,282)	(28,118,160)	(27,874,719)	(27,618,776)	(27,362,834)	(26,486,398)
228320	ACCUM PI ZZ	ZZ	80,704,270	79,287,603	77,870,936	87,454,269	86,037,602	84,620,935	96,004,270	94,970,937	93,937,604	103,404,270	102,370,937	101,284,540	100,198,144	91,474,593
																64,988,195
																8.702%
																$\boxed{5,655,273}$

Source: GL activity from Discoverer

1) Pension Asset - OR

Avista Corp
Summary - Working Capital (Not Combined)
For the Twelve Month Period Ended December 31, 2014 - Average of Monthly Averages Basis

4,739,320.90

Allocation Factor	Assigned Svc.Jur	Account	Account Description	Input Svc	Input Jur	Sum Averaged Amount	Less: Non-Operating	Operating ISWC	Allocation Factors Gas-South	GD-OR	GD-OR
1	GD.OR	144030	ACC PRV UNCOLL NET OF ACTUAL-D	GD	OR	(3,772.37)	($182.51)	($3,589.86)	100%	100%	(3,589.86)
1	GD.OR	144200	ACCUMULATED RETAIL WRITE-OFFS	GD	OR	11,242,439.79	$543,923.25	$10,698,516.54	100%	100%	10,698,516.54
1	GD.OR	144600	ACCUMULATED RETAIL REINSTATEME	GD	OR	(2,573,668.72)	($124,517.30)	($2,449,151.42)	100%	100%	(2,449,151.42)
1	GD.OR	144700	ACCUMULATED RETAIL RECOVERIES	GD	OR	(2,533,902.75)	($122,593.37)	($2,411,309.38)	100%	100%	(2,411,309.38)
1	GD.OR	165320	GAS IMBALANCE-AVISTA LDC	GD	OR	16,585.15	$802.41	$15,782.74	100%	100%	15,782.74
1	GD.OR	190200	ADFIT INJURY AND DAMAGE	GD	AS/OR	7,553.55	$365.45	$7,188.10	100%	100%	7,188.10
1	GD.OR	228200	ACCUM PROV FOR INJURY & DAMAGE	GD	AS/OR	(581,242.23)	($28,121.22)	($553,121.01)	100%	100%	(553,121.01)
1	GD.OR	228210	PAYMENT/REFUND INJURY & DAMAGE	GD	CA/OR	559,660.14	$27,077.06	$532,583.08	100%	100%	532,583.08
1	GD.OR	236250	MOTOR VEHICLE TAX-OREGON	ZZ	ZZ	0.00	$0.00	$0.00	100%	100%	0.00
1	GD.OR	236680	OR/CA TAXES ACCRUED BETC-OREGO	ZZ	ZZ	105,233.74	$5,091.34	$100,142.40	100%	100%	100,142.40
1	GD.OR	236690	OR REGULATORY BETC	ZZ	ZZ	34,911.00	$1,689.04	$33,221.96	100%	100%	33,221.96
1	GD.OR	242400	STATE COMMISSION FEE ACCRUED	GD	OR	139,024.89	$6,726.20	$132,298.69	100%	100%	132,298.69
1	GD.OR	242770	LOW INCOME ENERGY ASSIST	GD	OR	(50,901.88)	($2,462.70)	($48,439.18)	100%	100%	(48,439.18)
2	CD.AA	144200	ACCUMULATED RETAIL WRITE-OFFS	GD	CA	160,521.10	$7,766.21	$152,754.89	14.029%	100%	21,429.98
2	CD.AA	144600	ACCUMULATED RETAIL REINSTATEME	GD	CA	(80,198.40)	($3,880.10)	($76,318.30)	14.029%	100%	(10,706.69)
2	CD.AA	144700	ACCUMULATED RETAIL RECOVERIES	GD	CA	(61,131.61)	($2,957.62)	($58,173.99)	14.029%	100%	(8,161.23)
2	CD.AA	144990	ACC PROV FOR UNCOLLECTIBLES-RE	CD	AA	(45,300,686.02)	($2,191,703.66)	($43,108,982.36)	14.029%	100%	(6,047,759.14)
2	CD.AA	190810	ADFIT BAD DEBT RESERVE & WRITE	CD	AA	1,650,865.19	$79,870.92	$1,570,994.27	14.029%	100%	220,394.79
4	CD.AA	131100	CASH-US BANK	ZZ	ZZ	2,288,829.22	$110,736.41	$2,178,092.81	8.702%	100%	189,537.64
4	CD.AA	131110	CASH-WELLS FARGO	ZZ	ZZ	(2,656,306.30)	($128,515.41)	($2,527,790.89)	8.702%	100%	(219,968.36)
4	CD.AA	131120	CASH-PAYROLL	ZZ	ZZ	(320,102.75)	($15,486.97)	($304,615.78)	8.702%	100%	(26,507.67)
4	CD.AA	131140	CASH-WORKERS COMPENSATION	ZZ	ZZ	(29,742.96)	($1,439.00)	($28,303.96)	8.702%	100%	(2,463.01)
4	CD.AA	131170	CASH - AM&D (METALFX)	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	131400	CASH - CANADIAN ACCOUNT (USD)	ZZ	ZZ	22,268.78	$1,077.39	$21,191.39	8.702%	100%	1,844.07
4	CD.AA	134100	SPECIAL DEPOSITS-INTEREST RATE	ZZ	ZZ	9,166,666.67	$443,494.76	$8,723,171.91	8.702%	100%	759,090.42
4	CD.AA	134101	SPECIAL DEPOSITS-IR SWAP CONTRA	ZZ	ZZ	(8,980,833.33)	($434,503.91)	($8,546,329.42)	8.702%	100%	(743,701.59)
4	CD.AA	134120	OTHER SPECIAL DEPOSITS - NEWED	ZZ	ZZ	7,325,977.00	$354,439.90	$6,971,537.10	8.702%	100%	606,663.16
4	CD.AA	134122	OTHER SPECIAL DEPOSITS - MIZUH	ZZ	ZZ	3,420,320.55	$165,479.37	$3,254,841.18	8.702%	100%	283,236.28
4	CD.AA	135100	WORKING FUNDS-EMPLOYEE	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	135400	WORKING FUND-REAL ESTATE DEPT	ZZ	ZZ	10,000.00	$483.81	$9,516.19	8.702%	100%	828.10
4	CD.AA	135430	WORKING FUND-FLEET MANAGEMENT	ZZ	ZZ	5,000.00	$241.91	$4,758.09	8.702%	100%	414.05
4	CD.AA	136000	TEMPORARY CASH INVESTMENTS	ZZ	ZZ	7,665,254.42	$370,854.56	$7,294,399.86	8.702%	100%	634,758.68
4	CD.AA	136300	TEMP CASH INVEST-AFS SECURITIE	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	142100	CUST ACCT REC-RETAIL SERVICE	ZZ	ZZ	63,838,658.07	$3,088,593.85	$60,750,064.22	8.702%	100%	5,286,470.59
4	CD.AA	142350	CUST ACCT REC- NET PRESENTATIO	ZZ	ZZ	(4,159,145.26)	($201,224.63)	($3,957,920.63)	8.702%	100%	(344,418.25)
4	CD.AA	143020	GST	ZZ	ZZ	3,543,266.93	$171,427.67	$3,371,839.26	8.702%	100%	293,417.45
4	CD.AA	143025	HST	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	143050	OTHER ACCT REC-RETIREE DEDUCTI	ZZ	ZZ	(159,104.95)	($7,697.70)	($151,407.25)	8.702%	100%	(13,175.46)
4	CD.AA	143200	OTHER ACCT REC-OTHER MISC	ZZ	ZZ	69,235.77	$3,349.71	$65,886.06	8.702%	100%	5,733.40
4	CD.AA	143390	OTHER ACCT REC-WILMINGTON TRUS	ZZ	ZZ	4,595.66	$222.34	$4,373.32	8.702%	100%	380.57
4	CD.AA	143500	OTHER ACCT REC-MISCELLANEOUS	ZZ	ZZ	1,285,916.37	$62,214.24	$1,223,702.13	8.702%	100%	106,486.56
4	CD.AA	143510	CSS ACCOUNTS RECEIVABLES	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	143550	OTHER ACCT REC-DAMAGE CLAIMS	ZZ	ZZ	593,408.17	$28,709.83	$564,698.34	8.702%	100%	49,140.05
4	CD.AA	143900	OTHER ACCT REC-DEVELOPERS PROM	ZZ	ZZ	6,822.15	$330.06	$6,492.09	8.702%	100%	564.94
4	CD.AA	154100	PLANT MATERIALS & OPER SUPPLIE	ZZ	ZZ	24,717,855.76	$1,195,880.67	$23,521,975.09	8.702%	100%	2,046,882.27
4	CD.AA	154500	SUPPLY CHAIN RECEIVING INVENTO	ZZ	ZZ	4,322.61	$209.13	$4,113.48	8.702%	100%	357.95
4	CD.AA	154550	SUPPLY CHAIN AVERAGE COST VARI	ZZ	ZZ	(1,189.72)	($57.56)	($1,132.16)	8.702%	100%	(98.52)
4	CD.AA	154560	SUPPLY CHAIN INVOICE PRICE VAR	ZZ	ZZ	(245.06)	($11.86)	($233.20)	8.702%	100%	(20.29)
4	CD.AA	163000	STORES EXPENSE UNDISTRIBUTED	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	163200	STORES EXPENSE-SUPPLY CHAIN IN	ZZ	ZZ	4,549.66	$220.12	$4,329.54	8.702%	100%	376.76
4	CD.AA	165100	PREPAYMENTS-PREPAID INSURANCE	ZZ	ZZ	2,783,302.34	$134,659.64	$2,648,642.70	8.702%	100%	230,484.89
4	CD.AA	165110	PREPAYMENTS-MISC	ZZ	ZZ	10,739.67	$519.60	$10,220.07	8.702%	100%	889.35
4	CD.AA	165150	PREPAYMENTS-PREPAID LICENSE FE	ZZ	ZZ	4,465,176.91	$216,030.82	$4,249,146.09	8.702%	100%	369,760.69

Avista Corp
Summary - Working Capital (Not Combined)
For the Twelve Month Period Ended December 31, 2014 - Average of Monthly Averages Basis

4,739,320.90

Allocation Factor	Assigned Svc.Jur	Account	Account Description	Input Svc	Input Jur	Sum Averaged Amount	Less: Non-Operating	Operating ISWC	Allocation Factors Gas-South	GD-OR	GD-OR
4	CD.AA	165180	PREPAYMENTS-CUSTOMER BILLING S	ZZ	ZZ	50,180.04	$2,427.77	$47,752.27	8.702%	100%	4,155.40
4	CD.AA	165190	RESOURCE DEFERRED OPT EXPENSE	ZZ	ZZ	179,668.97	$8,692.61	$170,976.36	8.702%	100%	14,878.36
4	CD.AA	165191	RESOURCE DEFERRED OPT EXPENSE	ZZ	ZZ	(1,055,676.04)	($51,074.92)	($1,004,601.12)	8.702%	100%	(87,420.39)
4	CD.AA	165200	PREPAYMENTS-POSTAGE METERS	ZZ	ZZ	75,835.35	$3,669.01	$72,166.34	8.702%	100%	6,279.92
4	CD.AA	165550	PREPAYMENTS-WILMINGTON TRUST	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	171000	INTEREST & DIVIDENDS RECEIVABL	ZZ	ZZ	37,891.60	$1,833.24	$36,058.36	8.702%	100%	3,137.80
4	CD.AA	172500	RENTS RECEIVABLE-MISCELLANEOUS	ZZ	ZZ	248,283.48	$12,012.26	$236,271.22	8.702%	100%	20,560.32
4	CD.AA	172510	RENTS RECEIVABLE-ACCRUED	ZZ	ZZ	1,443,344.83	$69,830.82	$1,373,514.01	8.702%	100%	119,523.19
4	CD.AA	184260	PAYROLL BENEFITS CLEARING	ZZ	ZZ	11,155.21	$539.70	$10,615.51	8.702%	100%	923.76
4	CD.AA	184270	PAYROLL TAXES CLEARING	ZZ	ZZ	(342,114.31)	($16,551.92)	($325,562.39)	8.702%	100%	(28,330.44)
4	CD.AA	186180	PREPAID AIRPLANE LEASE EXPENSE	ZZ	ZZ	100,154.51	$4,845.60	$95,308.91	8.702%	100%	8,293.78
4	CD.AA	186205	PLANT ALLOC OF CLEARING JOURNA	ZZ	ZZ	2,378,271.49	$115,063.74	$2,263,207.75	8.702%	100%	196,944.34
4	CD.AA	186400	MISC DEFERRED DEBITS TREASURY	CD	AA	1,863.29	$90.15	$1,773.14	8.702%	100%	154.30
4	CD.AA	190150	ADFIT FAS87 UNFUNDED PENSION	CD/ZZ	AA/AN/ZZ	(26,486,398.12)	($1,281,444.96)	($25,204,953.16)	8.702%	100%	(2,193,335.02)
4	CD.AA	190830	ADFIT PAID TIME OFF	CD	AA	3,729,793.83	$180,452.07	$3,549,341.76	8.702%	100%	308,863.72
4	CD.AA	228210	PAYMENT/REFUND INJURY & DAMAGE	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	228300	ACCUM PROV FAS106 POST RET MED	ZZ	ZZ	(11,995,988.82)	($580,380.89)	($11,415,607.93)	8.702%	100%	(993,386.20)
4	CD.AA	228320	ACCUM PROV FAS87 ACCUM PEN COS	ZZ	ZZ	91,474,592.79	$4,425,654.82	$87,048,937.97	8.702%	100%	7,574,998.58
4	CD.AA	228330	HRA - RETIREE	ZZ	ZZ	(7,168,720.75)	($346,831.65)	($6,821,889.10)	8.702%	100%	(593,640.79)
4	CD.AA	228335	HRA - ACTIVE EMPLOYEES	ZZ	ZZ	(1,073,035.23)	($51,914.78)	($1,021,120.45)	8.702%	100%	(88,857.90)
4	CD.AA	228340	ACCUM PROV MED CLAIMS PAYABLE	ZZ	ZZ	(2,814,240.85)	($136,156.48)	($2,678,084.37)	8.702%	100%	(233,046.90)
4	CD.AA	232100	ACCTS PAY-GENERAL	ZZ	ZZ	(2,012,348.10)	($97,359.91)	($1,914,988.19)	8.702%	100%	(166,642.27)
4	CD.AA	232120	ACCTS PAY-PAYROLL OTHER	ZZ	ZZ	(328,157.05)	($15,876.65)	($312,280.40)	8.702%	100%	(27,174.64)
4	CD.AA	232135	ACCTS PAY-LDC GAS BROKER FEES	CD	AA	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	232160	ACCTS PAY-STAMPS	ZZ	ZZ	768.28	$37.17	$731.11	8.702%	100%	63.62
4	CD.AA	232200	ACCTS PAY-VOUCHERS	ZZ	ZZ	(12,147,242.81)	($587,698.75)	($11,559,544.06)	8.702%	100%	(1,005,911.52)
4	CD.AA	232300	ACCTS PAY-PAYROLL	ZZ	ZZ	(3,880,413.75)	($187,739.25)	($3,692,674.50)	8.702%	100%	(321,336.53)
4	CD.AA	232350	ACCTS PAY- NET PRESENTATION AC	ZZ	ZZ	4,159,145.26	$201,224.63	$3,957,920.63	8.702%	100%	344,418.25
4	CD.AA	232370	LIABILITY AWARD INCENTIVE ACCR	ZZ	ZZ	(999,279.69)	($48,346.40)	($950,933.29)	8.702%	100%	(82,750.22)
4	CD.AA	232380	ACCTS PAY-EMPLOYEE INCENTIVE P	ZZ	ZZ	(8,962,304.33)	($433,607.45)	($8,528,696.88)	8.702%	100%	(742,167.20)
4	CD.AA	232390	ACCTS PAY-SEVERANCE ACCRUAL	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	232400	ACCTS PAY-UNCLAIMED FUNDS	ZZ	ZZ	(91,205.88)	($4,412.65)	($86,793.23)	8.702%	100%	(7,552.75)
4	CD.AA	232650	ACCTS PAY-RESOURCE ACCOUNTING	ZZ	ZZ	(170,002.66)	($8,224.94)	($161,777.72)	8.702%	100%	(14,077.90)
4	CD.AA	232670	ACCTS PAY-RESOURCE TRANS FEE	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	232800	CUSTOMER REFUNDS PAYABLE-CSS	ZZ	ZZ	4,134.56	$200.04	$3,934.52	8.702%	100%	342.38
4	CD.AA	232820	CUSTOMER REFUNDS PAYABLE-CCB	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	236000	TAXES ACCRUED-FEDERAL	ZZ	ZZ	4,406,292.63	$213,181.93	$4,193,110.70	8.702%	100%	364,884.49
4	CD.AA	236050	TAXES ACCRUED - STATE	ZZ	ZZ	(5,014,551.11)	($242,610.23)	($4,771,940.88)	8.702%	100%	(415,254.30)
4	CD.AA	236100	TAXES OTHER THAN INC-WA/ID & O	ZZ	ZZ	(2,092.81)	($101.25)	($1,991.56)	8.702%	100%	(173.31)
4	CD.AA	236500	USE TAX ACCRUAL	ZZ	ZZ	(90,839.49)	($4,394.93)	($86,444.56)	8.702%	100%	(7,522.41)
4	CD.AA	237100	INTEREST ACCRUED - LT DEBT	ZZ	ZZ	(19,479,410.73)	($942,438.17)	($18,536,972.56)	8.702%	100%	(1,613,087.35)
4	CD.AA	237200	INTEREST ACCRUED - OTHER LIABI	ZZ	ZZ	(139,463.78)	($6,747.43)	($132,716.35)	8.702%	100%	(11,548.98)
4	CD.AA	237210	INTEREST ACCRUED - CUST DEPOSI	ZZ	ZZ	(1,771.64)	($85.71)	($1,685.93)	8.702%	100%	(146.71)
4	CD.AA	241000	PAYROLL TAX PAYABLE	ZZ	ZZ	(316,892.69)	($15,331.66)	($301,561.03)	8.702%	100%	(26,241.84)
4	CD.AA	241200	SALES TAX PAYABLE	ZZ	ZZ	(10.57)	($0.51)	($10.06)	8.702%	100%	(0.88)
4	CD.AA	241300	DIRECTORS WA B&O TAXES PAYABLE	ZZ	ZZ	(9,295.80)	($449.74)	($8,846.06)	8.702%	100%	(769.78)
4	CD.AA	242050	MISC LIAB-MARGIN CALL DEPOSIT	ZZ	ZZ	(1,368,333.33)	($66,201.67)	($1,302,131.66)	8.702%	100%	(113,311.50)
4	CD.AA	242051	MISC LIAB-MARGIN CALL DEPOSIT CONTRA	ZZ	ZZ	0.00	$0.00	$0.00	8.702%	100%	0.00
4	CD.AA	242090	SETTLEMENT PAYABLE	ZZ	ZZ	(198,333.33)	($9,595.61)	($188,737.72)	8.702%	100%	(16,423.96)
4	CD.AA	242095	MISC LIAB-MIRABEAU ACCRUED REN	ZZ	ZZ	(34,913.89)	($1,689.18)	($33,224.71)	8.702%	100%	(2,891.21)
4	CD.AA	242200	MISC LIAB-AUDIT EXP ACC	ZZ	ZZ	260,648.64	$12,610.51	$248,038.13	8.702%	100%	21,584.28
4	CD.AA	242700	MISC LIAB-PAYROLL EQLZTN	ZZ	ZZ	(17,593,422.04)	($851,191.69)	($16,742,230.35)	8.702%	100%	(1,456,908.89)
4	CD.AA	242900	ACCTS PAYABLE INVENTORY ACCRUA	ZZ	ZZ	(138,748.68)	($6,712.83)	($132,035.85)	8.702%	100%	(11,489.76)

Avista Corp
Summary - Working Capital (Not Combined)
For the Twelve Month Period Ended December 31, 2014 - Average of Monthly Averages Basis

4,739,320.90

Allocation Factor	Assigned Svc.Jur	Account	Account Description	Input Svc	Input Jur	Sum Averaged Amount	Less: Non-Operating	Operating ISWC	Allocation Factors: Gas-South	GD-OR	GD-OR
4	CD.AA	242910	ACCTS PAYABLE EXPENSE ACCRUAL-	ZZ	ZZ	(1,053,771.75)	($50,982.79)	($1,002,788.96)	8.702%	100%	(87,262.70)
4	CD.AA	283150	FAS 106-CURRENT	CD/ZZ	AA/ZZ	3,797,347.73	$183,720.42	$3,613,627.31	8.702%	100%	314,457.85
4	CD.AA	283152	FAS 106-CURRENT	CD	AA	330,279.81	$15,979.35	$314,300.46	8.702%	100%	27,350.43
4	CD.AA	283153	FAS 106-CURRENT	CD	AA	294,146.41	$14,231.17	$279,915.24	8.702%	100%	24,358.22
4	GD.AA	142510	CUST ACCT REC-UNBILLED REV GAS	ZZ	ZZ	17,263,637.79	$835,236.32	$16,428,401.47	30.918%	100%	5,079,333.17
4	GD.AA	142600	CUST ACCT REC-RESALE GAS	ZZ	ZZ	13,507,560.03	$653,512.59	$12,854,047.44	30.918%	100%	3,974,214.39
4	GD.AA	232130	ACCTS PAY-GAS SUPPLY TRANSACTI	ZZ	ZZ	(30,265,952.89)	($1,464,304.53)	($28,801,648.36)	30.918%	100%	(8,904,893.64)
4	GD.AA	232135	ACCTS PAY-LDC GAS BROKER FEES	ZZ	ZZ	(30.85)	($1.49)	($29.36)	30.918%	100%	(9.08)
4	GD.AA	232140	ACCTS PAY-GAS RESEARCH INSTITU	ZZ	ZZ	20,954.09	$1,013.78	$19,940.31	30.918%	100%	6,165.14
4	GD.AA	232545	ACCTS PAY-JACKSON PRAIRIE STOR	ZZ	ZZ	(284,676.94)	($13,773.03)	($270,903.91)	30.918%	100%	(83,758.07)
20	GD.OR	236100	TAXES OTHER THAN INC-WA/ID & O	GD	OR	(322,013.90)	($15,579.43)	($306,434.47)	100%	100%	(306,434.47)
Grand Total						**$97,957,808.89**	$4,739,320.90	$93,218,487.99			8,518,411.31

Less: Materials & Supplies	(2,047,121.41)
Less: Pension, Net of ADFIT	(5,381,663.56)
Working capital	1,089,626.34

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2014 and 2013 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 527,004	$ 584,619	$ 108,249	$ 132,541
Service cost	15,757	19,045	1,844	4,144
Interest cost	26,224	23,896	5,226	5,216
Actuarial (gain)/loss	97,128	(78,234)	18,714	(18,017)
Plan change	—	277	—	(10,788)
Transfer of accrued vacation	—	—	437	1,189
Benefits paid	(31,439)	(22,599)	(6,481)	(6,036)
Benefit obligation as of end of year	$ 634,674	$ 527,004	$ 127,989	$ 108,249
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 481,502	$ 406,061	$ 29,732	$ 25,288
Actual return on plan assets	55,974	52,502	1,580	4,444
Employer contributions	32,000	44,263	—	—
Benefits paid	(30,165)	(21,324)	—	—
Fair value of plan assets as of end of year	$ 539,311	$ 481,502	$ 31,312	$ 29,732
Funded status	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Unrecognized net actuarial loss	175,596	107,043	82,421	56,885
Unrecognized prior service cost	256	278	(10,379)	(707)
Prepaid (accrued) benefit cost	80,489	61,819	(24,635)	(22,339)
Additional liability	(175,852)	(107,321)	(72,042)	(56,178)
Accrued benefit liability	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Accumulated pension benefit obligation	$ 551,615	$ 464,432	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 58,276	$ 52,384
For fully eligible employees			$ 31,843	$ 24,320
For other participants			$ 37,870	$ 31,545
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 166	$ 180	$ (6,747)	$ (7,472)
Unrecognized net actuarial loss	114,138	69,578	53,574	43,988
Total	114,304	69,758	46,827	36,516
Less regulatory asset	(106,484)	(64,925)	(46,759)	(37,116)
Accumulated other comprehensive loss (income) for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,820	$ 4,833	$ 68	$ (600)
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	4.21%	5.10%	4.16%	5.02%
Discount rate for annual expense	5.10%	4.15%	5.02%	4.15%
Expected long-term return on plan assets	6.60%	6.60%	6.40%	6.35%
Rate of compensation increase	4.87%	4.96%		
Medical cost trend pre-age 65—initial			7.00%	7.00%
Medical cost trend pre-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2021	2020
Medical cost trend post-age 65—initial			7.00%	7.50%
Medical cost trend post-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2022	2021

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	$ 129	$ 155	$ 1,078	$ 1,518	$ 1,675	$ 1,747
Interest cost	17,682	16,249	17,598	3,521	3,215	4,166
Expected return on assets	(21,218)	(19,917)	(23,536)	(4,617)	(4,343)	(4,890)
Amortization of prior service cost (credit)	71	71	(46)	(1,393)	(1,457)	(1,438)
Recognized net actuarial loss	4,869	7,173	7,070	649	1,814	2,134
Curtailment gain	—	—	(1,023)	—	—	—
Amortization of net transition obligation	—	—	—	—	—	2,128
Net periodic benefit cost (credit), including amount capitalized	1,533	3,731	1,141	(322)	904	3,847
Less amount capitalized	388	727	937	(21)	164	910
Net periodic benefit cost (credit)	1,145	3,004	204	(301)	740	2,937
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	77,238	(60,173)	19,982	15,114	(30,461)	1,863
Prior service credit	—	—	—	—	—	(11,418)
Amortization of actuarial loss	(4,869)	(7,173)	(7,070)	(649)	(1,814)	(2,134)
Amortization of prior service (cost) credit	(71)	(71)	1,069	1,393	1,457	1,438
Amortization of net transition obligation	—	—	—	—	—	(2,128)
Total recognized in accumulated other comprehensive (income) loss	72,298	(67,417)	13,981	15,858	(30,818)	(12,379)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	$ 73,443	$ (64,413)	$ 14,185	$ 15,557	$ (30,078)	$ (9,442)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $7.1 million and $71,000, respectively. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $1.8 million and $1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	3.70%	4.53%	3.74%	4.48%
Expected return on plan assets	7.00%	7.00%	6.00%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	3.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	4.53%	3.65%	4.48%	3.67%
Expected return on plan assets	7.00%	7.00%	6.00%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	4.00%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2014, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to

In 2015, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $15 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2014, relating to the postretirement benefit plan. The entire amount represents $15 thousand of amortization of prior service cost.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003 and established a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2015	2016	2017	2018	2019	2020-2024
Expected benefit payments	$ 3,970	$ 4,040	$ 4,090	$ 4,160	$ 4,210	$ 21,310
Expected Medicare Part D subsidy receipts	390	430	470	520	560	3,560

Plan Assumptions

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all Idaho Power-sponsored pension and postretirement benefits plans:

	Pension Plan		SMSP		Postretirement Benefits	
	2014	2013	2014	2013	2014	2013
Discount rate	4.25%	5.20%	4.20%	5.10%	4.20%	5.15%
Rate of compensation increase[1]	4.30%	4.38%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.4%	6.8%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2014	12/31/2013	12/31/2014	12/31/2013	12/31/2014	12/31/2013

[1] The 2014 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.55% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all Idaho Power-sponsored pension and postretirement benefit plans:

	Pension Plan			SMSP			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate	5.20%	4.20%	4.90%	5.10%	4.15%	5.10%	5.15%	4.20%	5.05%
Expected long-term rate of return on assets	7.75%	7.75%	7.75%	—	—	—	7.25%	7.25%	7.25%
Rate of compensation increase	4.30%	4.38%	4.35%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	6.4%	6.8%	6.5%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.4 percent in 2014 and is assumed to decrease gradually to 5.1 percent by 2093. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2014 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$ 325	$ (241)
Effect on accumulated postretirement benefit obligation	3,426	(2,657)

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions. Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	4.71%	3.84%	4.51%	4.45%	3.56%	4.33%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	8.00%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	3.85%	4.73%	3.85%	3.74%	4.45%	3.56%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2014 was 8.00% for pre-65 and 11.75% for post-65 populations. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2022.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable from the Company. A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$ 62	$ (55)
Effect on the accumulated postretirement benefit obligation	1,260	(965)

The Company adopted a new set of mortality tables for its plans beginning with 2014. The tables were released in October 2014 by the Society of Actuaries' Retirement Plans Experience Committee and project a mortality improvement, thereby increasing benefit plan liabilities.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans, and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2013	$ 13,907	$ 1,895
2014	12,077	1,871
2015 (estimated)	16,567	1,848
Benefit Payments:		
2012	18,195	1,971
2013	18,855	1,895
2014	19,932	1,871
Estimated Future Benefit Payments:		
2015	20,315	1,848
2016	20,993	1,918
2017	21,784	1,955
2018	22,799	2,007
2019	24,162	2,075
2020-2024	137,839	10,412

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2014	2013	2012	2014	2013	2012
Benefit obligations as of December 31:						
Discount rate	4.00%	4.80%	4.05%	3.90%	4.90%	4.10%
Rate of compensation increase	2.75	3.00	3.00	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.80%	4.05%	4.90%	4.90%	4.10%	4.95%
Expected return on plan assets	7.50	7.50	7.50	7.50	7.50	7.50
Rate of compensation increase	3.00	3.00	3.50	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the asset allocation and return assumptions for each asset class based on forward-looking views of the financial markets and historical performance.

	2014	2013
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.00%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2019

A one percentage-point change in assumed healthcare cost trend rates would have the following effects (in millions):

	Increase (Decrease)	
	One Percentage-Point Increase	One Percentage-Point Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2014	$ 3	$ (2)
Other postretirement benefit obligation as of December 31, 2014	—	—

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2015. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding policy for its other postretirement benefit plan is to generally contribute an amount equal to the net periodic benefit cost, subject to tax deductibility limitations and other considerations.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, continued

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2014	2013	2014	2013	2014	2013
Assumptions used:						
Discount rate for benefit obligation	4.02%	4.84%	3.07% - 4.10%	3.46% - 4.96%	4.02%	4.84%
Discount rate for benefit cost	4.84%	4.24%	3.46% - 4.96%	2.77% - 4.13%	4.84%	4.24%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	7.50%	6.37%	6.46%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	8.25%	6.46%	5.89%	N/A	N/A

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* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Service cost	$ 15	$ 17	$ 14	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	34	30	31	4	3	3	1	1	1
Expected return on plan assets	(39)	(40)	(41)	(2)	(1)	(1)	—	—	—
Amortization of prior service cost	—	—	—	1	1	1	—	—	—
Amortization of net actuarial loss	17	24	17	1	1	1	1	1	1
Net periodic benefit cost	$ 27	$ 31	$ 21	$ 6	$ 6	$ 6	$ 2	$ 2	$ 2

PGE estimates that $23 million will be amortized from AOCL into net periodic benefit cost in 2015 , consisting of a net actuarial loss of $20 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million for other postretirement benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	05/26/2015
CASE NO.:	UG 288	WITNESS:	Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Rich Stevens
TYPE:	Data Request	DEPT:	Finance
REQUEST NO.:	Staff – 147	TELEPHONE:	(509) 495-2998
		EMAIL:	rich.stevens@avistacorp.com

REQUEST:

With regard to the Company's responses to Staff Data Requests Nos. 59 and 60, please provide a narrative description explaining the amount of discretion the Company has in determining the inputs (eg. expected rate of return on plan assets and discount rate) used in the calculation of pension expense.

RESPONSE:

The assumptions for the expected rate of return and the discount rate are prescribed by financial accounting standards, specifically Accounting Standards Codification 715. The Company's application of these accounting standards is reviewed by the independent auditors to determine compliance with generally accepted accounting principles applied on a consistent basis. These standards limit management's discretion.

The expected rate of return on plan assets is a forward-looking estimate of the returns that can be expected from the assets held by the benefit plan. Avista has used the same method consistently from year to year. The expected return on assets is affected by the asset allocation among investment types and by the expected returns for each type of investment. The Company determines how to allocate plan assets and then uses this allocation to weight components of the expected return on assets. The Company has a choice of the time horizon for expected returns. Avista's expected returns are based on a 10-year horizon of capital market assumptions. The Company obtains capital market assumptions of expected returns on various asset types or based on Avista's specific investment portfolio from three external parties who are investment advisors or actuaries and the Company has used inputs from the same sources annually. Market return outlook from each external party varies from year to year but such variations are not a product of management discretion.

According to ASC 715, the discount rate may be based on the rates implicit in current annuity rates or available rates on high-quality corporate bond yields. For Avista, the discount rate is based on high-quality corporate bond yields on the last day of the year for a set of bonds that have cash flows that closely match Avista's benefit obligations. The selected bonds are identified by a model developed by the Company's actuaries, which is a consistent practice from year to year. The Company validates the bond information selected in the discount rate bond model but the Company does not exercise selective discretion.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/11/2015
CASE NO:	UG 288	WITNESS:	Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Rich Stevens
TYPE:	Data Request	DEPT:	Finance
REQUEST NO.:	Staff – 204 Supplemental	TELEPHONE:	(509) 495-4330
		EMAIL:	rich.stevens@avistacorp.com

REQUEST:

This request regards the Company's response to Staff Data Request No. 147. Using information found in utility companies' annual 10k reports found online, Staff compiled the following table:

Expected Rate of Return used in FAS 87 calculations

Company	2013	2014
Avista	6.6%	6.6%
Cascade	7%	7%
Idaho Power	7.75%	7.75%
NW Natural	7.5%	7.5%
PacifiCorp	7.5%	7.5%
PGE	8.25%	7.5%
AVERAGE	7.43%	7.31%

Given the information in the table above, please justify the Company's use of 6.6 percent for its expected return on assets input in the FAS 87 calculation.

RESPONSE:

The expected return on assets for Avista's Retirement Plan was determined based on a weighted calculation of the Avista Retirement Plan investment allocation and expected returns for each class of assets, consistent with ASC 715 (formerly FAS 87). Avista uses expected return inputs from independent investment advisors to determine expected return, not a peer comparison against expectations by other utilities. Each company should determine an appropriate expected return on its pension assets based on the investment profile of its own plan. Avista has not undertaken an analysis of pension plans at other utilities or their method of estimating expected returns.

SUPPLEMENTAL RESPONSE:

Avista's expected return on assets is driven in large part by the investment mix among assets in the Retirement Plan. In 2014, a liability-driven investment philosophy was implemented to strengthen the correlation between Retirement Plan obligations and Retirement Plan assets. The obligations for benefit payments represent a future liability, which is valued under GAAP based upon the end of year weighted average discount rate of a model bond portfolio that would provide cash flows equivalent to the benefit obligations. To match these obligations better, the asset allocation was shifted into a higher fixed income level than that Retirement Plan held prior to 2014. Avista moved its Retirement Plan assets from a 31% fixed income allocation to 58% fixed income allocation during 2014. While fixed income investments typically have lower expected returns than equity investments, their changes in value tend to correlate well to the nature of obligations in the pension plan, and the result is less volatility in funded levels of the Retirement Plan and less volatility in annual pension expense. Other companies may have significantly different funded status for their pension obligations and significantly different investment philosophies and, hence, their expected return on assets would be derived from their situations. Return on assets should not be examined in isolation from other aspects of a pension plan to understand the impact on current and future costs of the benefit obligations.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	05/28/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith/Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Rich Stevens
TYPE:	Data Request	DEPT:	Finance
REQUEST NO.:	Staff – 143	TELEPHONE:	(509) 495-4330
		EMAIL:	rich.stevens@avistacorp.com

REQUEST:

With regard to Avista/500, Smith/17, lines 1-4, please provide the revised pension forecast provided by Towers Watson as of May 2015.

RESPONSE:

Please see Staff_DR_143 Attachment A.

Retirement Plan for Employees of Avista Corporation
Actual 2014 and Estimated 2015-2019 Pension Expense
Based on March 31, 2015 Assets and December 31, 2014 Assumptions
2015-2019 Expected Return on Assets of 5.30%

	2014	2015	2016	2017	2018	2019
Discount Rate	5.10%	4.21%	4.21%	4.21%	4.21%	4.21%
Expected Return on Assets	6.60%	5.30%	5.30%	5.30%	5.30%	5.30%
Expected Contributions*	32,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000
Expected Benefit Payments	30,200,000	26,500,000	27,600,000	28,600,000	29,800,000	31,300,000
1. Assets	481,500,000	540,600,000	557,900,000	571,200,000	584,100,000	596,600,000
2. Accumulated Benefit Obligation	441,900,000	526,600,000	542,000,000	557,600,000	574,600,000	591,300,000
3. Projected Benefit Obligation	501,100,000	604,800,000	623,600,000	642,300,000	660,800,000	679,000,000
4. ABO Funded Status (1. / 2.)	109.0%	102.7%	102.9%	102.4%	101.7%	100.9%
5. PBO Funded Status (1. / 3.)	96.1%	89.4%	89.5%	88.9%	88.4%	87.9%
1. Service Cost	15,700,000	19,900,000	20,100,000	20,100,000	20,200,000	20,100,000
2. Interest Cost	25,000,000	24,900,000	25,700,000	26,400,000	27,200,000	27,900,000
3. Expected Return on Assets	(32,100,000)	(28,300,000)	(29,200,000)	(29,900,000)	(30,500,000)	(31,100,000)
Amortizations						
4. - Net Transition Obligation	0	0	0	0	0	0
5. - Net Prior Service Cost	0	0	0	0	0	0
6. - Net Gain/Loss	3,800,000	8,100,000	7,100,000	6,700,000	5,900,000	5,500,000
7. Net Periodic Pension Expense	12,400,000	24,600,000	23,700,000	23,300,000	22,800,000	22,400,000

* Contributions assumed deposited in equal installments on March 15, June 15, and September 15. Assuming annual contributions of $12M for 2015-2019.
Note, all projected liabilities and results are based on 1/1/2014 data. New entrants are assumed to replace participants leaving active status. The plan is assumed to be closed to Non-union employees hired on or after 1/1/2014.

Assumptions:
- *-Mortality Assumption: Same as 12/31/2014 disclosure for 2015-2019.*
- *-2016-2019 Assets projected from 3/31/2015 asset value of $548.6m provided by Avista.*
- *-Expected Return on Assets: 5.30% for 2015-2019*
- *-Average future working lifetime in 2014 is 13.0 years*
- *-Discount Rate Assumption for 2015-2019: Discount rate from 12/31/2014 disclosure*

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	10/01/2015
CASE NO:	UG 288	WITNESS:	Mark Thies
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 303	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

Please provide any comparables or other support the Company has available demonstrating the reasonableness or comparability of the Company's Expected Return on Pension Assets used to calculated pension and post retirement expense

RESPONSE:

The Company's expected return on assets is driven in large part by the investment mix among assets in the Retirement Plan. At lower levels of funding, equity investments are typically weighted more heavily in the investment mix in order to capture the highest returns and increase the funding status. The probability of a higher return on assets, which could result in a higher funded status, is weighed against the potential risks associated with volatility over time. At higher levels of funding, however, the objective shifts toward <u>maintaining</u>, not increasing the plans' funded status. The implementation of a "derisking strategy" whereby a portion of the overall portfolio is transferred from equity investments to fixed income investments, aids in the reduction of risk and volatility and strengthens the correlation between the Retirement Plan Obligations and the Retirement Plan assets.

With a January 1, 2014 funding level of approximately **96%**[1], the Company implemented a derisking strategy and moved from a 31% fixed income allocation to a 58% fixed income allocation during 2014. This investment mix, together with lower market return expectations for various investment classes, results in an expected return on assets of approximately 5.3% for 2015. As noted in the Company's response to Staff_DR_204 Supplemental

> "Other companies may have significantly different funded status for their pension obligations and significantly different investment philosophies and, hence, their expected return on assets would be derived from their situations."

By contrast, Idaho Power Pension Plan assets in comprised of approximately 67% funded with a 24% fixed asset investments and an expected return on assets of approximately 7.75% for 2014. Pacificorp is approximately 83% funded with 33-37% fixed income allocation and an expected return on assets of approximately 7.5%. This illustrates what the different funded status and

---

[1] Excluding Executive Supplemental Executive Retirement Program (SERP).

investment philosophies of individual companies makes it difficult to compare expected return on assets between companies.

Idaho Power[2] and NW Natural[3] explain that expected returns are derived from historic returns of similar asset classes. Avista estimates returns for its plan primarily based on view of future expected returns while keeping awareness of historic returns. In light of continued low interest rates and reduced expectations for equity returns over the long run, Avista believes its' estimate of expected returns are reasonable.

A recent report published by Wilshire Consulting "2015 Report on Corporate Pension Funding Levels" dated April 2, 2015 lends credence to the point that an expected rate of return can vary from company to company based on individual asset allocation and further suggested that an expected return on assets of 7.3% in 2014 maybe too high:

> "Although the median expected return on plan assets assumptions has fallen during the past thirteen years, from 9.5% in 2000 to 7.3% in 2014, many pension accounting critics believe that this assumption is still too high. Wilshire Consulting's long-term forecast for the return on corporate pension assets is approximately ***5.3%,*** based on the average asset allocation of corporate pension plans as noted in the companies' 10-Ks and or current capital market return and risk assumptions (summarized below). ***However, individual pension plan expected returns will vary considerable depending upon their unique asset allocation."*** emphasis added

The expected return on assets utilized by the Company is developed based on the asset allocation advice of the Company's independent pension investment advisors and expected future returns developed by three independent investment advisors.

[2] IDACORP 10-K, page 70 "Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the yield on the Moody's AA Corporate Bond Index".

[3] NW Natural 10-K, Page 70 "In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plans' assets are invested and the target asset allocation of plan assets.

Year	Company	Benefit Obligation	Fair Value of Plan Assets	Amount Underfunded	% Funded
2013	nwn	362.4	267.1	95.3	74%
2014	nwn	451.2	279.2	172	62%
2013	avista	527	482	45	91%
2014	avista	635	539	96	85%
2013	cascade	403	335	68	83%
2014	cascade	475	354	121	75%
2013	IPC	695	545	150	78%
2014	IPC	845	560	285	66%
2013	Pac	1230	1171	59	95%
2014	Pac	1378	1146	232	83%
2013	PGE	705	596	109	85%
2014	PGE	777	591	186	76%

Year	Company	% Funded	EROA
2013	avista	91.37%	6.60%
2013	cascade	83.13%	7.00%
2013	Idaho Power	78.42%	7.75%
2013	NW Natural	73.70%	7.50%
2013	PacifiCorp	95.20%	7.50%
2013	PGE	84.54%	8.25%
2014	avista	84.97%	6.60%
2014	cascade	74.55%	7.00%
2014	Idaho Power	66.25%	7.75%
2014	NW Natural	61.88%	7.50%
2014	PacifiCorp	83.16%	7.50%
2014	PGE	76.06%	7.50%

Correlation Coefficient **-0.29**

THE KAISER FAMILY FOUNDATION -AND- HEALTH RESEARCH & EDUCATIONAL TRUST

Employer Health Benefits

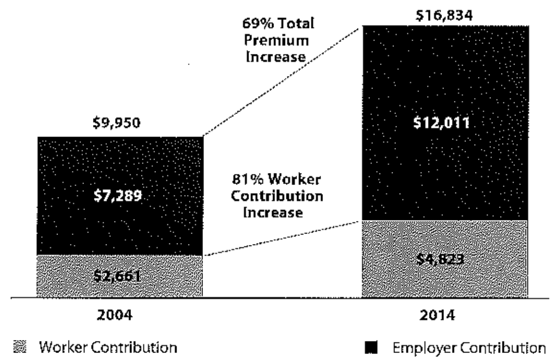
2014 Summary of Findings

Employer-sponsored insurance covers about 149 million nonelderly people.[1] To provide current information about employer-sponsored health benefits, the Kaiser Family Foundation (Kaiser) and the Health Research & Educational Trust (HRET) conduct an annual survey of private and nonfederal public employers with three or more workers. This is the sixteenth Kaiser/HRET survey and reflects employer-sponsored health benefits in 2014.

The key findings from the survey, conducted from January through May 2014, include a modest increase in the average premiums for family coverage (3%). Single coverage premiums are 2% higher than in 2013, but the difference is not statistically significant. Covered workers generally face similar premium contributions and cost-sharing requirements in 2014 as they did in 2013. The percentage of firms (55%) which offer health benefits to at least some of their employees and the percentage of workers covered at those firms (62%) are statistically unchanged from 2013. The percentage of covered workers enrolled in grandfathered health plans - those plans exempt from many provisions of the Affordable Care Act (ACA) - declined to 26% of covered workers from 36% in 2013. Perhaps in response to new provisions of the ACA, the average length of the waiting period decreased for those with a waiting period and the percentage with an out-of-pocket limit increased. Although employers continue to offer coverage to spouses, dependents and domestic partners, some employers are instituting incentives to influence workers' enrollment decisions, including nine percent of employers who attach restrictions for spouses' eligibility if they are offered coverage at another source, or nine percent of firms who provide additional compensation if employees do not enroll in health benefits.

EXHIBIT A

Average Annual Health Insurance Premiums and Worker Contributions for Family Coverage, 2004–2014



SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2004–2014.

HEALTH INSURANCE PREMIUMS AND WORKER CONTRIBUTIONS

In 2014, the average annual premiums for employer-sponsored health insurance are $6,025 for single coverage and $16,834 for family coverage. The average family premium rose 3% over the 2013 average premium. Single coverage premiums rose 2% in 2014 but are not statistically different than the 2013 average premium. During the same period, workers' wages increased 2.3% and inflation increased 2%. Over the last ten years, the average premium for family coverage has increased 69% (Exhibit A). Premiums have increased less quickly over the last five years (2009 to 2014), than the preceding five year period (2004 to 2009) (26% vs. 34%).

Average premiums for high-deductible health plans with a savings option (HDHP/SOs) are lower than the overall average for all plan types for both single and family coverage (Exhibit B), at $5,299 and $15,401, respectively. There are important differences in premiums by firm size: the average premium for family coverage is lower for covered workers in small firms (3–199 workers) than for workers in larger firms ($15,849 vs. $17,265).

Premiums vary significantly around the averages for single and family coverage, resulting from differences in benefits, cost sharing, covered populations, and geographical location. Twenty percent of covered workers are in plans with an annual total premium for family coverage of at least $20,201 (120% of the average family premium), and 20% of covered workers are in plans where the family premium is less than $13,467 (80% of the average family premium). The distribution is similar around the average single premium (Exhibit C).

Most often, employers require that workers make a contribution towards the cost of the premium. Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2013. Workers in small firms (3–199 workers) contribute a lower average percentage for single coverage compared to workers in larger firms (16% vs. 19%), but they contribute a higher average percentage for family coverage (35% vs. 27%). Workers in firms with a higher percentage of lower-wage workers (at least 35% of workers earn $23,000 or less) contribute higher percentages of the premium for single coverage (27% vs. 18%) and for family coverage (44% vs. 28%) than workers in firms with a smaller share of lower-wage workers.

As with total premiums, the share of the premium contributed by workers varies considerably among firms. For single coverage, 57% of covered workers are in plans that require them to make a contribution of less than or equal to a quarter of the total premium, 2% are in plans that require a contribution of more

Adjustment No. 2.04
Workpaper Ref. G-FPT-1

AVISTA UTILITIES
Property Tax Adjustment
2014 Test Year, 2016 Rate Year

	Gas	
Oregon		
Test Year Expense (Accrual per Results by State (Situs))	2,338,388	G-PFT-2
Estimated 2016 Expense	2,477,471	G-PFT-3
Total Adjustment	139,083	

Note: The purpose of the property tax adjustment is to look at future expense that will be paid. In this test year we looked at what will be paid in 2016.

Property tax estimates are developed by taking the last known value assessments from each state, and the average of the last known levy rates, adding 2014 plant additions, less depreciation, to the values, and then applying a small escalator to the levy rates to reflect their general increasing trend.

Prep by: ____________

Date: 10/8/2015

Mgr. Review: __________

Adjustment No. 2.04
Workpaper Ref. G-PFT-2

Period	Currency	PTD	YTD	
201401	USD	176,647.23	176,647.23	
201402	USD	176,647.23	353,294.46	
201403	USD	176,647.23	529,941.69	
201404	USD	176,647.23	706,588.92	
201405	USD	176,647.23	883,236.15	
201406	USD	176,647.22	1,059,883.37	
201407	USD	185,646.00	1,245,529.37	
201408	USD	185,646.00	1,431,175.37	
201409	USD	230,208.00	1,661,383.37	
201410	USD	230,208.00	1,891,591.37	
201411	USD	230,208.00	2,121,799.37	
201412	USD	216,588.50	2,338,387.87	G-PFT-1

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Date: 10/8/2015

Prep by: ____________

Mgr. Review: __________

Adjustment No. 2.04
Workpaper Ref. G-PFT-3

REVISED as of 09/09/2014 **REVISED 2013/2014 with Actual 2014 Assessments**

	in thousands		in thousands		in thousands	in thousands
BOOK VALUE @ DEC	2012		2013		2014	2015
YEAR ASSESSED	2013		2014		2015	2016
YEAR TAX ACCRUED	**2013**		**2014**		**2015**	**2016**
YEAR TAX PAYABLE (Oregon & California)	2013-2014		2014-2015		2015-2016	2016-2017
	2013 ACTUALS		2014 Estimate		2015 Estimate	2016 Estimate
OREGON - GAS	13/14 Actual		14/15 Estimate		15/16 Estimate	16/17 Estimate
HIST COST OREGON						
ESTIMATED STATE VALUE	168,937		184,700		184,700	184,700
ADD : NET ADDITIONS TO PLANT					0	0
LESS : DEPR EST					0	0
TAXABLE PERCENTAGE	100.0000%		100.0000%		100.0000%	100.0000%
STATE ALLOCATION %	100.0000%		100.0000%		100.0000%	100.0000%
STATE VALUE	168,937		184,700		184,700	184,700
Adjustments:						
	100.00%		100.00%		100.00%	100.00%
GROSS ASSESSED VALUE	168,937		184,700		184,700	184,700
RATIO	1.000		1.000		1.000	1.000
ASSESSED VALUE	168,937		184,700		184,700	184,700
TAX RATE	0.01265	3.0%	0.01303	2.0%	0.01341	0.01381
TAX	2,137		2,406		2,477	2,551

Note: Note: Property tax estimates are developed by taking the last known value assessments from each state, and the average of the last known levy rates, adding 2014 plant additions, less depreciation, to the values, and then applying a small escalator to the levy rates to reflect their general increasing trend.

Prep by: ___________

1) 2014 Forecast Property Tax Adjustment
Page 3 of 3

Date: 10/8/2015 Mgr. Review:__________

	in thousands		in thousands		in thousands
BOOK VALUE @ DEC	2008		2009		2010
YEAR ASSESSED	2009		2010		2011
YEAR TAX ACCRUED	**2009**		**2010**		**2011**
YEAR TAX PAYABLE (oregon & california)	2009-2010		2010-2011		2011-2012
OREGON - GAS	09/10 Actual		10/11 Estimate		11/12 Estimate
HIST COST OREGON					
ESTIMATED STATE VALUE	129,100		130,100		130,100
ADD : NET ADDITIONS TO PLANT – 2009 ADDITIONS.			0		30,506
LESS : DEPR EST			0		-15,300
TAXABLE PERCENTAGE			100.0000%		100.0000%
STATE ALLOCATION %	100.0000%		100.0000%		100.0000%
STATE VALUE	129,100		130,100		145,306
Adjustments:	631				
	100.000%		100.00%		100.00%
GROSS ASSESSED VALUE	129,731		130,100		145,306
RATIO	99.995%		1.000		1.000
ASSESSED VALUE	129,725		130,100		145,306
TAX RATE	0.01270905	3%	0.01309	3%	0.01348
TAX	1,649		1,703		1,959 ✓

F4
5

Adjustment No. 2.04
Workpaper Ref. G-PFT-4

Avista Corporation

As of June 6, 2013
2013 and 2014 Forecasts from January 2013

OREGON - GAS		11/12 Actual		12/13 Actual	13/14 Estimate		14/15 Estimate	14/15 Estimate
				Plant Balance as of 12/31/2011	Plant Balance as of 12/31/2012		Forecasted Plant Balance as of 12/31/2013 - Not used	
HIST COST OREGON								
ESTIMATED STATE VALUE		142,400		160,600	160,600		166,390	166,390
ADD : NET ADDITIONS TO PLANT					9,963		6,793	
LESS : DEPR EST					-4,173		-4,200	
TAXABLE PERCENTAGE		100.0000%		100.0000%	100.0000%		100.0000%	100.0000%
STATE ALLOCATION %		100.0000%		100.0000%	100.0000%		100.0000%	100.0000%
STATE VALUE		142,400		160,600	166,390		168,983	166,390
Adjustments:								
		100.00%		100.00%	100.00%		100.00%	100.00%
GROSS ASSESSED VALUE		142,400		160,600	166,390		168,983	166,390
RATIO		1.000		1.000	1.000		1.000	1.000
ASSESSED VALUE		142,400		160,600	166,390		168,983	166,390
TAX RATE	-0.63%	0.012577	0.53%	0.01264	0.01277	2.0%	0.01303	0.01303
TAX		1,791		2,031	2,125		2,201	2,167 G-PFT-2

(Not used - see Capital Additions adjustments (2.06 & 2.07) for property tax on 2013 and 2014 additions.

Property Tax on plant balance at 12/31/2012, to be expensed in 2014.

Note: Property tax estimates are developed by taking the last known value assessments from each state, and the average of the last known levy rates, adding 2012 plant additions, less depreciation, to the values, and then applying a small escalator to the levy rates to reflect their general increasing trend.

Prep by: ___________

Date: 10/8/2015 Mgr. Review: ___________

Sept 2015 - Other Economic Indicators

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	15,020.6	15,369.2	15,710.3	16,085.6	16,447.2	16,950.2	17,408.8	17,846.9	18,295.6	18,761.3	19,225.5	19,665.9
% Ch	1.6	2.3	2.2	2.4	2.2	3.1	2.7	2.5	2.5	2.5	2.5	2.3
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	103.3	105.2	106.7	108.3	109.5	111.6	113.7	115.7	117.8	120.0	122.4	124.9
% Ch	2.1	1.8	1.5	1.5	1.1	1.9	1.8	1.8	1.8	1.9	2.0	2.1
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	104.1	106.1	107.3	108.8	109.1	110.7	112.7	115.0	117.2	119.2	121.5	124.1
% Ch	2.5	1.8	1.2	1.3	0.3	1.4	1.8	2.0	2.0	1.7	1.9	2.1
CPI, Urban Consumers, 1982-84=100												
Portland-Salem, OR-WA	224.6	229.8	235.5	240.4	241.2	245.6	250.9	256.6	262.1	267.3	273.1	279.4
% Ch	2.9	2.3	2.5	2.1	0.3	1.8	2.2	2.3	2.1	2.0	2.2	2.3
U.S.	224.9	229.6	233.0	236.7	237.1	241.4	246.9	253.2	259.3	264.4	270.4	277.4
% Ch	3.1	2.1	1.5	1.6	0.2	1.8	2.3	2.5	2.4	2.0	2.3	2.6
Oregon Average Wage												
Rate (Thous $)	45.2	46.6	47.4	48.9	50.5	52.6	54.8	57.1	59.5	61.9	64.3	66.7
% Ch	3.2	3.2	1.8	3.1	3.2	4.2	4.2	4.2	4.2	4.1	3.9	3.7
U.S. Average Wage												
Wage Rate (Thous $)	50.3	51.7	52.2	53.6	55.0	56.9	58.9	61.2	63.7	66.2	68.8	71.4
% Ch	2.8	2.7	1.0	2.6	2.6	3.4	3.7	3.8	4.0	3.9	3.9	3.9
Housing Indicators												
FHFA Oregon Housing Price Index												
1980 Q1=100	347.9	346.9	372.2	406.0	441.6	478.6	499.3	517.3	535.6	554.8	574.3	594.2
% Ch	(6.9)	(0.3)	7.3	9.1	8.8	8.4	4.3	3.6	3.5	3.6	3.5	3.5
FHFA National Housing Price Index												
1980 Q1=100	312.3	312.0	324.9	346.2	370.8	382.6	394.2	403.5	412.9	424.4	436.9	453.5
% Ch	(3.7)	(0.1)	4.1	6.6	7.1	3.2	3.0	2.4	2.3	2.8	3.0	3.8
Housing Starts												
Oregon (Thous)	8.0	10.9	14.2	15.6	14.9	17.9	20.8	22.6	23.1	23.7	24.1	24.0
% Ch	5.2	35.7	31.2	9.5	(4.1)	19.8	16.4	8.3	2.3	2.5	1.8	(0.2)
U.S. (Millions)	0.6	0.8	0.9	1.0	1.1	1.3	1.5	1.5	1.6	1.6	1.6	1.6
% Ch	4.5	28.1	18.4	7.8	10.3	19.3	10.4	4.3	3.4	2.5	(0.3)	0.1
Other Indicators												
Unemployment Rate (%)												
Oregon	9.4	8.8	7.8	7.0	5.7	5.8	5.4	5.6	5.6	5.5	5.4	5.5
Point Change	(1.1)	(0.7)	(1.0)	(0.8)	(1.3)	0.0	(0.3)	0.1	0.0	(0.2)	(0.0)	0.0
U.S.	8.9	8.1	7.4	6.2	5.4	5.1	5.0	5.1	5.1	5.0	5.0	5.0
Point Change	(0.7)	(0.9)	(0.7)	(1.2)	(0.7)	(0.3)	(0.1)	0.1	0.0	(0.0)	(0.0)	0.0
Industrial Production Index												
U.S, 2002 = 100	93.6	97.1	99.9	104.1	105.7	109.3	113.2	116.4	119.5	122.6	125.4	128.2
% Ch	3.3	3.8	2.9	4.2	1.5	3.4	3.5	2.8	2.7	2.6	2.3	2.2
Prime Rate (Percent)	3.3	3.3	3.3	3.3	3.3	4.2	5.7	6.5	6.5	6.5	6.5	6.5
% Ch	0.0	0.0	0.0	0.0	2.5	24.9	36.9	14.1	0.0	0.0	0.0	0.0
Population (Millions)												
Oregon	3.86	3.89	3.93	3.97	4.02	4.06	4.11	4.16	4.21	4.26	4.31	4.36
% Ch	0.6	0.7	0.9	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
U.S.	312.3	314.5	316.7	319.0	321.7	324.3	326.9	329.5	332.2	334.8	337.4	340.0
% Ch	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Timber Harvest (Mil Bd Ft)												
Oregon	3,649.0	3,749.0	4,199.0	4,126.0	4,479.7	4,735.9	4,708.8	4,683.1	4,681.9	4,662.5	4,643.3	4,650.5
% Ch	13.1	2.7	12.0	(1.7)	8.6	5.7	(0.6)	(0.5)	(0.0)	(0.4)	(0.4)	0.2

Adjustment No. 3.03

AVISTA UTILITIES
Calculation of PUC wage formula

Explanation: Staff's proposal adjusts test period wages and salaries in accordance with guidelines followed in previous rate cases. Hence, staff allows wages and salaries to increase based on published CPI projections, and then allows the company to share 50/50 a 10% band around staff's calculated projection.

Line No.	Source		Excludes Overtime: Officers	Exempt	Non Exempt	Union	Total
1	Avista Data	Annualized Payroll-2013	**$296,984**	**$3,206,598**	**$1,091,376**	**$2,611,743**	7,206,701
2	Avista Data	Ave. # of Employees (FTE)-2013	1	30	18	31	80
3	(1)/(2)	Average Salary	$296,984	$106,887	$60,632	$84,250	$90,084
4	CPI Index - See Below	Allowable % Increase	1.03812	1.03812	1.03812	1.08477	0.0
5	Avista Data	Ave. # of Employees (FTE)-2016	1	30	19	30	80
6	(3)*(4)*(5)	Projected Payroll	$308,304	$3,328,818	$1,195,917	$2,741,750	$7,574,789
7	Avista Data	Annualized Payroll-2016	$315,838	$3,590,448	$1,286,600	$2,782,694	$7,975,580
8	(6)-(7)	Total Difference	$7,534	$261,630	$90,683	$40,944	$400,791
9	(6)*.10	10% Band - Allowable	$30,830	$332,882	$119,592	$274,175	$757,479
10	[(8) or (9)] * .5	50% Sharing of Lesser of Difference or Band	$3,767	$130,815	$45,341	$20,472	$200,395
11	(6)+/-(10)	Staff Proposed Level	$312,071	$3,459,633	$1,241,259	$2,762,222	$7,775,185
12	(11)-(7)	Net Payroll Adjustment	($3,767)	($130,815)	($45,341)	($20,472)	($200,395)
13	Avista Data	O&M Expense as % of Payroll Exp.	100.0%	77.5%	95.1%	87.8%	0.0%
14	(12)*(13)	O&M Expense Adjustment - Systemwide	($3,767)	($101,381)	($43,120)	($17,974)	$0
15	SO	Oregon Allocation Factor	1	1	1	1	0
16	(14)*(15)	**O&M Expense Adjustment**	**($3,767)**	**($101,381)**	**($43,120)**	**($17,974) (1)**	**($105,149)**
17	Avista Data	Capitalized Labor % of Payroll Exp.	0.00%	22.50%	4.90%	12.20%	0.00%
18	(12)*(17)	Rate Base Adjustment - Systemwide	$0	($29,433)		(1)	$0
19	(18)*(15)	**Rate Base Adjustment - Oregon**	**$0**	**($29,433)**	**$0**	**$0**	**($29,433)**

	Annual CPI	Union Increases - Actual
2013	1.5000	3.0000
2014	1.6000	3.0000
2015	0.6667	2.2500
	1.03812	1.0848

Officers	$0
Exempt	($101,381)
Non Exempt	($43,120)
Admin	($144,501)

The Company used the method provided by Commission Staff to compute this adjustment. The method uses total Company data and allocates a portion to Oregon. Due to this, detailed data is not available for administrative vs. O&M. Therefore, the Company will allocate officers, exempt and non-exempt to administrative and union to O&M.

(1) The Company feels that all employee classes (officers, exempt, non-exempt, union) should be included in this calculation, whether it is an increase to expense or a decrease to expense, because it is the net that should also be considered. However, for purposes of this earnings test, the Company has removed any resulting increases to expense. It should be noted, the Company does not agree with removing this increase to expense and reserves the right to include all components in future rate case proceedings.

Prep by: ____________ 1st Review: __________

Date: 10/7/2015 Mgr. Review: __________

Avista Utilities

Adjust 2014 Short Term Incentives
Adjusts Incentives to 6-Year Average

	Non-Executive Adjust 6-Year Average		Executive Adjust 6-Year Average		Total Adjustment		
Results of Operations (System)	$	12,627,683	$	3,675,748	$	16,303,431	
O & M Percentage		59%		33%			
Total O & M s	**$**	**7,440,231**	**$**	**1,223,657**	**$**	**8,663,888**	
Projected O & M Payout	$	9,821,971	$	2,268,980	$	12,090,951	
O & M Percentage		60%		33%			
Total O & M s	**$**	**5,893,183**	**$**	**748,763**	**$**	**6,641,946**	
Projected Payout (System 6 Year Average)		102.16%		40.23%			OR Alloc
6 Year Average Amount	**$**	**6,020,279**	**$**	**301,252**	**$**	**6,321,531**	$ 550,099.66
Total Adjustment		**(1,419,952)**		**(922,405)**		**(2,342,357)**	
Allocated toWashington **Electric**							
0.71547 Note 7							
0.67900 Note 4	$	(689,819)	$	(448,108)	$	(1,137,927)	
Allocated to Washington **Gas**							
0.19751 Note 7							
0.70758 Note 4	$	(198,444)	$	(128,910)	$	(327,354)	
Allocated to Idaho Electric							
0.71547 Note 7							
0.32100 Note 4	$	(326,115)	$	(211,845)	$	(537,960)	
Allocated to Idaho Gas							
0.19751 Note 7							
0.29242 Note 4	$	(82,011)	$	(53,274)	$	(135,285)	
Allocated to Oregon							
0.08702 Note 7	$	(123,564)	$	(80,268)	$	(203,832)	

Source: G-ALL-12A
Source: E-ALL-12A

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/20/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Bahr	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 224	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

With regard to Workpaper Smith 2.12, what is the amount of capitalized incentive compensation included in the Company's proposed 2016 test year revenue requirement (system and Oregon allocated)?

RESPONSE:

The amount of Oregon capitalized incentive compensation included in the Company's proposed 2016 test year is approximately $556,000. Staff_DR_224 Attachment A includes system level capital incentive.

Please note the calculation for the above estimate includes a calculation for 2013 and 2014 and is based on actual incentives capitalized and actual capital spend.

The calculation for 2015 and 2016 is based on an estimate of the actual amount capitalized in 2013 and 2014 compared to actual spend. This percentage was applied to pro-formed plant additions in the Company's Case.

Please see Staff_DR_224 Attachment A for the system detail as well as calculation support.

Avista Utilities UG 288
Test Year Ended 12/31/2016
000's

S-X Wages and Salary

Staff's adjustment is based on a series of adjustments in multiple accounts related to compensation. Wages & Salaries are adjusted using the Commission's 3-year wage and salary model. Overtime is adjusted using the same approach as is used in Staff's 3-year Wage and Salary Model. In this case, Staff does not propose an adjustment to the Company's FTE levels, which have remained relatively constant over the past 3 years. Finally, Payroll taxes and O&M depreciation expense are adjusted to reflect Staff's adjustments.

	OR-Allocated			
Description/ Account No.	**Company Filing**	**Staff (O&M only)**	**O&M Adjustment**	**Capital Adjustment**
Wages & Salaries	$ 7,976	$ 7,920	$ (56)	$ (4)
FTE Adjustment	$ 7,781	$ 7,781	$ -	$ -
Overtime	$ 444	$ 444	$ (0)	$ (0)
Bonus & Incentives	$ 550	$ 262	$ (288)	$ -
Bonus & Incentives	$ 556	$ 556	$ -	$ (278)
Total OR - Allocated Adjustments			**$ (344)**	**$ (282)**

	Oregon-Allocated			
Payroll Taxes	$ 695	$679	$ (16)	**$ (16)**
Depreciation O&M Adjustment Associated with Capital Adjustment				**$ (0.2)**

Avista Utilities UG 288

Calculation of PUC 3-Year Wage Formula

Actual 12/31/2013 to Proforma 12/31/2016

Explanation: Staff's proposal adjusts Avista's test period base wages and salaries in accordance with guidelines followed in previous rate cases. Hence, Staff allows wages and salaries (excluding union wages) to increase based on published CPI projections, and then allows the Company to share 50/50 the lesser of the difference between the Company's & Staff's calculated projections, or a 10% band around Staff's calculated projection. Union wages are increased at the contracted amounts as the negotiations are considered to be conducted at "arms length."

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	WP 3.03 Restate Labor - wp 1	Actual Base Payroll (2013)	**$296,984**	**$3,206,598**	**$1,091,376**	**$2,611,743**	**$7,206,701**
2	WP 3.03 Restate Labor - wp 1	Ave. # of Employes (FTE) (2013)	1	30	18	31	80
3	(1)/(2)	Average Salary	$296,984	$106,887	$60,632	$84,250	
4	Actual/Forecast CPI Index*	Allowable % Increase	1.0364 [1]	1.0364 [1]	1.0364 [1]	1.0927 [2]	
5	WP 3.03 Restate Labor - wp 1	Ave. # of Employes (FTE) (2016)	1	30	19	30	80
6	(3)*(4)*(5)	Projected Payroll	**$307,781**	**$3,323,179**	**$1,193,891**	**$2,761,861**	**$7,586,712**
7	WP 3.03 Restate Labor - wp 1	Test Period Payroll	**$315,838**	**$3,590,448**	**$1,286,600**	**$2,782,694**	**$7,975,580**
8	(7)-(6)	Total Difference for Sharing	$8,057	$267,269	$92,709	$20,833	
9	(7)*.10	10% Band - Allowable	$30,778	$332,318	$119,389	$276,186	
10	[(8) or (9)] *0.5	50% Sharing of Lesser of Difference or Band	$4,028	$133,635	$46,354	$10,417	
11	(6)+(10)	Staff Proposed Level	**$311,810**	**$3,456,813**	**$1,240,246**	**$2,772,277**	**$7,781,146**
12	(11)-(7)	Net Payroll Adjustment	**($4,028)**	**($133,635)**	**($46,354)**	**($10,417)**	**($194,434)**
13	WP 3.03 Restate Labor - wp 1	O&M Expense as % of Payroll Exp	100.00%	77.50%	95.10%	87.80%	
14	(12)*(13)	O&M Expense Adjustment - Systemwide	($4,028)	($103,567)	($44,083)	($9,146)	($160,824)
15	WP 3.03 Restate Labor - wp 3)	Oregon Allocation Factor	1.0000	1.0000	1.0000	1.0000	1
16	(14)*(15)	**O&M Expense Adjustment -Oregon**	**($4,028)**	**($103,567)**	**($44,083)**	**($9,146)**	**($160,824)**
17	1 - (13)	Rate Base as % of Payroll Exp	0.00%	22.50%	4.90%	12.20%	0.00%
18	(12)*(17)	Rate Base Adjustment - Systemwide	$0	($30,068)	($2,271)	($1,271)	**($33,610)**
19	(18)*(15)	**Rate Base Adjustment - Oregon**	**$0**	**($30,068)**	**($2,271)**	**($1,271)**	**($33,610)**

[1]Source - OR Dept of Admin Srvcs, Office of Economic Analysis
Oregon Economic & Revenue Forecast Sept 2015, Volume XXXV, No. 3, page 47
Actual/Forecast All-Urban Consumer Price Index

2014	1.6%
2015	0.2%
2016	1.8%
	1.0364

[2] Union Factor Source: Andrews WP 3.03 Restate Labor WP 1)

Union Increase 2014	3.00%
2015	3.00%
2016	3.00%
	1.0927

Avista Utilities UG 288

Wage & Salary Adjustment Based on Staff's FTE Adjustment

Actual 12/31/2013 to Proforma 12/31/2016

Explanation: Though the Company's system FTE increased from 1520 to 1548 from 2013-2014, the Company's Oregon-allocated FTE remained constant at 80. The Company proposes the 2014 FTE amount of 80. Staff finds the Oregon allocated FTE amount reasonable and proposes no adjustment.

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	WP 3.03 Restate Labor - wp 1	Test Period Base Wages & Salaries	$315,838	$3,590,448	$1,286,600	$2,782,694	**$7,975,580**
2	PUC 3-year W&S Adj, line 16	Staff Adj to Test Period Payroll	($4,028)	($133,635)	($46,354)	($10,417)	**($194,434)**
3	(1)-(2)	Adjusted Payroll	$311,810	$3,456,813	$1,240,246	$2,772,277	**$7,781,146**
4	WP 3.03 Restate Labor - wp 1	Ave. # of Employes (FTE) (2016)	1	30	19	30	80
5	(3)/(5)	Adjusted Average Salary	311,810	115,227	65,276	92,409	
6	See Explanation above	Staff Proposed FTE	1	30	19	30	80
7	(5)*(6)	Staff Proposed Proforma Payroll	**$311,810**	**$3,456,813**	**$1,240,246**	**$2,772,277**	**$7,781,146**
8	(3)-(7)	**Net Payroll Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**
9	PUC 3-year W&S Adj, line 13	O&M Expense as % of Payroll Expense	100.00%	77.50%	95.10%	87.80%	
10	(8)*(9)	O&M Expense Adjustment - Systemwide	$0.00	$0.00	$0.00	$0.00	
11	PUC 3-year W&S Adj, line 15	Oregon Allocation Factor	1	1	1	1	
12	(10)*(11)	**O&M Adjustment - Oregon**	$0.00	$0.00	$0.00	$0.00	**$0**
13	PUC 3-year W&S Adj, line 17	Capitalized Labor as % of Payroll Expense	0.00%	22.50%	4.90%	12.20%	
14	(8)*(13)	Rate Base Adjustment - Systemwide	$0.00	$0.00	$0.00	$0.00	
15	(14)*(11)	**Rate Base Adjustment - Oregon**	$0.00	$0.00	$0.00	$0.00	**$0**

Avista Utilities UG 288
Calculation of PUC 3-Year Overtime Formula
Actual 12/31/2013 to Proforma 12/31/2016

Explanation: Staff's proposal adjusts Avista's test period overtime in accordance with guidelines followed in previous rate cases. Officers and Exempt FTE are not eligible for overtime so overtime is removed from the test period. Staff allows overtime to increase based on published CPI projections, and then allows the Company to share 50/50 the lesser of the difference between the Company's & Staff's calculated projections, or a 10% band around Staff's calculated projection.

Line No.	Source		Officers	Exempt	Non Exempt	Union	Total
1	WP 3.03 Restate Labor - wp 3)	Actual Overtime (2013)	**$0**	**$179**	**$49,746**	**$394,636**	**$444,561**
2	WP 3.03 Restate Labor - wp 1	Average No. of FTE (2013)	1	30	19	30	**80**
3	(1)/(2)	Average Overtime per FTE	$0	$6	$2,618	$13,155	
4	PUC 3-year W&S Adj, line 4	Allowable % Increase	1.0364	1.0364	1.0364	1.0927	
5	S-2.2 FTE line 6	Staff Proposed Level FTE for Test Period	1	30	19	30	**80**
6	(3)*(4)*(5)	Projected Overtime	**$0**	**$187**	**$51,554**	**$431,228**	
7	WP 3.03 Restate Labor - wp 2)	Test Period Overtime	**$0** [1]	**$423** [1]	**$45,757** [1]	**$397,840** [1]	**$444,023**
10	(7)-(6)	Total Difference	$0	$237	$0	$0	
11	(9)*.10	10% Band - Allowable	$0	$19	$0	$0	
12	[(10) or (11)] *0.5	50% Sharing of Lesser of Difference or Band	$0	$9	$0	$0	
13	(6)+/-(10)	Staff Proposed Level	**$0**	**$196**	**$45,757**	**$397,840**	**$443,793**
14	(11)-(7)	Net Payroll Adjustment	**$0**	**($227)**	**$0**	**$0**	**($230)**
15	WP 3.03 Restate Labor - wp 1	O&M Expense as % of Payroll Exp	100.00%	77.50%	95.10%	87.80%	
16	(12)*(13)	O&M Expense Adjustment - Systemwide	$0	($176)	$0	$0	($176)
17	WP 3.03 Restate Labor - wp 2)	Oregon Allocation Factor	1	1	1	1	1
18	(14)*(15)	**O&M Expense Adjustment - Oregon**	**$0**	**($176)**	**$0**	**$0**	**($176)**
19	1 - (15)	Rate Base as % of Payroll Exp	0.000%	22.500%	4.900%	12.200%	
20	(14)*(19)	Rate Base Adjustment - Systemwide	$0	($51)	$0	$0	($51)
21	(20)*(17)	**Rate Base Adjustment - Oregon**	**$0**	**($51)**	**$0**	**$0**	**($51)**

[1] Per WP 3.03 2) 2014 YE OR Labor Detail - For 3YR CPI Analysis

	Officers	Exempt	Non-Exempt	Union
2014 OT Dollars	$0	$399	$43,125	$374,943
Increase - 2014		0.49%	0.49%	0.71%
Increase - 2015		3.00%	3.00%	3.00%
Increase - 2016		2.51%	2.51%	2.29%
2016 Test Year OT Dollars	$0	$423	$45,757	$397,840

Avista Utilities UG 288
Payroll Taxes
Test Year Ended December 31, 2016

		OR-Alloc
UG 288 Test Period Wages & Salaries and Overtime	$	8,419,603
UG 288 Payroll Tax as percentage of labor (per Staff Data Request No. 217)		8.25%
	$	694,617
Staff-Adjusted Wages & Salaries and Overtime	$	8,224,939
Payroll Taxes factor from above		8.25%
Staff Adjusted Payroll Taxes	$	678,557
Avista UG 288 Payroll Taxes	$	694,617
Staff Adjusted Payroll Taxes	$	678,557
Adjustment	**$**	**(16,060)**

Avista Utilities UG 288
Depreciation
Test Year Ended December 31, 2016

	W&S		FTE		Overtime		**Total**	
	Co-wide	OR-Alloc	Co-wide	OR-Alloc	Co-wide	OR-Alloc	Co-wide	OR-Alloc
O&M	($160,824)	(160,824)	$0	$0	($176)	($176)	($161,000)	(161,000)
Rate Base	($33,610)	(33,610)	$0	$0	($51)	($51)	($33,661)	(33,661)
							($194,661)	**(194,661)**

O&M Depreciation associated with Capital Adjustments **$ (172)**

[1] Test Year Gross Plant	$	368,415,000
[2] Annual Test Year Depreciation	$	1,880,000
% Avg. Depreciation to RB		0.5103%

[1]See Avista/502, Smith/4 at 219
[2]See Avista/502, Smith/3 at 131

Avista Utilities UG 288
Incentives
Test Year Ending December 31, 2016

Explanation: Bonuses and incentives for Officers are not allowed per Commission policy (Order No. 99-033 at 62; Order No. 97-171 at 74-76). Non-Officer bonuses are disallowed at 50 percent (Order No. 99-697 at 44-45; Order No. 99-033 at 62).

No.	Source		Officers	Exempt	Non Exempt	Union	Other*	Total
1	Note ****	Test Period O&M Incentives**	$ 26,215	$ 405,400	$ 77,219	$ 41,265	$ -	$ 550,100
2	See Explanation	Disallowance	100%	50%	50%	50%		
3	(1) * (2)	Staff Adjustment to Test Period Incentives	$ 26,215	$ 202,700	$ 38,610	$ 20,633		
4	(1) - (3)	Adjusted Incentives	$ -	$ 202,700	$ 38,610	$ 20,633	$ -	
5	S-2.2 FTE	Average # of Employees (FTE)	1	30	19	30		
6	(4) / (5)	Adjusted Average Incentives	$ -	$ 6,757	$ 2,032	$ 688		
7	S-2.2 FTE	Staff Proposed FTE	1	30	19	30		
8	(6) * (7)	Staff Proposed Incentives	$ -	$ 202,700	$ 38,610	$ 20,633		$ 261,942
9	(8) - (1)	**Net O&M Incentive Adjustment**	$ (26,215)	$ (202,700)	$ (38,610)	$ (20,633)	$ -	$ (288,157)
10	Note ***	Test Period Capitalized Incentives		$ 430,252	$ 81,953	$ 43,795		$ 556,000
11	See Explanation	Disallowance	100%	50%	50%	50%		
12	(10) * (11)	Staff Adjustment to Test Period Incentives	$ -	$ 215,126	$ 40,976	$ 21,897		
13	(10) - (12)	Adjusted Incentives	$ -	$ 215,126	$ 40,976	$ 21,897		
	S-2.2 FTE	Average # of Employees (FTE)	1	30	19	30		
	(4) / (5)	Adjusted Average Incentives	$ -	$ 7,171	$ 2,157	$ 730		
14	S-2.2 FTE	Staff Proposed FTE	1	30	19	30		
15	(6) * (7)	Staff Proposed Incentives	$ -	$ 215,126	$ 40,976	$ 21,897		$ 278,000
16	(8) - (1)	**Net Capital Incentive Adjustment**	$ -	$ (215,126)	$ (40,976)	$ (21,897)		$ (278,000)

* Other is usually comprised primarily of payroll taxes; however, per conversation with the Company, payroll taxes are included in WP 2.12 Incentive Adjustment

** These amounts include O&M incentives only (per conversation with Company regarding DR 224 and WP 2.12 Incentive Adjustment)

*** Capitalized incentives obtained from DR 224 and allocated amongst labor groups by Staff using O&M amounts on line 1

$ 556,000	Capitalized TY OR incentives per DR 224	
	O&M % (see Note ****)	Capitalized OR TY Incentives
Exempt	77.38%	$ 430,252
Non-Exempt	14.74%	$ 81,953
Union	7.88%	$ 43,795

**** These amounts calculated by Staff as follows:

Executive	Non-executive	
$ 301,252	$ 6,020,279	from WP 2.12 Incentive Adjustment
8.702%	8.702%	allocation % per WP 2.12 Incentive Adjustment
$ 26,215	$ 523,885	TY incentives allocated to Oregon

Employee Category	2015	per DR 218	% calc by Staff	Non-exec OR TY O&M Incentives
Exempt	$ 8,758,028		77.38%	$ 405,400
Non-Exempt	$ 1,668,196		14.74%	$ 77,219
Union	$ 891,467		7.88%	$ 41,265
	$ 11,317,691	Total Non-executive		

CASE: UG 288
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Confidential Exhibits in Support
Of Opening Testimony

October 16, 2015

STAFF EXHIBIT 803

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

CASE: UG 288
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Other Revenue, Load Forecasting

Opening Testimony

October 16, 2015

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

A. My name is Max St. Brown. I am a Utility Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High St. SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/901.

Q. Did you include any other exhibits for this testimony?

A. Yes. Exhibit Staff/902 contains 16 pages, of which Staff prepared pages 14-15.

- Page 1: The Company's supplemental response to Staff DR 193 providing a description of the Company's June 2015 forecasts.
- Page 2: Attachment A of the Company's response to Staff DR 187 providing the composition of Other Revenue.
- Pages 3-13: Attachment A of the Company's response to Staff DR 194 providing the Company's June 2015 load forecasting models.
- Pages 14-15: Staff's commercial and industrial load forecasting models.
- Pages 16-17: An example of using housing starts as a leading indicator in regression models.

Q. What is the purpose of your testimony?

A. Staff reviews of Avista's Other Revenue and Avista's commercial and industrial load forecasts.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Has Avista made any adjustments to the load forecasting in its filed testimony?

A. Yes, in June 2015 the Company produced a second round of forecasts using updated data. Staff refers to this as the Company's June 2015 forecasts (the Company's filed testimony uses forecasts from 2014). In many cases, the June 2015 forecasts were performed using model specifications different from those in the filed testimony, in order to better fit the updated data.

Q. Did the Company have adjustments to its filed testimony due to the June 2015 forecasts?

A. Yes. In supplemental response to Staff DR 193, the Company stated, "The net effect of this adjustment is a revenue requirement <u>increase of $849,000 from the Company's original filing</u>." This supplemental response is attached as Exhibit Staff/902, St. Brown/1.

Q. Does Staff use the updated data?

A. Yes, Staff uses the most recent data. The Company also used the most recent data in its June 2015 forecasts, but not in its filed testimony. The Company provided this data to Staff in response to Staff DR 193.

Q. Please summarize your recommendations.

A. Table 1 below provides a summary of Staff's adjustment related to Other Revenue.

Table 1			
Description	Company Filing – OR Allocated	Staff – OR Allocated	Adjustment
Other Revenue (000's of Dollars)	$167[1]	$202	$36

In regards to load forecasting, the testimony of Staff witness Bhattacharya in Exhibit Staff/1000 presents revenue requirement adjustments. For comparison purposes, Table 2 provides Staff's commercial and industrial load forecasts compared to the Company's June 2015 load forecasts.

Table 2			
Description	Company – June 2015 load forecasts (provided in response to Staff DR 193; differs from forecasts in filed testimony)	Staff – load forecasts	Adjustment
Sch. 420, Commercial and Industrial 2016 Normalized usage (in therms)	26,349,771 therms[2]	26,447,572 therms	97,801 therms
Large Sales Schs. 424, 440, & 444 2016 Normalized usage (in therms)	8,042,146 therms[3]	8,138,692 therms	96,546 therms
Transport Schs. 447 & 456 2016 Normalized usage (in therms)	44,926,584 therms[4]	45,073,772 therms	147,188 therms

[1] *See*: line 4 of Avista/501, Smith/1.
[2] *See*: Cells KA52:KA63 and KI52:KI63 in the "OR June 2015 Forecasts" tab of the file *Staff_DR_193 Attachment A - Gas Data and Forecasts June 2015.xlsx* submitted in response to Staff DR 193.
[3] *See*: id Cells KB52:KD63 and KJ52:KL63.
[4] *id*, Cells KE52:KE63 and KM52:KN63.

First, Staff recommends that Avista's test year Other Revenue be adjusted upwards by $35,995. The driver of this result is the growth in miscellaneous service revenue from 2010-2014. Second, Staff recommends that Avista's commercial and industrial load forecasts be updated to address three issues identified by Staff: including a timber industry variable, avoiding subsetting the data, and including January 2004 through December 2004 data. Addressing these issues is relevant for both the Company's filed testimony and the Company's June 2015 forecasts. As described in the testimony of Staff witness Bhattacharya in Exhibit Staff/1000, Staff's resolution of these issues, and the issues in the residential load forecasts, results in Staff recommending that Avista's test year revenue be adjusted downwards by approximately $867,796 compared to the Company's filed testimony.

ISSUE 1, OTHER REVENUE

Q. Please summarize what Avista includes in revenue requirement for Other Revenue.

A. The Company's test year adjusted total for Other Revenue is $166,455. This is comprised of: sales for resale, miscellaneous service revenue, other gas revenue-gas property rent, other gas revenue – misc, and other gas revenue-DSM lost margin.[5] The value of other gas revenue – misc is zero for the test year.

Q. How does the Company account for sales for resale?

A. In response to Staff DR 169, the Company stated "Sales for Resale is a purchased gas cost related account, there is no net income impact associated with consolidating the gas costs."

Q. How does the Company compute test year Other Revenue?

A. The Company uses its 2014 value as its test year value because the 2014 value in the Company's response to Staff DR 187 (attached as Staff/902, St. Brown/2) matches the 2016 value on line 4 of Avista/501, Smith/1. As described in Staff's previous answer, sales for resale revenue is subtracted from Other Revenue so as not to have a net income impact; additionally, "other gas revenue, DSM lost margin" is also subtracted from Other Revenue.

Q. Excluding sales for resale and other gas revenue-DSM lost margin, what is the largest component of Other Revenue?

[5] See: Company's response to Staff DR 187. This is attached as Staff/902, St. Brown/2.

A. The next largest element of Other Revenue is “Miscellaneous service revenue,” which in 2014 represented 99.5 percent of Other Revenue, excluding sales for resale and other gas revenue-DSM lost margin.

Q. Please describe miscellaneous service revenue.

A. Miscellaneous service revenues are revenues from the Miscellaneous Charges listed in Rule No. 20 in the Company’s tariff. Examples include reconnect charges, late payment fees, and returned check bank charges. These charges correlate positively with the number of customers.

Q. Does Staff forecast an increase in the number of customers between 2014 and 2016?

A. Yes, the testimony of Staff witness Bhattacharya forecasts a 1,488 increase in the monthly average number of customers between 2014 and 2016. The monthly average number of residential customers was 85,789 in 2014 and 87,277 in 2016, as forecasted by Staff witness Bhattacharya in Exhibit Staff/1000. This is a 0.86 percent yearly increase in the average number of residential customers from 2014 to 2016.

Q. What impact does this have on miscellaneous service revenue?

A. Because, miscellaneous service charges correlate positively with the number of customers, Staff forecasts that miscellaneous service revenue increases from 2014 to 2016.

Q. How did Staff forecast 2016 miscellaneous service revenue?

A. Staff ran a regression with change in number of customers as the explanatory variable and with change in miscellaneous service revenues as the variable to be explained. This regression indicated that in the data from 2010 to 2014, a one customer increase in the number of customers is associated with a $24.19 increase in the total miscellaneous service revenue. Notice this association cannot be interpreted as the average miscellaneous service charges per customer. This finding is applied to forecast miscellaneous service revenue in 2016. As described above, Staff forecasts a 1,488 increase in the monthly average number of customers between 2014 and 2016. Multiplying this increase in customers by the $24.19 impact per customer results in a $35,995 forecasted increase in miscellaneous service revenue.

Q. Has Staff reviewed "other gas revenue-gas property rent"?

A. Yes, Staff has reviewed the "Other Gas Revenue-Gas Property Rent" and has no adjustments.

Q. What is Staff's conclusion regarding test year Other Revenue?

A. Staff forecasts Other Revenue at $201,693; this is the sum of miscellaneous service revenue and "other gas revenue–gas property rent." This is a $35,995 upwards adjustment to the Company's filed value.

ISSUE 2, COMMERCIAL AND INDUSTRIAL LOAD FORECASTING

Q. Please summarize the Company's load forecast for commercial and industrial customers.

A. Table No. 1 at lines 4-10 of Avista/700, Forsyth/5 indicates that there are seven Schedules in Oregon. Schedules 420, 424, 440, 444, and 447 serve commercial customers. Schedules 420, 424, 440, 444, 447, and 456 serve industrial customers. Within each of these Schedule and customer type combinations, the Company prepares its forecasts by region in order to capture regional weather patterns. These regions are Medford, Roseburg, Klamath Falls, and La Grande. The two components of load are forecasted separately: use-per-customer and number of customers – where these components can be multiplied to obtain the load. Thus, there are four subgroupings for each forecast: Schedule, customer type, region, and load component.

Avista/700, Forsyth/4 at lines 14-16 describes that the Company forecasted each subgrouping using models that "range from linear regression models to simple smoothing (averaging) models, depending on … the complexity of past customer growth." DR 194 Attachment A indicates that in the Company's June 2015 forecasts the Company forecasted 64 commercial and industrial subgroupings and used regression models for 36 of these subgroupings.

Q. What is the timing of the Company's forecasts?

A. Company witness Forsyth provided forecasts using data up to 2014 in Exhibit Avista/700 of the Company's filed testimony. In data responses, the Company provided a second round of forecasts computed in June 2015 using data up to

April 2015. The Company provided its June 2015 forecasting models in response to Staff DR 194; these are attached as Staff/902, St. Brown/3-13. The Company forecasts the test year January 2016 – December 2016. Thus, the June 2015 forecasts are for nine months to 20 months into the future.

Q. Please summarize Staff's recommendations for the commercial and industrial load forecasts.

A. Staff divides its recommendations based on the forecasting method used. For the simple smoothing (averaging) models, Staff recommends no change at this time. For the regression models, Staff makes three recommendations:

1. A variable related to the timber industry should be added to the use-per-customer regressions of timber industry customers.
2. Data time periods after 2004 should not be excluded from the regressions without a well-founded justification.
3. January 2004 – December 2004 data should not be excluded from the regressions because all data contains information and all information should be taken into account.

Staff applies adjustments based on these three recommendations to the Company's load forecasts, resulting in a 0.03 percent higher, than the Company's June 2015 forecasts, test year load for the commercial and industrial portion of the load forecasts. Staff's commercial and industrial load forecasts are below those found in the testimony of Company witness Forsyth in Exhibit Avista/700 of the Company's filed testimony, but are above the Company's June 2015 forecasts attached as Staff/902, St. Brown/3-13.

Staff's regression models are presented in Exhibit Staff/902, St. Brown/14-15. Staff used the output of these regression models to compute adjustments to Schedule 420, 424, 440, 444, 447, and 456 loads. Then these adjusted loads were plugged into the revenue model Excel spreadsheet provided by the Company in response to Staff's DR 300, which asked for a description of how Company witness "Forsyth's [Avista/700] models were incorporated in the revenue model." The results of the revenue model were plugged into the "Usage & Billings by Rate Schedule" portion of the workpaper supporting Avista/900 of Company witness Ehrbar. As described in the testimony of Staff witness Bhattacharya, Staff's addressing of the commercial and industrial load forecasting issues and the residential load forecasting issues results in Staff recommending that Avista's test year revenue be adjusted downwards by approximately $867,796 from the Company's filed testimony.

Q. What was the Company's approach in the simple smoothing (averaging) models?

A. For the subgroupings that the Company identified as having non-complex past growth patterns, the Company primarily used a 12-month moving average model to forecast their future values. In this method, the May 2015 forecast is the average of the last 12 months' values. Likewise, the June 2015 forecast is the average of the last 11 months in data and the May 2015 forecast.

Q. Does Staff find this approach reasonable?

A. At this time, yes. Using simple smoothing (averaging) models is reasonable when explanatory data are not available. For example, the Company's response to Staff DR 275 states, “much of the non-weather, non-seasonal volatility of the large customer cannot be modeled because it represents largely randomized operating events—for example, equipment failures and maintenance.”

Q. What is Staff’s recommendation regarding the simple smoothing (averaging) models?

A. At this time, Staff recommends no change and supports the simple smoothing (averaging) models for each of the subgroupings that the Company identified as having non-complex past growth patterns. However, Staff notes that it is important to regularly monitor trends that may affect the series being forecasted. To this end, Staff is supportive of the Company’s response to Staff DR 274 which states, “Avista, through its business managers and account executives, regularly communicate with its large commercial and industrial customers. … we believe we know well in advance if a customer was going to materially increase or decrease its usage, or discontinue service.” Staff requests that this information be communicated with Staff as well for purposes of verifying the forecasting models.

Q. What was the Company’s approach in the regression models?

A. The Company uses “Autoregressive integrated moving average” (ARIMA) models. Explanatory variables used to predict future therm usage in the Company’s models include lagged (past) values of the usage itself and an industrial production index (IPBASE). The regression models also control for seasonality and outliers. Explanatory variables used to predict future customers in the Company's commercial models include the number of residential customers. A defining characteristic of the ARIMA models is that they use past observations of the dependent variable itself as explanatory variables.

Q. Staff's first recommendation is that a variable related to the timber industry should be added to the use-per-customer regressions of timber industry customers. How does Staff support this recommendation?

A. The Company runs regressions for three special contract Schedule 447 customers. All three of these customers are involved in the timber industry. Staff communicated with the Oregon Department of Forestry and learned that many of the wood products in Oregon are used in housing. Thus, Staff added lagged West housing starts valuation as an explanatory variable to the Schedule 447, Klamath Falls, use-per-customer regression. This variable improved the forecast accuracy of the model as measured by in-sample "mean absolute percentage error" (MAPE), a measure of forecast accuracy. Further, this variable is statistically significant at a lower p-value than the IPBASE variable that the Company included. Thus, Staff supports adding a variable related to the timber industry because it adds explanatory power to the Schedule 447, Klamath Falls use-per-customer regression.

Q. How did Staff make adjustments based on Staff's first recommendation?

A. As discussed in the previous answer, Staff added lagged West housing starts valuation to the regression. These data are available from the U.S. Census and they represent the one year lagged value of new housing starts in the West [U.S.]. Staff uses the lagged version of the variable because housing starts are often recognized as a leading indicator. A leading indicator is a variable that is measured in the current time period, but whose value often correlates with changes to a future time period. In Staff's usage, 2015 West housing starts valuation data is used as a predictor of 2016 natural gas therm usage in the timber industry. The theory is: increasing economic activity in the housing industry necessitates increased production of timber products. Exhibit Staff/902, St. Brown/16-17 presents an example of housing starts as a leading indicator.[6] Using the number of housing starts provides similar results, but since higher value homes tend to be larger and use more timber products, Staff decided that "valuation of homes" had the strongest theoretical basis for necessitating increased production of timber products.

Q. What does Staff recommend for the Company's regression models?

A. The Company should add lagged West housing starts valuation or a similar variable to its Schedule 447 use-per-customer regressions.

A similar variable is volume of timber harvested in Oregon. Staff found that data on volume of timber harvested from the Oregon Department of Forestry is positively correlated with Schedule 447 use-per-customer. Specifically, volume

[6] Roubini, Nouriel, "Housing Starts/Building Permits," NYU Stern School of Business. Accessed September 29, 2015 from: http://pages.stern.nyu.edu/~nroubini/bci/housingstarts.htm

of timber harvest has a stronger correlation than IPBASE with Schedule 447 use-per-customer, as presented in the table below:

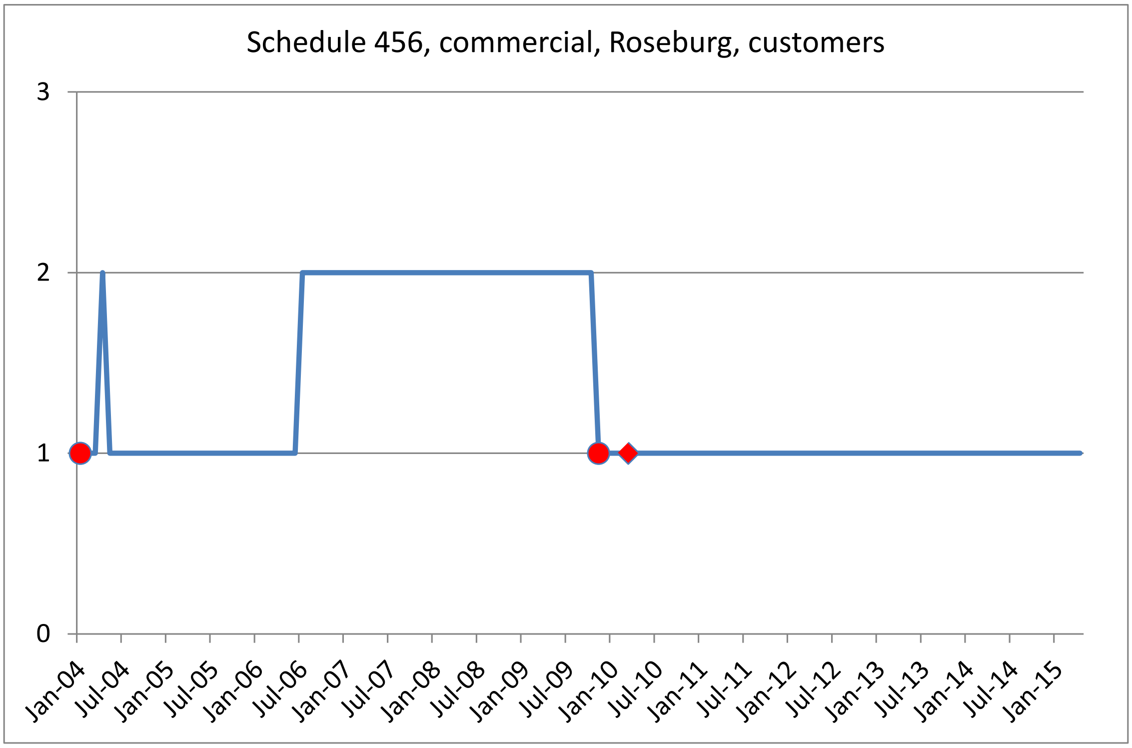
Correlation Coefficients for 2005-2014 data	
Oregon timber harvest and Schedule 447 therm usage:	IPBASE and Schedule 447 therm usage:
0.51	0.33

The Company uses IPBASE in its regressions. The Company could obtain forecasts of timber harvests from a paid subscription.

Q. Staff's second recommendation is that data time periods after 2004 should not be excluded from the regressions without a well-founded justification. How does Staff support and make recommendations based on this recommendation?

A. Staff adjusts the forecasting models of two subgroupings:

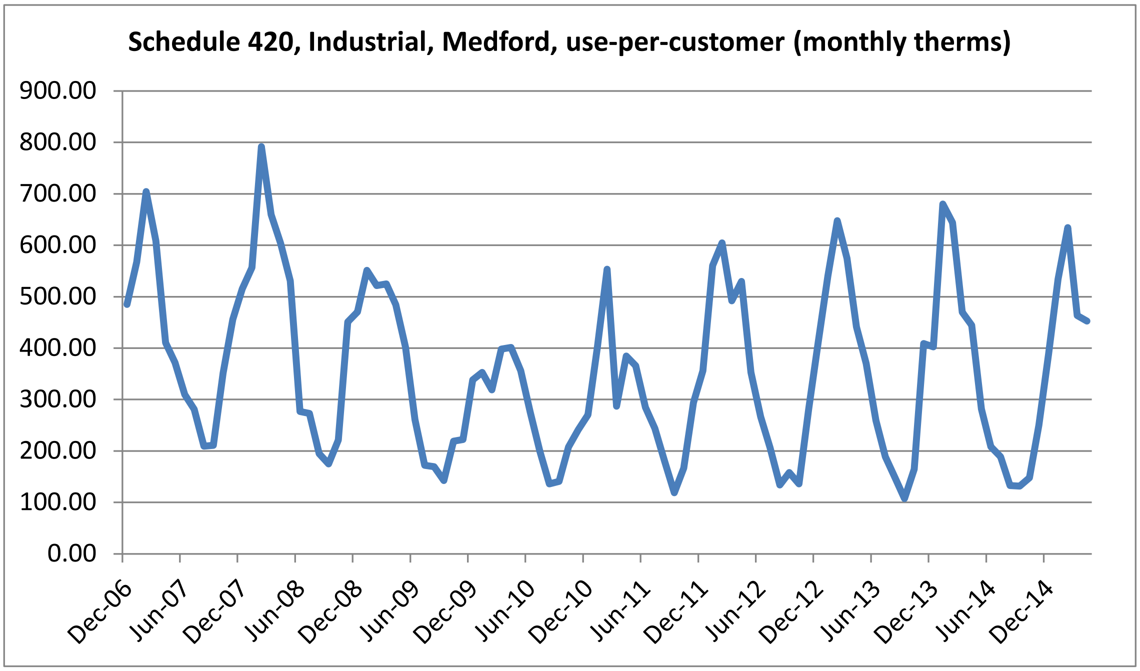
1. In regards to the Schedule 456, commercial, Roseburg, use-per-customer forecast, in response to Staff DR 194 the Company replied, "Model is restricted to March 2010 [onwards] because of a significant change in seasonality compared to earlier periods. This appears to reflect a downward-step in the number of customers in 2010." However, Staff determined that there were two customers in this subgrouping from July 2006 until October 2009 and then there was one customer from November 2009 onwards. This is shown in the graph below:



The figure demonstrates that the downward-step in the number of customers occurred in 2009, not 2010. In the figure, the diamond data point is where the Company began its dataset for the regression model of this use-per-customer subgrouping. Beginning the dataset at either circle is more appropriate. To be consistent with the Company's current approach, Staff begins the regression at the second circle in the figure above by adding data from November 2009 through February 2010.

2. With regard to the Schedule 420, industrial, Medford, use-per-customer forecast, the Company's response to Staff DR 194 states, "Model is restricted to 2008 [onwards] because schedule does not start until December 2006. In addition, seasonality changes significantly starting in 2008. Seasonality still

appears to be somewhat unstable." Staff graphed the use-per-customer in order to view the seasonality of the series. This graph is below:



From visually inspecting the graph above, Staff finds that seasonality is present from December 2006 onwards and thus does not support the Company's sub-setting of the data. Staff reran the model using the dataset beginning December 2006.

Q. What does Staff recommend for the Company's regression models?

A. Staff recommends that the Company include data from November 2009 through February 2010 in its forecast of Schedule 456, commercial, Roseburg, use-per-customer and should include data from December 2006 through December 2007 in its forecast of Schedule 420, industrial, Medford, use-per-customer.

Q. Staff's third recommendation is that the January 2004 – December 2004 data should not be excluded from the regressions because all

data contains information and all information should be taken into account. Has this issue been raised before?

A. Yes, this issue was discussed in Avista's last rate case, UG 284. Lines 23-30 of Joint Testimony Staff/102, Gardner and Muldoon/29 in the UG 284 rate case stated, "Based on the Company's response to Staff's Data Request 291 and conference calls, Staff understands that the explanation for selecting a subset of the sample is not based on any statistical tests, and thus is inconsistent with the standard econometric model building practices."

Q. How did Staff make adjustments based on Staff's third recommendation?

A. Staff reran the Company's regression models for each of the nine subgroupings using 2005 data not already facing an adjustment. Staff did not adjust the Schedule 420, commercial, Medford regressions which depend on the Schedule 410, residential regression, because that residential regression was not adjusted by Staff. Staff did not adjust the Schedule 444, industrial, La Grande, customer regression because the Company included ten dummy variables, indicating that there may be non-weather, non-seasonal volatility. With that as a starting point, Staff made two adjustments:

1. Staff incorporated Staff/1000, Staff witness Bhattacharya's Schedule 410, residential, customer forecasts for the Roseburg, La Grande and Klamath Falls regions.

2. Staff reran the Company's regression models after adding back in the January 2004 to December 2004 data. Staff used the Company's own

regression model specifications, but included the January 2004 to December 2004 data. This resulted in some load forecasts increasing and some load forecasts decreasing.

Q. Did Staff try any approaches that did not become recommendations?

A. Yes, Staff tried two theoretical approaches that did not fit the data well and thus did make not any recommendations related to these other approaches. First, Staff identified a theoretical relationship that population growth positively affects commercial customer growth. Thus Staff experimented with adding population as an explanatory variable in the commercial forecasts to replace the Company's residential customer variable. However, for this data set, using residential customers had more explanatory power, so Staff maintained the Company's approach in this respect. Second, Staff identified a theoretical relationship that economic activity positively affects commercial loads. Thus Staff experimented with adding Oregon total personal income from the Oregon Office of Economic Analysis. However this variable was not statistically significant in regressions, so Staff did not add this variable and maintained the Company's approach in this respect.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Max St. Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance & Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2013) Washington State University B.S., Economics (2009) Central Washington University

EXPERIENCE:

I have been employed by the Public Utility Commission since July 2015, with my current position being a Utility Economist, in the Utility Program's Energy – Rates, Finance and Audit Division. My current responsibilities include analysis and technical support for rate, finance, and audit related proceedings, with an emphasis on forecasting and marginal cost studies.

Prior to working for the OPUC I served as an Assistant Professor of Economics at Eckerd College in St. Petersburg, FL from 2013 to 2015. I have taught courses including Econometrics, Labor Economics, and Intermediate Microeconomics. As a graduate student at Washington State University I taught six course sections, including Econ of Renewable Energy.

My published research in peer-reviewed academic journals includes a study of the U.S. renewable energy industry and includes international economic impact studies.

I served as a summer fellow at the American Institute for Economic Research during summers 2011 and 2012.

CASE: UG 288
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

October 16, 2015

Exhibit 2

SUPPLEMENTAL RESPONSE:

(a): In the Company's response to Staff-193, base data for the most recent customer and use per customer (UPC) forecasts were provided. The Company is supplementing the response to Staff-193 in order to reflect the revised billing determinants from this most recent forecast in adjustment number 2.01 (2016 Test Year Revenue Adjustment). The effect of this revised adjustment is to increase Oregon net operating income by $3,608,000 ($4,099,000 in original filing) and a reduction to revenue requirement of $6,225,000 ($7,074,000 in original filing). The net effect of this adjustment is a revenue requirement increase of $849,000 from the Company's original filing. See the attachment labeled "Staff_DR_193 Supplemental Attachment A" for the workpapers supporting this revised adjustment.

During the analysis of the updated forecast data provided above, the Company discovered a formula error in its original filing which resulted in an incorrect assignment of usage to the individual rate blocks on Schedule 146. The resulting correction to the five usage blocks overstated revenue to Schedule 146 by $119,000 in the Company's original filing. The Company has corrected the assignment of usage to the individual rate blocks in the attachment labeled "Staff_DR_193 Supplemental Attachment A" discussed above.

Exhibit 2

	A	B	C	D	E	F	G	H	I
1	Avista Utilities								
2	Case No. UG 288								
3	Staff Data Request No. 187								
4									
5	Other Revenue Components 2010 through 2015								
6									
7	Part A. Actual Other Revenue by Category								
8									
9	FERC Accoun	Description		2010	2011	2012	2013	2014	YTD 06.2015
10									
11	483	Sales for Resale		60,527,185	76,479,320	67,211,233	90,624,357	115,399,902	39,737,199
12	488	Miscellaneous Service Revenue		138,727	140,056	140,853	151,862	165,698	31,476
13	493	Other Gas Revenue -Gas Property Rer		1,697	757	1,257	757	757	387
14	495	Other Gas Revenue - Misc		-	-	1,688	400	-	-
15	495600	Other Gas Revenue - DSM Lost Margir		45,425	48,905	36,414	173,046	28,157	2,111
16	**Actual Other Revenue**			**60,713,034**	**76,669,038**	**67,391,445**	**90,950,422**	**115,594,514**	**39,771,173**
17									
18	Part B. Hypothetical GRC Adjustments to Other Revenue								
19				2010	2011	2012	2013	2014	YTD 06.2015
20	Consolidate Sales for Resale with Gas Costs to Identify Net Gas Cost								
21	804	Purchased Gas Cost		116,944,219	137,348,913	119,814,355	138,793,793	161,753,493	59,222,060
22	805	PGA Deferral & Amortization		(351,216)	(1,812,369)	(388,538)	(385,337)	(5,302,882)	2,106,059
23	808	Nat Gas Storage Transactions		(658,386)	(20,098)	576,425	687,324	(1,666,445)	2,056,982
24	811	Gas Used for Product Extraction		(316,247)	(483,360)	(484,856)	(416,865)	(471,284)	(88,455)
25	483	Sales for Resale Revenue		(60,527,185)	(76,479,320)	(67,211,233)	(90,624,357)	(115,399,902)	(39,737,199)
26		Net Gas Cost		55,091,185	58,553,766	52,306,153	48,054,558	38,912,980	23,559,447
27									
28		Weather Adj Cost of Gas		658,529	(5,566,540)	(381,935)	(2,926,996)	5,218,230	
29		Normalized Cost of Gas		55,749,714	52,987,226	51,924,218	45,127,562	44,131,210	23,559,447
30									
31	Eliminate DSM Lost Margin to Reset Base for Future Lost Margin Calculations								
32	495600	Other Gas Revenue - DSM Lost Margir		(45,425)	(48,905)	(36,414)	(173,046)	(28,157)	(2,111)
33									
34	**Hypothetical Adjusted Other Revenue**			**140,424**	**140,813**	**143,798**	**153,019**	**166,455**	**31,863**

Exhibit 3

1. Medford, OR Forecasting Models

The forecasting models for the Medford region (Jackson County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

[7.51] $THM/C_{t,y,MED410.r} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \lambda RAP_{t,y-1,OR410} + \gamma_1 lnT + + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2006\uparrow =1} + \omega_{OL} D_{Dec\ 2005\ =1} + \omega_{OL} D_{May\ 2011\ =1} + \omega_{OL} D_{Jun\ 2011\ =1} + ARIMA\epsilon_{t,y}\ (11{,}0{,}0)(0{,}0{,}0)_{12}$

[7.51] Model notes:
1. SC dummy controls for a step-down in UPC for January 2006 ↑.
2. The variable lnT reflects a general control for multiple factors lowering UPC, including the impact of RAP.
3. AHS is not included because its impact is unstable and not statistically significant.

[7.52] $THM/C_{t,y,MED420.r} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \omega_{OL} D_{Dec\ 2009=1} + \omega_{OL} D_{Jan\ 2010\ =1} + \omega_{OL} D_{Feb\ 2010\ =1} + \omega_{OL} D_{Jan\ 2011\ =1} + ARIMA\epsilon_{t,y}\ (1{,}0{,}0)(0{,}0{,}0)_{12}$

[7.52] Model notes:
1. This schedule represents less than 10 customers.
2. January 2012 also appears to be an outlier, but controlling for it causes a convergence failure; however, it not controlling for it does not have a large impact of the forecasts.

Residential Sector, Customers:

[7.53] $C_{t,y,MED410.r} = \alpha_0 + \alpha_1 POP_{t,y,MED} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2008\uparrow =1} + \gamma_{RAMP} T_{Jan\ 2008} + \omega_{OL} D_{Feb\ 2015\ =1} + ARIMA\epsilon_{t,y}\ (7{,}1{,}0)(0{,}0{,}0)_{12}$

[7.53] Model notes:
1. SC dummy and ramping time trend control for a change in the time-path of customer growth staring in January 2008.

[7.54] $C_{t,y,MED420.r} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

Commercial Sector, THM:

[7.55] $THM/C_{t,y,MED420.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Nov\ 2008\uparrow =1} + \omega_{OL} D_{Jan\ 2005\ =1} + \omega_{OL} D_{Dec\ 2005\ =1} + \omega_{OL} D_{Dec\ 2006\ =1} + \omega_{OL} D_{Mar\ 2010\ =1} + \omega_{OL} D_{April\ 2010\ =1} + ARIMA\epsilon_{t,y}\ (11{,}0{,}0)(0{,}0{,}0)_{12}$

[7.55] Model notes:
1. SC dummy controls for a step-down in UPC for November 2008 ↑.
2. Work is ongoing to determine if RAP can be integrated into the model.

[7.56] $THM/C_{t,y,MED424.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2012\ =1} + \omega_{OL} D_{Jan\ 2013\ =1} + \epsilon_{t,y}\ for\ t,y\ July = 2010\ \uparrow$

[7.56] Model notes:
1. Model is restricted to July 2010 ↑ because of a significant change in UPC behavior compared to earlier periods .
2. Some non-stationarity at lag 3 in the ADF test; however this likely reflects the limited number of observations.

Exhibit 3

$$[7.57]\ THM_{t,y,MED444.c} = \beta_0 + \boldsymbol{\omega_{SD}D_{t,y}} + ARIMA\epsilon_{t,y}\,(1,0,0)(0,0,0)_{12}$$

$$[7.58]\ THM/C_{t,y,MED440.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \omega_{OL}D_{Sept\ 2008=1} + \omega_{OL}D_{Oct\ 2008=1} + \omega_{OL}D_{Nov\ 2008=1} + \omega_{OL}D_{Jan\ 2009=1} + \omega_{OL}D_{May\ 2009=1} + \omega_{OL}D_{Dec\ 2013=1} + ARIMA\epsilon_{t,y}\,(2,0,0)(0,0,0)_{12}\ for\ t,y = April\ 2007 \uparrow$$

[7.58] Model notes:
1. Model is restricted to April 2009 ↑ because schedule does not start until February 2007.

$$[7.59]\ THM/C_{t,y,MED456.c} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \boldsymbol{\omega_{SD}D_{t,y}} + \omega_{OL}D_{Sept\ 2009=1} + \omega_{OL}D_{Mar\ 2013=1} + \omega_{OL}D_{Dec\ 2013=1} + ARIMA\epsilon_{t,y}\,(12,0,0)(0,0,0)_{12}$$

[7.59] Model notes:
1. Transportation schedules are subject to structural change because of customers entering or exiting with enough loads to alter historical behavior.

Commercial Sector, Customers:

$$[7.60]\ C_{t,y,MED420.c} = \alpha_0 + \alpha_1 C_{t,y,MED410.r} + \boldsymbol{\omega_{SD}D_{t,y}} + \omega_{OL}D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\,(12,1,0)(0,0,0)_{12}$$

[7.60] Model notes:
1. $C_{t,y,MED410.r}$ are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2.

$$[7.61]\ C_{t,y,MED424.c} = C_{t,y-1} + 1\ (add\ approximately\ one\ customer\ per\ year)$$

[7.61] Model notes:
1. Due to the Compass software conversion, February 2015 is excluded from the historical data. The conversion resulted in a double counting of customers in February 2015. Therefore, including this month leads to a significant over-forecast of customers.

$$[7.62]\ C_{t,y,MED444.c} = 1\ if\ (THM/C_{t,y})_{MED,440.c} > 0$$

[7.62] Model notes:
1. There is typically only one customer served by this schedule. Therefore, the customer forecast is automatically set to one whenever the load forecast is greater than zero.

$$[7.63]\ C_{t,y,MED440.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$$

$$[7.64]\ C_{t,y,MED456.c} = C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$$

Industrial Sector, THM:

$$[7.65]\ THM/C_{t,y,MED420.i} = \alpha_0 + \alpha_1 HDD_{t,y}^{AVA} + \alpha_2 (HDD_{t,y}^{AVA})^2 + \alpha_3 QHDD_{t,y}^{AVA} + \alpha_4 (QHDD_{t,y}^{AVA})^2 + \delta_1 IP_{t,y} + \omega_{OL}D_{March\ 2011=1} + \boldsymbol{\omega_{SD}D_{t,y}} + ARIMA\epsilon_{t,y}\,(1,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$$

[7.65] Model notes:
1. Model is restricted to 2008 ↑ because schedule does not start until December 2006. In addition, seasonality changes significantly starting in 2008. Seasonality still appears to be somewhat unstable.
2. Work is ongoing to determine if RAP can be integrated into the model.

Exhibit 3

[7.66]
$THM/C_{t,y,MED424.i} = \alpha_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Aug\ 2012=1} + \omega_{OL} D_{Sept\ 2012=1} + ARIMA\epsilon_{t,y}\ (6,0,0)(0,0,0)_{12}\ for\ y = 2010 \uparrow$

[7.66] Model notes:
1. Model is restricted to 2010 ↑ because schedule does not start until January 2009. In addition, seasonality changes significantly starting in 2008. Seasonality still appears to be somewhat unstable.
2. There are typically only two customers in this schedule.

[7.67] $THM/C_{t,y,MED440.i} = \alpha_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{May\ 2013\uparrow=1} + ARIMA\epsilon_{t,y}\ (0,0,0)(1,0,0)_{12}\ for\ y = 2008 \uparrow$

[7.67] Model notes:
1. Model is restricted to 2008 ↑ because seasonality changes significantly starting in this period. Seasonality still appears to be somewhat unstable. The change in seasonality reflects a very large step-down in customers in 2007—falling from around 22 to five.
2. SC dummy controls for a step-up in UPC staring in May 2013.
3. Some non-white noise issues at lag 40 and beyond; likely reflects short time-series and its erratic behavior.

[7.68] $THM/C_{t,y,MED456.i} = \alpha_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Jan\ 2008=1} + \omega_{OL} D_{Sept\ 2008=1} +$
$ARIMA\epsilon_{t,y}\ (3,0,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

[7.68] Model notes:
1. Model is restricted to 2007 ↑ because of a modest change seasonality compared to earlier periods.
2. Work is ongoing for statistical controls so that 2005-2006 can be added to the estimation period.
3. Transportation schedules are subject to structural change because of customers entering or exiting with enough loads to alter historical behavior.

Industrial Sector, Customers:

[7.69] $C_{t,y,MED420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.70] $C_{t,y,MED424.i} = C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$

[7.71] $C_{t,y,MED440.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.72] $C_{t,y,MED456.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

2. Roseburg, OR Forecasting Models

The forecasting models for the Roseburg region (Douglas County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

[7.73] $THM/C_{t,y,ROS410.r} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \gamma_1 lnT + \lambda RAP_{t,y-1,OR410} +$
$\boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2006=1} + \omega_{OL} D_{Mar\ 2011=1} + \omega_{OL} D_{Dec\ 2011=1} + \omega_{OL} D_{Feb\ 2012=1} + ARIMA\epsilon_{t,y}\ (11,0,0)(0,0,0)_{12}$

[7.73] Model notes:
1. The variable lnT reflects a general control for multiple factors lowering UPC, including the impact of RAP.
2. AHS is not included because its impact is unstable and not statistically significant.

Exhibit 3

[7.74] $THM/C_{t,y,ROS420.r} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Jan\ 2013=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = March\ 2010 \uparrow$

[7.74] Model notes:
1. Model restricted to March 2010 ↑ because schedule does not start until October 2009.
2. This schedule appears to be dying out.

Residential Sector, Customers:

[7.75] $C_{t,y,ROS410.r} = \varphi_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2007\uparrow=1} + \gamma_{RAMP} T_{Jan\ 2007} + \omega_{OL} D_{Nov\ 2005=1} + \omega_{OL} D_{Dec\ 2005=1} + \omega_{OL} D_{Nov\ 2006=1} + \omega_{OL} D_{Mar\ 2007=1} + \omega_{OL} D_{Dec\ 2007=1} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\ (6,1,0)(0,0,0)_{12}$

[7.75] Model notes:
1. SC dummy and ramping time trend control for a change in the time-path of customer growth staring in January 2007.

[7.76] $C_{t,y,ROS420.r} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.75] Model notes:
1. Schedule appears to have died; no customers are currently being reported.

Commercial Sector, THM:

[7.77] $THM/C_{t,y,ROS420.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 2011=1} + ARIMA\epsilon_{t,y}\ (8,0,0)(0,0,0)_{12}$

[7.78] $THM/C_{t,y,ROS424.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Oct\ 2007=1} + \omega_{OL} D_{July\ 2009=1} + \omega_{OL} D_{Mar\ 2011=1} + \omega_{OL} D_{Feb\ 2013=1} + ARIMA\epsilon_{t,y}\ (9,0,0)(0,0,0)_{12}$

[7.79] $THM/C_{t,y,ROS440.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Dec\ 2010\uparrow=1} + \omega_{OL} D_{Oct\ 2009=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Nov\ 2010=1} + \omega_{OL} D_{May\ 2013=1} + \omega_{OL} D_{June\ 2013=1} + \omega_{OL} D_{Oct\ 2013=1} + \omega_{OL} D_{Jan\ 2015=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = April\ 2007 \uparrow$

[7.79] Model notes:
1. Model is restricted to April 2007 ↑ because schedule does not start until February 2007.
2. SC dummy controls for step-up in UPC starting in December 2010.

[7.80] $THM/C_{t,y,ROS456.c} = \varphi_0 + \varphi_1 HDD_{t,y}^{AVA} + \varphi_2 (HDD_{t,y}^{AVA})^2 + \varphi_3 QHDD_{t,y}^{AVA} + \varphi_4 (QHDD_{t,y}^{AVA})^2 + \omega_{OL} D_{July\ 2014=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = March\ 2010 \uparrow$

[7.80] Model notes:
1. Model is restricted to March 2010 ↑ because of a significant change in seasonality compared to earlier periods. This appears to reflect a downward-step in the number of customers in 2010.

Exhibit 3

Commercial Sector, Customers:

[7.81] $C_{t,y,ROS420.c} = \varphi_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_1 T + \omega_{OL} D_{Jan\ 2008\ =1} + \omega_{OL} D_{Mar\ 2009=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\ (6,1,0)(0,0,0)_{12}$

[7.81] Model notes:
1. Model does not use schedule 410 customers as driver. This reflects the lack of correlation between residential 410 and commercial 420 customer growth.
2. The lack of correlation noted in Point 1 could reflect Roseburg's position between larger cities that offer a range of commercial activities. Competition from these cities may be inhibiting commercial growth in Roseburg.

[7.82] $C_{t,y,ROS424.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.83] $C_{t,y,ROS440.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.84] $C_{t,y,ROS456.c} = C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$

Industrial Sector, THM:

[7.85] $THM/C_{t,y,ROS420.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (3,1,0)(0,0,0)_{12}\ for\ y = 2010 \uparrow$

[7.85] Model notes:
1. Model is restricted to 2010 ↑ since the schedule does not start until September 2009.

[7.86] $THM/C_{t,y,ROS424.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Aug\ 2007\ =1} + ARIMA\epsilon_{t,y}\ (5,0,0)(0,0,0)_{12}\ for\ y = 2007 \uparrow$

[7.86] Model notes:
1. Model is restricted to 2007 ↑ because of a significant change in seasonality in earlier periods.
2. Schedule has died. No customers or load reported in 2015

[7.87] $THM/C_{t,y,ROS440.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2012\ =1} + \omega_{OL} D_{Aug\ 2012\ =1} + \omega_{OL} D_{Jan\ 2014\ =1} + ARIMA\epsilon_{t,y}\ (4,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[7.87] Model notes:
1. Model is restricted to 2008 ↑ because of a significant step-down in UPC compared to earlier periods. This step-down reflects a large step-down in the number of customers from around 13 to 3 to 5.

[7.88] $THM_{t,y,ROS447m.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2008\ =1} + ARIMA\epsilon_{t,y}\ (4,1,0)(0,0,0)_{12}\ for\ t,y = July\ 2008 \uparrow$

[7.88] Model notes:
1. Model is restricted to July 2008 ↑ because from September 2005 to November 2007 load fell to zero. Starting in July 2008, load returned to more normal operating levels.
2. This is a special contract customer. In Oregon, special contract customers have a different regulatory status during rate case proceedings.

Exhibit 3

[7.89] $THM_{t,y,ROS447r.i} = \varphi_0 + \delta_1 IP_{t,y} + \omega_{OL} D_{Apr\ 2010=1} + \omega_{OL} D_{Feb\ 2013=1} + ARIMA\epsilon_{t,y}\ (8,1,0)(0,0,0)_{12}$

[7.89] Model notes:
1. This is a special contract customer. In Oregon, special contract customers have a different regulatory status during rate case proceedings.

[7.90] $THM/C_{t,y,ROS456.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{July\ 2013=1} + ARIMA\epsilon_{t,y}\ (7,1,0)(1,0,0)_{12}\ for\ y = 2008 \uparrow$

[7.90] Model notes:
1. Model is restricted to 2008 ↑ significant step-down in UPC compared to earlier periods. This likely reflects an increasing step-function of customers until 2010. Between 2005 and 2014 the number of customers increased from 1 to 8.

Industrial Sector, Customers:

[7.91] $C_{t,y,ROS420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.91] Model notes:
1. Due to the Compass software conversion, February 2015 is excluded from the historical data. The conversion resulted in a double counting of customers in February 2015. Therefore, including this month leads to a significant over-forecast of customers.

[7.92] $C_{t,y,ROS424.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.91] Model notes:
1. Schedule appears to have died. No customers are currently being reported.

[7.93] $C_{t,y,ROS440.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.94] $C_{t,y,ROS456.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

3. Klamath Falls, OR Forecasting Models

The forecasting models for the Klamath Falls region (Klamath County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

[7.95] $THM/C_{t,y,KLM410.r} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \lambda RAP_{t,y-1,OR410} +$
$+ \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Apr\ 2007=1} + \omega_{OL} D_{Dec\ 2008=1} + \omega_{OL} D_{Nov\ 2009=1} + \omega_{OL} D_{Feb\ 2011=1} +$
$ARIMA\epsilon_{t,y}\ (10,0,0)(0,0,0)_{12}$

[7.95] Model notes:
1. AHS is not included because its impact is unstable and not statistically significant.

Exhibit 3

[7.96] $THM/C_{t,y,KLM420.r} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \epsilon_{t,y} \ \ for\ \ t,y = July\ 2011 \uparrow$

[7.96] Model notes:
1. Potential non-white noise error and non-stationarity due to a short time-series used to estimate the model.
2. Model restricted to July 2011 ↑ because of a significant change in behavior compared to earlier periods.
3. Schedule has died; no longer showing load or customers.

Residential Sector, Customers:

[7.97] $C_{t,y,KLM410.r} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2007\uparrow=1} + \gamma_{RAMP} T_{Jan\ 2007} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\ (6,1,0)(0,0,0)_{12}$

[7.97] Model notes:
1. SC dummy and ramping time trend control for a change in the time-path of customer growth staring in January 2007.

[7.98] $C_{t,y,KLM420.r} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.98] Model notes:
1. Schedule appears to be dying out.

Commercial Sector, THM:

[7.99] $THM/C_{t,y,KLM420.c} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Aug\ 2012\uparrow=1} + \omega_{OL} D_{Aug\ 2012=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(2,0,0)_{12}\ for\ y = 2008 \uparrow$

[7.99] Model notes:
1. Model is restricted to 2008 ↑ because of significant problems fitting a model to the entire series.
2. SC dummy controls for a step-down in base-load UPC starting in August 2012.
3. Work is ongoing for statistical controls so that 2005-2007 can be added to the estimation period.

[7.100] $THM/C_{t,y,KLM424.c} = \beta_0 + \beta_1 HDD_{t,y}^{AVA} + \beta_2 (HDD_{t,y}^{AVA})^2 + \beta_3 QHDD_{t,y}^{AVA} + \beta_4 (QHDD_{t,y}^{AVA})^2 + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ y = 2009 \uparrow$

[7.100] Model notes:
1. Model is restricted to 2009 ↑ because of a significant step-up in UPC and change in seasonality compared to earlier periods.
2. Work is ongoing for statistical controls so that 2005-2008 can be added to the estimation period.

[7.101]
$THM/C_{t,y,KLM440.c} = \frac{1}{N}\sum_{j=1}^{N}(THM/C_{t-j})\ \ for\ t,y = Feb\ 2008 \uparrow\ for\ N = total\ available\ months\ of\ data\ since\ Febuary\ 2007$

[7.101] Model notes:
1. Model is restricted to February 2007 ↑ because schedule does not start until February 2007.
2. No identifiable trend or seasonality in this schedule.

Exhibit 3

Commercial Sector, Customers:

[7.102] $C_{t,y,KLM420.c} = \beta_0 + \beta_1 C_{t,y,KLM410.r} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2005=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}$

[7.102] Model notes:
1. $C_{t,y,KLM410.r}$ are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2.

[7.103] $C_{t,y,KLM424.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.104] $C_{t,y,KLM440.c} = \frac{1}{N}\sum_{j=1}^{N} C_{t-j}\ for\ N = total\ available\ months\ of\ data\ history\ since\ 2007$

Industrial Sector, THM:

[7.105] $THM/C_{t,y,KLM420.i} = \beta_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Jan\ 2010-Feb\ 2010=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\ (3,0,0)(0,0,0)_{12}\ for\ t,y = June\ 2008 \uparrow$

[7.105] Model notes:
1. Model is restricted to June 2008 ↑ because schedule does not start until December 2006.

[7.106] $THM/C_{t,y,KLM424.i} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (2,0,0)(0,0,0)_{12}\ for\ t,y = August\ 2009 \uparrow$

[7.106] Model notes:
1. Model is restricted to August 2009 ↑ because schedule does not start until April 2009, and April and May 2009 are extreme outliers.

[7.107] $THM_{t,y,KLM440.i} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Sep\ 2008=1} + \omega_{OL} D_{Sep\ 2009=1} + \omega_{OL} D_{Oct\ 2010=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{Sept\ 2013=1} + \omega_{OL} D_{Oct\ 2013=1} + \epsilon_{t,y}\ for\ y = 2008 \uparrow$

[7.107] Model notes:
1. Model is restricted to 2008 ↑ because of a significant change in seasonality compared to earlier periods.

[7.108]
$THM_{t,y,KLM447w.i} = \beta_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{Jul\ 2012=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[7.108] Model notes:
1. Model is restricted to 2008 ↑ because of a significant step-down in load compared to earlier periods.
2. This is a special contract customer. In Oregon, special contract customers have a different regulatory status during rate case proceedings.

[7.109]
$THM/C_{t,y,KLM456.i} = \varphi_0 + \delta_1 IP_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Nov\ 2013\uparrow=1} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{May\ 2012=1} + \omega_{OL} D_{Dec\ 2014=1} + ARIMA\epsilon_{t,y}\ (4,1,0)(0,0,0)_{12}\ for\ y = 2008 \uparrow$

[7.109] Model notes:
1. Model is restricted to 2008 ↑ because of a significant change in seasonality compared to earlier periods.
2. SC dummy controls for sudden step-up in UPC starting in November 2013.

Exhibit 3

Industrial Sector, Customers:

[7.110] $C_{t,y,KLM420.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.111] $C_{t,y,KLM424.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.112] $C_{t,y,KLM440.i} = 1\ if\ THM_{KLM,440.i} > 0$

[7.113] $C_{t,y,KLM456.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

4. La Grande, OR Forecasting Models

The forecasting models for the La Grande region (Union County) are given below for the residential, commercial, and industrial sectors:

Residential Sector, THM:

[7.114]
$THM/C_{t,y,LaG410.r} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2(HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4(QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Jan\ 2009\uparrow=1} + \omega_{OL} D_{Feb\ 2007=1} + + \omega_{OL} D_{May\ 2011=1} + \omega_{OL} D_{Jun\ 2011=1} + \omega_{OL} D_{Mar\ 2014=1} + ARIMA\epsilon_{t,y}\ (12,0,0)(0,0,0)_{12}$

[7.114] Model notes:
1. RAP does not appear in the model because the coefficient’s sign is unstable and statistically insignificant.
2. The variable lnT reflects a general control for multiple factors lowering UPC, including the impact of RAP.
3. SC dummy controls for a step-down in UPC.
4. AHS is not included because its impact is unstable and not statistically significant.

[7.115] $THM/C_{t,y,LaG420.r} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2(HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4(QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2012=1} + ARIMA\epsilon_{t,y}\ (1,0,0)(0,0,0)_{12}\ for\ t,y = June\ 2010\ \uparrow$

[7.115] Model notes:
1. The short time-series used to estimate the model reflects a significant change in behavior in 2010 that cannot be fully controlled for.
2. This schedule in appears to be losing customers and load.

Residential Sector, Customers:

[7.116] $C_{t,y,LaG410.r} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_{RAMP} T_{Jan\ 2008} + \omega_{OL} D_{Dec\ 2009=1} + \omega_{OL} D_{Jul\ 2006=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\ (9,1,0)(1,0,0)_{12}\ for\ y = 2007\uparrow$

[7.116] Model notes:
1. Model is restricted to 2007 ↑ because of significant decline in customer growth following the Great Recession. Including pre-2007 periods produces forecasted growth rates that are too high compared to the post- recession growth trend.
2. Ramping time trend controls for a change in the time-path of customer growth staring in January 2008.
3. Work is ongoing for statistical controls so that 2005-2006 can be added to the estimation period.

Exhibit 3

[7.117] $C_{t,y,LaG420.r} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.117] Model notes:
1. This schedule had died; reported customers have fallen to zero.

Commercial Sector, THM:

[7.118] $THM/C_{t,y,LaG420.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \omega_{SC} D_{Aug\ 2012\uparrow=1} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\ (3{,}0{,}0)(0{,}0{,}0)_{12}\ for\ y = 2008\uparrow$

[7.118] Model notes:
1. Model is restricted to 2007 ↑ because of a significant change in seasonality compared to earlier periods.
2. Work is ongoing for statistical controls so that 2005-2006 can be added to the estimation period.
3. SC dummy controls for a significant step-down in base-load for August 2012 ↑.

[7.119] $THM/C_{t,y,LaG424.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} +$
$\omega_{OL} D_{Jan\ 2011=1} + ARIMA\epsilon_{t,y}\ (2{,}0{,}0)(0{,}0{,}0)_{12}\ for\ t,y = June\ 2010\uparrow$

[7.119] Model notes:
1. Model is restricted to June 2010 ↑ because of a significant change in seasonality compared to earlier periods.

[7.120] $THM/C_{t,y,LaG444.c} = \frac{1}{N}\sum_{j=1}^{N}(THM/C_{t,y-j})\ for\ y = 2011\uparrow$

[7.120] Model notes:
1. Model is restricted to 2011 ↑ because the schedule does not start until 2011.

[7.121] $THM/C_{t,y,LaG440.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{SC} D_{Sept\ 2013\uparrow=1} + \omega_{OL} D_{July\ 2014=1} +$
$\omega_{OL} D_{Aug\ 2014=1} + \omega_{OL} D_{Oct\ 2014=1} + \omega_{OL} D_{Sept\ 2013=1} + ARIMA\epsilon_{t,y}\ (3{,}0{,}0)(0{,}0{,}0)_{12}\ for\ t,y = Sept\ 2009\uparrow$

[7.121] Model notes:
1. Model is restricted to September 2009 ↑ because of a significant change in seasonality compared to earlier periods. There is a sharp change in seasonality in June/July 2014. It's not clear if this change is permanent.
2. SC dummy controls for a step-up in UCP starting in September 2013.

[7.122] $THM/C_{t,y,LaG456.c} = \theta_0 + \theta_1 HDD_{t,y}^{AVA} + \theta_2 (HDD_{t,y}^{AVA})^2 + \theta_3 QHDD_{t,y}^{AVA} + \theta_4 (QHDD_{t,y}^{AVA})^2 + \boldsymbol{\omega_{SD} D_{t,y}} +$
$\omega_{OL} D_{Mar\ 2009=1} + \omega_{OL} D_{May\ 2013=1} + ARIMA\epsilon_{t,y}\ (1{,}0{,}0)(0{,}0{,}0)_{12}$

[7.122] Model notes:
1. Base load forecast months are often negative; these are set to zero in the forecast spreadsheet.

Commercial Sector, Customers:

[7.123] $C_{t,y,LaG420.c} = \theta_0 + \theta_1 C_{t,y,LaG410.r} + \omega_{OL} D_{Dec\ 2008=1} + \omega_{OL} D_{Mar\ 2011=1} +$
$ARIMA\epsilon_{t,y}\ (1{,}1{,}0)(0{,}0{,}0)_{12}\ for\ y = 2008\uparrow$

[7.123] Model notes:
1. $C_{t,y,LaG410.r}$ are residential customers from residential schedule 410. They are being used as a forecast driver because of the historical positive correlation between residential and commercial customer growth. See Tables 5.1 and 5.2.
2. Model is restricted to 2008 ↑ because of significant change in seasonality compared to earlier periods.

Exhibit 3

[7.124] $C_{t,y,LaG424.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.125] $C_{t,y,LaG444.c} = 1\ if\ (THM/C_{t,y})_{Lag,444.c} > 0$

[7.126] $C_{t,y,LaG440.c} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

[7.127] $C_{t,y,LaG456.c} = C_{t-1}\ (Stable\ Customer\ Base;\ No\ Forecasting\ Model\ Required)$

Industrial Sector, THM:

[7.128] $THM/C_{t,y,LaG440.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Oct\ 2008\ =1} + \omega_{OL} D_{Jan\ 2010\ =1} + \omega_{OL} D_{Sept\ 2012\ =1} + \omega_{OL} D_{Feb\ 2013\ =1} + \omega_{OL} D_{Nov\ 2013\ =1} + \omega_{OL} D_{Sept\ 2014\ =1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}$

[7.129] $THM/C_{t,y,LaG444.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Oct\ 2007\ =1} + \omega_{OL} D_{Sept\ 2008\ =1} + \omega_{OL} D_{Nov\ 2010\ =1} + \omega_{OL} D_{Jan\ 2011\ =1} + + \omega_{OL} D_{July\ 2012\ =1} + \omega_{OL} D_{Sept\ 2012\ =1} + \omega_{OL} D_{April\ 2013\ =1} + \omega_{OL} D_{July\ 2014\ =1} + ARIMA\epsilon_{t,y}\ (5,0,0)(0,0,0)_{12}$

[7.130] $THM/C_{t,y,LaG456.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Oct\ 2008\ =1} + \omega_{OL} D_{Dec\ 2014\ =1} + \omega_{OL} D_{Mar\ 2015=1} + ARIMA\epsilon_{t,y}\ (5,1,0)(0,0,0)_{12}\ for\ t,y = July\ 2008 \uparrow$

[7.130] Model notes:
1. Model is restricted to July 2008 ↑ because significant step-down in UPC and seasonality compared to earlier periods.

Industrial Sector, Customers:

[7.131] $C_{t,y,LaG440.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2007\ =1} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Jan\ 2010\ =1} + \omega_{OL} D_{Aug\ 2011\ =1} + \epsilon_{t,y}$

[7.132] $C_{t,y,LaG444.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \boldsymbol{\omega_{OL} D_{t,y}} + ARIMA\epsilon_{t,y}\ (9,0,0)(0,0,0)_{12}$

$(\ \boldsymbol{\omega_{OL} D_{t,y}} = Aug\ 2007, Sept\ 2008, Jan\ 2010, Aug\ 2011, Aug\ 2012, Nov\ 2012, Dec\ 2012, Jan\ 2013, Feb\ 2013, Jan\ 2014 outliers\ for\ )$

[7.133] $C_{t,y,LaG456.i} = \frac{1}{12}\sum_{j=1}^{12} C_{t-j}$

Exhibit 4

[7.57] $THM_{t,y,MED444.c} = \beta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\,(1{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = January\ 2004 \uparrow$

[7.59] $THM/C_{t,y,MED456.c} = \alpha_0 + \alpha_1 HDD^{AVA}_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Sept\ 2009=1} + \omega_{OL} D_{Mar\ 2013=1} + \omega_{OL} D_{Dec\ 2013=1} + ARIMA\epsilon_{t,y}\,(12{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = January\ 2004 \uparrow$

[7.65] $THM/C_{t,y,MED420.i} = \alpha_0 + \alpha_1 HDD^{AVA}_{t,y} + \alpha_2 (HDD^{AVA}_{t,y})^2 + \alpha_3 QHDD^{AVA}_{t,y} + \alpha_4 (QHDD^{AVA}_{t,y})^2 + \delta_1 IP_{t,y} + \omega_{OL} D_{March\ 2011=1} + \boldsymbol{\omega_{SD} D_{t,y}} + ARIMA\epsilon_{t,y}\,(1{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = December\ 2006 \uparrow$

[7.77] $THM/C_{t,y,ROS420.c} = \varphi_0 + \varphi_1 HDD^{AVA}_{t,y} + \varphi_2 (HDD^{AVA}_{t,y})^2 + \varphi_3 QHDD^{AVA}_{t,y} + \varphi_4 (QHDD^{AVA}_{t,y})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 2011=1} + ARIMA\epsilon_{t,y}\,(8{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = January\ 2004 \uparrow$

[7.78] $THM/C_{t,y,ROS424.c} = \varphi_0 + \varphi_1 HDD^{AVA}_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Oct\ 2007=1} + \omega_{OL} D_{Mar\ 2011=1} + \omega_{OL} D_{Feb\ 2013=1} + ARIMA\epsilon_{t,y}\,(9{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = January\ 2004 \uparrow$

[7.78] Model notes:
1. Omitted $\omega_{OL} D_{July\ 2009=1}$ in order to avoid "Parameter estimation failed" error message in SAS statistical software.

[7.80] $THM/C_{t,y,ROS456.c} = \varphi_0 + \varphi_1 HDD^{AVA}_{t,y} + \varphi_2 (HDD^{AVA}_{t,y})^2 + \varphi_3 QHDD^{AVA}_{t,y} + \varphi_4 (QHDD^{AVA}_{t,y})^2 + \omega_{OL} D_{July\ 2014=1} + ARIMA\epsilon_{t,y}\,(1{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = November\ 2009 \uparrow$

[7.81] $C_{t,y,ROS420.c} = \varphi_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \gamma_1 T + \omega_{OL} D_{Jan\ 2008=1} + \omega_{OL} D_{Mar\ 2009=1} + \omega_{OL} D_{Feb\ 2015=1} + ARIMA\epsilon_{t,y}\,(6{,}1{,}0)(0{,}0{,}0)_{12} \quad for\ y = January\ 2004 \uparrow$

[7.81] Model notes:
1. Model uses Staff's Schedule 410, residential, Roseburg, customer forecast output.

[7.102] $C_{t,y,KLM420.c} = \beta_0 + \beta_1 C_{t,y,KLM410.r} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2005=1} + ARIMA\epsilon_{t,y}\,(12{,}1{,}0)(0{,}0{,}0)_{12} \quad for\ y = January\ 2004 \uparrow$

[7.108]
$THM_{t,y,KLM447w.i} = \beta_0 + \delta_1 IP_{t,y} + \delta_2 HS_{t,y} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Feb\ 2008=1} + \omega_{OL} D_{Jul\ 2012=1} + ARIMA\epsilon_{t,y}\,(1{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = 2008 \uparrow$

[7.108] Model notes:
1. HS is lagged West Housing Starts valuation.

[7.122] $THM/C_{t,y,LaG456.c} = \theta_0 + \theta_1 HDD^{AVA}_{t,y} + \theta_2 (HDD^{AVA}_{t,y})^2 + \theta_3 QHDD^{AVA}_{t,y} + \theta_4 (QHDD^{AVA}_{t,y})^2 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Mar\ 2009=1} + \omega_{OL} D_{May\ 2013=1} + ARIMA\epsilon_{t,y}\,(1{,}0{,}0)(0{,}0{,}0)_{12} \quad for\ y = January\ 2004 \uparrow$

Exhibit 4

[7.128] $THM/C_{t,y,LaG440.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Oct\ 2008=1} + \omega_{OL} D_{Jan\ 2010=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{Feb\ 2013=1} + \omega_{OL} D_{Nov\ 2013=1} + \omega_{OL} D_{Sept\ 2014=1} + ARIMA\epsilon_{t,y}\ (12,1,0)(0,0,0)_{12}\quad for\ y = January\ 2004 \uparrow$

[7.129] $THM/C_{t,y,LaG444.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Oct\ 2007=1} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Nov\ 2010=1} + \omega_{OL} D_{Jan\ 2011=1} + +\omega_{OL} D_{July\ 2012=1} + \omega_{OL} D_{Sept\ 2012=1} + \omega_{OL} D_{April\ 2013=1} + \omega_{OL} D_{July\ 2014=1} + ARIMA\epsilon_{t,y}\ (5,0,0)(0,0,0)_{12}\quad for\ y = January\ 2004 \uparrow$

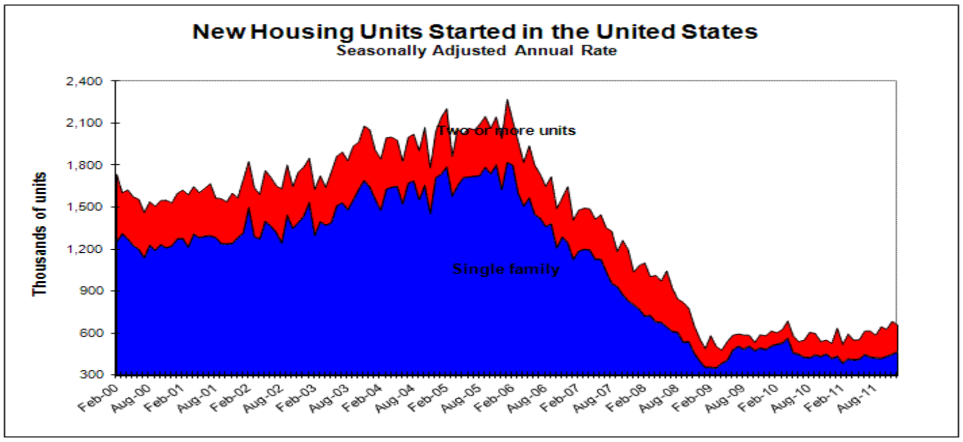
[7.131] $C_{t,y,LaG440.i} = \theta_0 + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2007=1} + \omega_{OL} D_{Sept\ 2008=1} + \omega_{OL} D_{Jan\ 2010=1} + \omega_{OL} D_{Aug\ 2011=1} + \epsilon_{t,y}\quad for\ y = January\ 2004 \uparrow$

Exhibit 5

Housing Starts/Building Permits

Importance: ***

Definition: The housing industry accounts for about 27% of investment spending and 5% of the overall economy. Housing starts is important because it is a leading indicator. Sustained declines in housing starts slow the economy and can push it into a recession. Likewise, increases in housing activity triggers economic growth.



Related Indicators:

Source: Bureau of the Census of the U.S. Department of Commerce

Frequency: Monthly

Availability: Two to three weeks following the reported month

Direction:

Timing:

Volatility: Moderate

Likely Impact on Financial Markets:

> **Interest Rates:** Larger-than expected monthly increase or increasing trend is considered inflationary, causing bond prices to drop and yields and interest rates to rise.
>
> **Stock Prices: �.**
>
> **Exchange Rates: ....**

Exhibit 5

Ability to affect markets:

Analysis of the Indicator:

Housing data tracks the four major regions of the U. S.: Northeast, Midwest, South, and West.

Building permit data is released at the same time as housing starts. Permit activity provides insight into housing and overall economic activity in upcoming months. It is so important that it is included in the index of leading economic indicators.

Housing activity is directly impacted by mortgage rates. Higher interest rates increase housing costs and reduce the number of qualified borrowers, thus, a decline in home sales and drop-off in starts. Conversely, lower interest rates increases housing affordability and spurs homes sales and housing starts.

Housing data can have a significant impact on the bond market. A stronger-than-expected report is viewed negatively, suggesting strong growth and possible inflationary side-effects. A weak report has the opposite effect on the market.

WEB Links

A Graph of the latest Housing Starts data from The Economic Statistics Briefing Room of the White House.

The latest Housing Starts report from BLS.

CASE: UG 288
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Load Forecasting, Decoupling, Public Purpose Charge

Opening Testimony

October 16, 2015

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

A. My name is Suparna Bhattacharya. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. This testimony presents Staff's analysis and recommendations regarding Avista Corporation's (Avista or Company) residential sales forecast, revenue adjustments, decoupling mechanism, and the public purpose charge.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following exhibits for this docket:

Exhibit Staff/1001 Witness Qualification
Exhibit Staff/1002 Avista's responses to Data Requests (DRs)

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. What are the main conclusions from your analysis?

A. The main conclusions are summarized below:

1. Residential Load Forecast: In this proceeding, Staff has reviewed the Company's June 2015 forecasting models that were provided by the Company in response to Staff Data Request 193 (Exhibit 1002). Staff notes that the Company's forecasts provided in these data requests were not incorporated in the Company's filed revenue model. Staff is proposing model

specifications for customer and use-per-customer forecasts that best fit the data and capture the key factors driving the forecasts. Based on Staff's econometric models, Avista's test year sales for residential customers served under Schedule 410 will increase by 0.12% compared to the Company's residential forecasts submitted through data requests.

Since the filed revenue model is not updated based on the Company's June 2015 forecasts, Staff is recommending test year revenue adjustments relative to the Company's revenue proposed in the revenue model. Based on Staff's analysis, test year revenue decreases by approximately $867,796. Staff witness St. Brown in his testimony (Staff/900) has reviewed forecasts for non-residential customers and revenue adjustments for these groups are based on his analysis.

2. Decoupling Mechanism: After reviewing the Company's proposed decoupling mechanism and existing public purpose funds, Staff proposes that the Commission:
   a. approve the Company's request to establish decoupling in its Oregon service territories effective 2016;
   b. establish an opportunity to review the proposed mechanism by September, 2019 to allow Staff and other parties to recommend any changes;
   c. implement the Company's proposed decoupling mechanism with some modifications. Two deferral accounts to explicitly account for weather

and conservation should be created. This would allow the Commission and stakeholders to analyze the decoupling adjustment associated with weather and understand the factors causing the changes in the decoupling rates;

d. establish a new tariff, Schedule 475, effective 2017, to administer rate adjustments associated with the new decoupling mechanism;

e. establish a separate public purpose tariff to collect costs for administering and delivering energy efficiency programs. In 2016, Avista will still be offering conservation programs and a single program will be offered by the ETO. The monies collected through this tariff would go to Avista in 2016. In 2017, the monies collected through this tariff should be transferred to the Energy Trust of Oregon (ETO). The tariff should be revised to match the ETO's administrative costs and expenses needed to offer conservation programs to Avista's customers in 2017;

f. allow the Company to retain collection for funding low income household programs, delivered by Community Action Agencies: Avista Oregon Low Income Energy Efficiency Program (AOLIEE) and the Low Income Rate Assistance Program (LIRAP). Effective 2017, a separate tariff to administer AOLIEE program should be established. The Company should continue Schedule 493 tariff for collecting expenses related to LIRAP.

ISSUE 1, RESIDENTIAL LOAD FORECAST

Q. Please summarize the Company's load forecast approach.

A. For the residential forecast group, the total load is measured as the product of Use-Per-Customer (UPC) and the number of customers. The Company developed an Auto Regressive Integrated Moving Average (ARIMA) based time series model[1] to forecast UPC and customers for the residential rate Schedule 410, an ARIMA-based time series model to forecast UPC for the residential rate Schedule 420, and simple regression models to forecast a small group of residential customers served under Schedule 420. These models are developed to forecast load for the four service territories– Medford, Roseburg, Klamath Falls and La Grande. Adding in the loads from all regions for a specific schedule gives the total load for that rate schedule.[2]

The Company's UPC model uses "seasonal dummies" (SDs), Heating Degree Days (HDDs), gas price, trend function, dummies for outliers (OLs), and auto-regressive errors as explanatory variables to predict therms per customer for the test year. The number of customers is forecasted using SDs, OLs, and auto-regressive errors as explanatory variables.[3] Only the Medford customer model has an economic driver- population as an explanatory variable.[4]

Q. Please describe Staff's approach to analyze residential load forecast.

A. To ensure that load forecasts generated for the test year are robust and accurate Staff:

[1] AVISTA/701, Forsyth/2 describes ARIMA model structures.
[2] AVISTA/701, Forsyth/1-3
[3] AVISTA/701, Forsyth/1-3
[4] Staff/1002, Avista Response to Staff Data Request 282

a. thoroughly analyzed the Company's methodology and models used to forecast UPC and number of customers;
b. verified the available data used for the analysis;
c. reviewed the Company's response to Staff's 15 DRs;
d. developed alternate ARIMA models to evaluate and compare model performances; and
e. discussed forecasting issues with the Company

Q. Please explain your Table 1 shown below.

A. Table 1 provides a high-level summary of Staff's test year residential load forecast analysis for the four service territories.

Table 1. Staff's Proposed Changes to Residential Load Forecast

	Medford	Roseburg	Klamath Falls	La Grande
Models				
Customer	AVA model	Staff model	Staff model	Staff model
UPC	Staff model	AVA model	AVA model	AVA model
Effects				
Customer	NA	0.58% increase	0.078% increase	0.004% decrease
UPC	0.037% increase	NA	NA	NA
Load	0.038% increase	0.56% increase	0.074% increase	0.039% increase

Staff has estimated different time series ARIMA models. The model that best fits the data and explains the factors driving the Company's test year sales and customers is selected. The key factors include population and economic growth, weather conditions and the price of natural gas. "AVA model" indicates that Staff accepts the Company's latest forecasting model[5], while "Staff model" indicates that alternative models are proposed by Staff. The final load adjustments with Staff's higher customer or UPC forecasts are expressed in percentages. For example, in Medford, 0.038% increase in load means that Staff's adjustments result in approximately 0.038% higher load than that proposed by the Company in this filing.

For each region, Staff now presents a detailed discussion of the steps involved to reach the conclusions presented in Table 1.

1. Medford

Customer Forecast: Staff agrees with the Company's proposed customer forecast model. Following discussions with Staff in its last rate case (UG 284), the Company integrated population as an explanatory variable to identify the effect of population on customer count. The current version of the Schedule 410 customer forecast model reflects this change.[6] In the last rate case, an adjustment for population growth was made after a baseline customer forecast was generated. Staff appreciates that the Company has adopted Staff's suggestion and verifies that the population coefficient in the integrated model is positive and significant, as expected. This change in methodology corrects the omitted variable bias and also simplifies the procedure as the regression coefficient attached to population directly captures the relationship between population and customers. Staff also reviewed the intervention variables added as explanatory variables by running the Company's model in SAS. Staff

[5] Staff/1002, Avista Response to Staff Data Request 193
[6] Staff/1002, Avista Response to Staff Data Request 282

notes that these variables effectively control for outliers and pre- and post-recession effects of the estimation time period January, 2005 through April, 2015 (these issues were also raised by Staff in the last rate case). The error correction terms (AR term) produce the minimum Akaike Info Criterion (AIC) and Schwarz Criterion (SBC) values.[7]

__UPC Forecast:__ Staff proposes an alternative UPC model that better captures the error assumptions and generates lower AIC and SBC values. The Company's current UPC model (that includes HDDs, natural gas price, seasonal dummies, intervention, and trend as explanatory variables) performs better with Staff's proposed adjustment ARIMA $(8,0,0)(0,0,0)_{12}$. ARIMA order selection process is an important procedure for time series models and should provide minimum AIC and SBC values. Staff generated this term using order selection test and analyzing autocorrelation and partial autocorrelation functions. AR (8) generates lower criterion values (AIC = 262, SBC = 347) than AR (11), as proposed by the Company (AIC = 264, SBC = 357). Staff has used the Company's HDDs and price data for this analysis. Staff reviewed the Company's 20-year moving average for defining normal weather over the forecast period and accepts the methodology.[8]

__Load Forecast:__ Based on Staff's adjustments, the residential load for the Medford region is predicted to be approximately 0.038% higher than the Company's forecast.

[7] Lower AIC and SBC values indicate better model performance.
[8] Staff/1002, Avista Response to Staff Data Request 243

2. Roseburg, Klamath Falls and La Grande

<u>Customer Forecast:</u> For customer forecast models, Staff is proposing to include population as an independent variable. Staff developed alternate integrated models with population as the key regression variable (along with seasonal dummies and intervention variables) to predict customers for the Roseburg, Klamath Falls and La Grande regions. Similar to the Medford customer model, Staff's proposed customer models for these three regions correct the omitted variable bias and the effect of population on customers is not captured by either seasonal or intervention variables. Staff has used the Global Insight county-based population data provided by the Company. [9] The regression coefficients representing the population variable are significant and show a positive association with the response variable- customer counts.

Staff's customer forecasts increases by 0.58% and 0.078% for Roseburg and Klamath Falls, and decreases by 0.004% for La Grande, relative to the Company's forecast.

In response to Staff's data request, the Company explains that since population and customer growth in these areas are relatively low, a simple time series models are developed that do not use population as an independent variable.[10] Staff asserts that the coefficients of the variables in the Company's current residential customer count models are capturing the effects of the key economic driver- population that is missing in the model.

[9] Staff/1002, Avista Response to Staff Data Request 197 Supplemental
[10] Staff/1002, Avista Response to Staff Data Request 244

Staff also identifies that for these three regions, the Company has not used the updated customer data series for forecasting purpose. The actual estimation period is from January, 2005 through April 2015; however, the Company's customer models exclude April from the analysis.[11] Staff's alternate models take into account this data error.

UPC Forecast: Staff has reviewed UPC models for these three regions[12] and agrees to the Company's models and forecast results. Identification of error correction terms, as well as selection of intervention variables and outliers, were appropriately done and the proposed model specifications produced minimum AIC and SBC values.

Load Forecast: With Staff's customer count adjustments, the load is approximately 0.56% higher for Roseburg, 0.074% higher for Klamath Falls, and 0.039% higher for La Grande. All these percentage increases are higher as compared to the Company's proposed test year load prediction for these regions.

Q. Please provide Staff's revenue adjustments.

A. Staff incorporated the inputs (customers and total therms) generated from Staff's models into the Company's filed revenue requirement model to calculate the increase/decrease in revenue for all schedules for the test year 2016.[13] Test year revenue decreases by approximately $$867,796.

[11] Staff/1002, Avista Response to Staff Data Request 301
[12] Staff/1002, Avista Response to Staff Data Requests 279, 280, and 281
[13] Staff/1002, Avista Response to Staff Data Requests 300

ISSUE 2, DECOUPLING AND PUBLIC PURPOSE CHARGE

Q. Please summarize the Company's proposed decoupling mechanism.

A. In this general rate case, the Company is proposing a revenue-per-customer decoupling mechanism that would compare the actual non-weather normalized revenue to the expected revenue determined on a per-customer basis. This mechanism would allow the Company to recover the Commission-approved fixed costs through volumetric energy rates if gas usage per customer declines between general rate cases. Thus, the disincentive to promote conservation practices would be removed. Customers will benefit as over-collected revenues would be credited if a winter is colder than normal and gas usage is higher than the forecast.[14]

The proposed decoupling mechanism would be applicable to two Rate Groups: Group 1 representing residential Schedule 410 customers and Group 2 representing non-residential customers served under Schedules 420, 424, 440 and 444 respectively.[15]

The high-level overview of the proposed deferral calculation is illustrated below:[16]

Approved Monthly Base Revenue Per Customer	x	Actual number of customers in a month	=	Allowed Monthly Base Revenue
Allowed Monthly Base Revenue	-	Actual Monthly Base Revenue	=	Decoupling Deferral Revenue

[14] AVISTA/900, Ehrbar/12-16
[15] AVISTA/900, Ehrbar/16
[16] AVISTA/900, Ehrbar/20

The deferral calculations apply for both residential and non-residential Rate Groups. The proposed mechanism does not incorporate weather normalization adjustments and thus, the actual monthly base revenue will be primarily calculated based on actual non-weather normalized volumes.

A new tariff Schedule 475 has been proposed that would describe this mechanism and identify temporary annual rate adjustments for each Rate Group based on decoupling deferred revenues and estimated therm sales.[17]

Q. Please describe Staff's proposal regarding the Company's decoupling mechanism.

A. Staff has reviewed the Company's proposed decoupling mechanism, data responses to Staff's eight data requests and the Commission-approved decoupling practices adopted by Cascade and Northwest Natural. Following are Staff's proposals:

Implementation of decoupling: Staff recommends the Commission allow the Company's request to establish a decoupling mechanism in its Oregon service areas, effective 2016. A review of the decoupling mechanism, however, should be required by the end of September 2019, to allow Staff and interested parties to recommend changes, if any.

Deferral accounts: The Company's proposed mechanism would create a deferral account that would defer the difference between allowed revenue and actual (not weather normalized) revenue. Staff proposes that two deferral accounts should be maintained to better understand the consumer's bill

[17] AVISTA/900, Ehrbar/23

variability due to weather variances and conservation or other economic shocks. The weather deferral account should record the difference between weather-normalized actual revenue and the actual revenue, while the conservation deferral account should track the difference between allowed and weather-normalized actual revenue. Adding up these two accounts will give the deferred revenue (allowed revenue – actual revenue), as proposed by the Company.

Staff believes that separately tracking these components will be informative and allow the Commission and stakeholders to analyze the decoupling adjustment associated with weather and understand the factors causing the changes in the decoupling rates.

Public purpose charge: Staff notes that the Company currently collects two types of public purpose funds in Oregon. The first is related to DSM/Energy Efficiency. The Company provides DSM services directly and does not utilize the ETO for administering DSM. This funding occurs through a tariff rate, Schedule 478, adjusted on an annual basis. Avista also collects monies through Schedule 478 for funding Avista Oregon Low Income Energy Efficiency Program (AOLIEE), delivered by Community Action Agencies.

The second public purpose fund is the Low Income Rate Assistance Program (LIRAP) that provides assistance to qualified low income households. The program and rates are administered through Schedule 493.

Staff proposes that the Company establish public purpose funds and transfer these funds to the ETO for delivering conservation programs to the Oregon customers. In 2016, Avista will still be offering conservation programs and a single program will be offered by the ETO. A separate public purpose tariff should be introduced in 2016 and funds collected through this tariff should go to the Company for administering and delivering conservation programs. In 2017, the ETO takes over, and funds collected through this tariff should be transferred to the ETO. The tariff should be revised to match the ETO's administrative costs and expenses needed to offer conservation programs to Avista customers in 2017.

The Company should continue collecting public purpose surcharge for funding Low Income Rate Assistance Program (LIRAP) and Avista Oregon Low Income Energy Efficiency Program (AOLIEE). A separate tariff, effective 2017 should be implemented for the AOLIEE program. Schedule 493 currently administering the rates associated with LIRAP should continue.

Q. Does this conclude your testimony?

A. Yes, it does.

CASE: UG 288
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Suparna Bhattacharya	
EMPLOYER:	Public Utility Commission of Oregon	
TITLE:	Senior Economist Energy Rates, Finance & Audit Division	
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301	
EDUCATION:	Ph.D.	Agricultural Economics University of Nebraska, Lincoln Specialization: Industrial Organization, Environmental & Natural Resource Economics, Production and Development Economics
	M.S.	Agricultural Economics University of Nebraska, Lincoln Specialization: Statistics, Econometrics
	B.A.	Economics Sambalpur University, India Specialization: Mathematical Economics
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April, 2014, with my current position being a Senior Economist, in the Utility Program's Energy - Rates, Finance and Audit Division. My current responsibilities include reviewing sales forecast, long run marginal generation and transmission costs, revenue requirements, tariff verification, decoupling, and energy efficiency. I have provided testimony in UE 283, UE 294, UG 284, and UG 287, filed comments in LC 61, LC 59, and prepared public meeting memos for UG 281, UG 301 and UG 295.	

CASE: UG 288
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT: State & Federal Regulation	
REQUEST NO.:	Staff – 181	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

REQUEST:

Avista/900-Ehrbar/Page 21, lines 8-10 state that two of the items that ultimately impact the Company's fixed cost recovery relate to weather and participation in the Company's energy efficiency programs.

a. Please explain how the proposed decoupling mechanism (Avista/900, Ehrbar/Page 16, lines 8-9) that compares the actual, non-weather adjusted revenues to the allowed revenue on a per-customer basis, captures the risk associated with weather variations and reduces the Company's disincentive to promote energy efficiency?
b. Avista/902 Ehrbar shows the new tariff schedule 475 that outlines the steps to calculate monthly decoupling deferral. Please explain how this monthly deferral account would track both weather and conservation variations without a weather normalization adjustment?

RESPONSE:

a. The Company recovers a substantial portion of its fixed costs in its variable energy rates. The goal of the Company's proposed decoupling mechanism is simply to ensure that the Company has the opportunity to recover its fixed costs, on a per customer basis. Without decoupling, if a winter is colder than normal, thereby increasing overall customer usage, customers would provide a higher level of fixed cost recovery than if weather was normal, and the Company would rebate the higher level of cost recovered. Likewise the Company would under-recover its fixed costs if weather was warmer than normal and customer usage was lower. With decoupling, variations in usage due to weather, as well variations due to other factors that affect customers usage (i.e., energy efficiency) would not impact the Company's recovery of its fixed costs.
b. The Company's proposed mechanism tracks the difference between the allowed decoupled revenue and actual decoupled revenue. Because the Company is interested in recovering its fixed costs approved by the Commission in a general rate case, on a per customer basis, a separate weather normalization adjustment is not required. Conducting a weather normalization adjustment would modify the "actual" decoupled revenue, which could lead to over- or under-recovery of fixed costs. This is explained further in the Company's response to Staff-182.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT: State & Federal Regulation	
REQUEST NO.:	Staff – 182	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

REQUEST:

Lines 14-16 of Avista/900 Ehrbar/Page 14 says "If weather were to be normalized as part of the mechanism, the mechanism would not provide the same level of fixed cost recovery as determined in the last general rate case". Please explain and if possible provide an illustrative example for the above statement using the time period 2010 through 2014, inclusive.

RESPONSE:

The Company's proposed mechanism tracks the difference between the actual decoupled revenue received from customers and the allowed decoupled revenue. This ensures that the Company receives recovery of the fixed costs that are embedded in customer's volumetric rates. For example, if the Company had a colder than normal winter, Avista may over-recover its fixed costs. Under the proposed mechanism, the amount of revenue received in excess of what is allowed would be deferred and returned to customers. If the Company normalized weather in this example, the effect would be to increase the "actual decoupled revenue", and therefore the difference between actual and allowed would be less (and could actually go from a rebate to a surcharge, as discussed below). The Company would retain the difference between the actual revenue and the weather normalized, and customers would only receive or be surcharged the difference between weather normalized revenue and allowed.

Provided as Staff_DR_182 Attachment A is an illustrative example of how normalizing weather would impact the "decoupled revenue." For this example, the Company used actual usage (Lines 1-7), and weather normalized usage (lines 9-15) for 2010 through 2014. The Company also used the actual billings for 2010-2014 as shown on lines 17-23. Lines 25-29 show the proposed volumetric rates in this case.[1] To determine the "Decoupled Revenue" for each year as shown on lines 30 and 31, the Company applied the proposed "Annual Decoupled Revenue Per Customer" to the actual number of customers for each year.[2] The resulting calculation is the illustrative allowed revenue per customer. Lines 33 and 34 show the illustrative "Actual Volumetric Base Rate Revenue from Rates" which is calculated by multiplying the proposed volumetric base rates by the annual actual customer usage. Under the Company's proposed Decoupling Mechanism, the Actual Volumetric Base Rate Revenue is compared to the Allowed Decoupled Revenue, with the difference/deferral shown in lines 36 and 37. Attachment A also

[1] The Company has not conducted an actual year-by-year study, so for this illustrative example it is using the proposed rates and per customer values proposed in this case.
[2] id.

shows the "Weather Normalized Volumetric Base Rate Revenue from Rates" (lines 39 and 40), and resulting difference between that, and the Allowed Decoupled Revenue, shown on lines 42 and 43.

What the results show based on comparing the level of fixed cost recovery using actual volumetric revenue (as proposed by the Company) on line 45 and using weather normalized revenue, as shown on line 46, is that in some years the Company would over recover its fixed costs (2011, 2012, and 2013) and in other years under recover its fixed costs (2010 and 2014).

As it relates to my previous example where there is a year with colder than normal weather, in looking at 2011 in the illustrative example, line 38 shows that under the Company's proposed mechanism, it would have rebated $3.2 million to customers because it received more revenue ($46.9 million – line 35) than what was allowed ($43.7 million – line 32). If, however, customer usage was weather normalized, the adjusted actual revenue would have been $42.7 million (line 41), and the Company would have recorded a deferral surcharge of approximately $1.1 million (line 44) when customers already provided $3.2 million more than expected. The result by using weather normalized usage is a net over recovery of $4.3 million (line 47).

In summary, the Company does not believe that customer usage should be weather normalized as it essentially defeats the purpose of the mechanism, that is, the recovery of the fixed costs that are embedded in customer's volumetric rates. Further, including the effects of weather in the mechanism is consistent with the Company's earnings test which does not normalize weather.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT: State & Federal Regulation	
REQUEST NO.:	Staff – 183	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

REQUEST:

Avista/ 904-Ehrbar/Page 3 of 4, lines 4 and 8 show weather-normalized therm delivery volumes for residential and non-residential customers. Please define: a) normal Heating Degree Days; and b) normal Cooling Degree Days; and provide cites for the source of each definition.

RESPONSE:

Included on p. 3 of Exhibit 904 are the monthly volumes for 2016 from the Company's natural gas load forecast. As discussed in detail by Company witness Dr. Forsyth, the Company assumes average or normal weather in the forecast period. As stated by Dr. Forsyth, starting in 2013, the Company moved to a 20-year moving average for the definition of normal weather.

Prior to 2013, NOAA's standard 30-year average was used. This means, each year the definition of normal weather is updated by moving the 20-year average ahead one year.

For heating and cooling degree days, the Company uses the NOAA standard calculation where you either subtract from 65 degrees (heating) or subtract 65 degrees from (cooling) the average daily temperature.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	07/15/2015
CASE NO.:	UG 288	WITNESS:	Patrick Ehrbar
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Patrick Ehrbar
TYPE:	Data Request	DEPT: State & Federal Regulation	
REQUEST NO.:	Staff – 184	TELEPHONE:	(509) 495-8620
		EMAIL:	pat.ehrbar@avistacorp.com

REQUEST:

Please refer to Avista/900, Ehrbar/Page 23. Please explain how did the Company determined 3% rate increase limitation test?

RESPONSE:

The Company has a 3% rate increase limitation test in its Washington electric and natural gas decoupling mechanisms. Avista used the same 3% test in its proposed mechanism for Oregon in an effort to align the mechanisms.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	07/07/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER:	Ryan Finesilver
TYPE:	Data Request	DEPT: State and Federal Regulation	
REQUEST NO.:	Staff – 185	TELEPHONE:	(509) 495-4873
		EMAIL: ryan.finesilver@avistacorp.com	

REQUEST:

Please provide the excel spreadsheet showing amount of monies collected annually by the Company for funding Energy Trust of Oregon (ETO) administered conservation programs by rate schedules from 2010 through 2015.

RESPONSE:

The Company provides DSM services directly and does not utilize the Energy Trust of Oregon for administering DSM. Please see Staff_DR_185 Attachment A for annual collections related to the DSM program.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	07/07/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER:	Ryan Finesilver
TYPE:	Data Request	DEPT: State and Federal Regulation	
REQUEST NO.:	Staff – 186	TELEPHONE:	(509) 495-4873
		EMAIL: ryan.finesilver@avistacorp.com	

REQUEST:

Please provide the excel spreadsheet showing annual expenses by rate schedules, incurred by ETO to deliver conservation programs, for each year from 2010 through 2014, inclusive.

RESPONSE:

The Company provides DSM services directly and does not utilize the Energy Trust of Oregon for administering DSM. Please see Staff_DR_186 Attachment A for annual expenses related to the DSM program.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED: 08/27/2015
CASE NO:	UG 288	WITNESS: Grant D. Forsyth/Patrick Ehrbar
REQUESTER:	PUC Staff - Bhattacharya and St. Brown	RESPONDER: Grant D. Forsyth/Joe Miller
TYPE:	Data Request	DEPT: Financial Planning & Analysis State and Federal Regulation
REQUEST NO.:	Staff – 193 Supplemental	TELEPHONE: (509) 495-2765/(509)495-4546
		EMAIL: grant.forsyth@avistacorp.com joe.miller@avistacorp.com

SUPPLEMENTAL RESPONSE:

(a): In the Company's response to Staff-193, base data for the most recent customer and use per customer (UPC) forecasts were provided. The Company is supplementing the response to Staff-193 in order to reflect the revised billing determinants from this most recent forecast in adjustment number 2.01 (2016 Test Year Revenue Adjustment). The effect of this revised adjustment is to increase Oregon net operating income by $3,608,000 ($4,099,000 in original filing) and a reduction to revenue requirement of $6,225,000 ($7,074,000 in original filing). The net effect of this adjustment is a revenue requirement <u>increase of $849,000 from the Company's original filing</u>. See the attachment labeled "Staff_DR_193 Supplemental Attachment A" for the workpapers supporting this revised adjustment.

During the analysis of the updated forecast data provided above, the Company discovered a formula error in its original filing which resulted in an incorrect assignment of usage to the individual rate blocks on Schedule 146. The resulting correction to the five usage blocks overstated revenue to Schedule 146 by $119,000 in the Company's original filing. The Company has corrected the assignment of usage to the individual rate blocks in the attachment labeled "Staff_DR_193 Supplemental Attachment A" discussed above.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED: 08/28/2015
CASE NO.:	UG 288	WITNESS: Grant D. Forsyth
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER: Grant D. Forsyth
TYPE:	Data Request	DEPT: Financial Planning & Analysis
REQUEST NO.:	Staff – 282	TELEPHONE: (509) 495-2765
		EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. For the Medford region, excel file SAS Parameters.xlsx file in the folder OR MED Sch 410r Cus shows the model specification for Medford customer forecast. The regression model includes AR terms, seasonal dummies, intervention variables and population variable JACKMSAPOP (significant and positive).

a. Please explain why the above model specification is different from the mathematical equation of the Medford residential customer forecasting model given in line 22 of Avista/701, Forsyth/3. Specifically explain why population variable is not included, as well as AR terms and intervention variables are different.

b. The population variable, JACKMSAPOP, is positive and significant. Please explain why and how the Medford baseline customer forecast model is further adjusted to match the population growth (Avista/700, Forsyth/5).

RESPONSE:

(a): Following discussions with staff in the last rate case, population was integrated in as a regression variable. In prior versions of the forecast, an adjustment for population growth was made after a base-line forecast had been generated. In other words, population was not an explicit regression variable. At the time Avista/701, Forsyth/3 was written, the new version of the model had not been completed, so the discussion focused on the procedure used in the June 2014 forecast.

(b): In the procedure for the June 2015 forecast, there are no further adjustments. The earlier procedure used in the June 2014 forecast made the simplifying assumption that Medford 410 residential customer growth would follow population growth. The new procedure allows the regression coefficient attached to JACKMSAPOP to determine the relationship between population and customers. The change in methodology did not create a large change in the forecast between the June 2014 and June 2015 forecasts.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED: 08/12/2015
CASE NO.:	UG 288	WITNESS: Grant D. Forsyth
REQUESTER:	PUC Staff - Bhattacharya	RESPONDER: Grant D. Forsyth
TYPE:	Data Request	DEPT: Financial Planning & Analysis
REQUEST NO.:	Staff – 244	TELEPHONE: (509) 495-2765
		EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Avista/700, Forsyth/8 states that an integrated customer forecast model with population as an explicit explanatory variable will better capture the relationship between residential customer growth and population growth.

a. Please explain clearly all the steps involved to develop the integrated model specification;

b. Explain all statistical tests performed that shows that the integrated model with population as an independent variable better captures the relationship between customer count and population;

c. Please provide the excel spreadsheet (with cell formulae intact) showing the customer forecasts generated from the integrated model;

d. Line 8 of Avista/700, Forsyth/8 mentions about the population data for the integrated customer forecast model. Please explain in detail how the monthly population data series is created for the historical and forecast period by interpolating annual historical population estimates. Provide the monthly population data used for the integrated model in an excel format with cell formulae intact; and

e. Please provide the information requested in parts (a), (b), (c), and (d) for Medford, Roseburg, Klamath and La Grande regions.

RESPONSE:

(a): The integrated model applies to the Medford region only. The Roseburg, Klamath, and La Grande regions rely on time-series models that do not use population as a regression variable. Since population and customer growth in these three areas is relatively low, relatively simple time-series models are effective for capturing their customer growth.

In the case of the Medford region, the first step was to obtain annual population estimates from the U.S. Census (as pulled from the BEA's county data base). The second step was to transform the annual population series to a monthly series by interpolation. The third step was to use the interpolated series in the regression model.

(b): The statistical tests for the new Medford schedule 410 model can be found as part of the Company's response to Staff_DR_193 Attachment B (see "OR MED Sch 410r Cus"). Tests for error white noise and stationary were all within acceptable limits, and the adjusted R^2 of the model is 0.997. The addition of both the population variable and a "ramping" time trend provided enough statistical controls to extend the model's estimation period back to 2005, a

period which fully includes Medford's housing bubble period. The model, as provided in Staff_DR_194 (Exhibit A), is:

$$\begin{aligned} C_{t,y,MED410.r} = \quad & \alpha_0 + \alpha_1 POP_{t,y,MED} + \boldsymbol{\omega_{SD} D_{t,y}} + \omega_{OL} D_{Dec\ 2005=1} \\ & + \omega_{SC} D_{Jan\ 2008\uparrow=1} + \gamma_{RAMP} T_{Jan\ 2008} + \omega_{OL} D_{Feb\ 2015=1} \\ & + ARIMA\epsilon_{t,y}\ (7,1,0)(0,0,0)_{12} \end{aligned}$$

Model notes:
1. SC dummy and ramping time trend control for a change in the time-path of customer growth staring in January 2008.

The estimation period for the model used in the previous rate case extended back to 2007. Without population directly in the model, using the 2005-2006 period in the estimation period generated customer forecasts that were too high given the Medford region's slow post-recession recovery.

Referring again to the Company's response to Staff_DR_193 Attachment A-Gas Data and Forecasts June 2015 shows the change in Medford's residential 410 customer forecast between the June 2014 forecast, which uses the previous methodology for population, and the June 2015 forecast, which uses the interpolated population series. For 2016 thorough 2020, there was an upward revision of about 0.1%. These values can be found under the tab "OR June 2015 Forecasts" starting in cell B-156.

(c): The all customer forecasts were submitted under the Company's response to Staff_DR_193 Attachment A-Gas Data and Forecasts June 2015; in this file, the Medford customer forecast can be found under the tab "OR June 2015 Forecasts" starting in cell B-44.

(d): Several issues arise when using population as an explanatory variable. First, U.S. Census county population estimates are generated on an annual basis but the customer data is monthly. Second, U.S. Census population estimates occur mid-year. The first issue can be solved by interpolation using the standard population growth model. The second issue can be solved by making sure the interpolated population values are applied recognize the timing of the estimates. Mathematically, the monthly interpolation between years is done treating the annual Census estimates (CPOP) as measuring population in June. Since the standard population model assumes continuous compounding, the June to June growth rate is calculated as:

[1] $r_y = ln\left(\frac{CPOP_{June,y}}{CPOP_{June,y-1}}\right)$

The growth rate in [1] is converted to a monthly rate, $m_y = r_y/12$. The rate m_y is then applied as follows between the historical CPOP estimates:

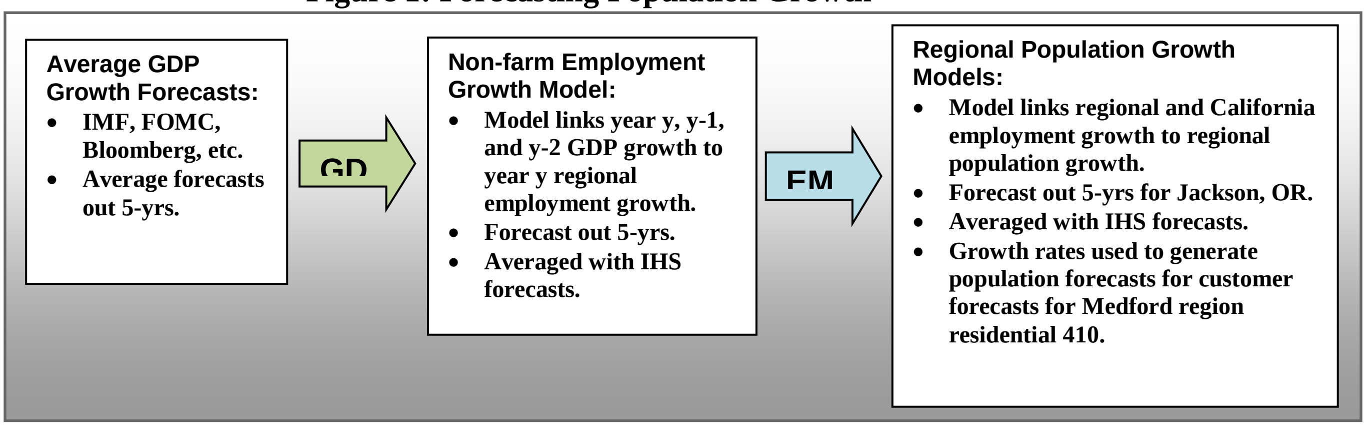
[2] $POP_t = POP_{t-1}(e^{m_y})\ for\ month\ t\ between\ June\ y-1\ and\ June\ y$

Using the above method produces an interpolated monthly series for Jackson County (the Medford MSA) were the June population estimates in the historical interpolated monthly series are the same as the official mid-year Census estimates used to calculate r_y. The monthly data used for the forecast has already been provided as part of the Company's response to Staff_DR_193 Attachment A-Gas Data and Forecasts June 2015; the Jackson County population values can be found under the tab "OR SAS Forecasting Data" starting in

cell E-2 under the column heading "JACKMSAPOP". The same interpolated series can be found in Staff_DR_244 Attachment A-Jackson County Population Interpolation-June 2015 Forecast. The forecasted population values are derived using the population forecasts described next.

Figure 1 describes the forecasting process for population growth:

Figure 1: Forecasting Population Growth



The forecasting models for regional employment growth are

[3] $GEMP_{y,JACK} = \phi_0 + \phi_1 GGDP_{y,US} + \phi_2 GGDP_{y-1,US} + \phi_3 GGDP_{y-2,US} + \omega_{SC} D_{HB,2004-2005=1} + ARIMA\epsilon_{t,y}\,(1,0,0)(0,0,0)_{12}$

JACK is for Jackson County, OR (Medford MSA). $GEMP_y$ is Jackson County employment growth in year y; $GGDP_{y,US}$ is U.S. real GDP growth in year y; and D_{HB} is a dummy for the housing bubble specific to the Medford region. The average GDP forecasts are used in the estimated model to generate five-year employment growth forecasts. The employment forecasts are then averaged with IHS's forecasts (GIHSEMP) for the same county so that:

[4] $F_{Avg}(GEMP_{y,JACK}) = \frac{F(GEMP_{y,JACK}) + F(GIHSEMP_{y,JACK})}{2}$

Averaging reduces the systematic errors of a single-source forecast. Therefore, the average forecast generated by [4] is used to generate the population growth forecasts, which are described next.

The forecasting models for regional population growth are:

[5] $GPOP_{y,JACK} = \psi_0 + \psi_1 GEMP_{y-1,JACK} + \psi_2 GEMP_{y-2,CA} + \omega_{OL} D_{1991=1} + \omega_{SC} D_{HB,2004-2006=1} + \epsilon_{t,y}$

$GPOP_{y,JACK}$ is Jackson County population growth calculated from U.S. Census mid-year estimates; $D_{1991=1}$ is a dummy variables for recession impacts; $GEMP_{y-1,US}$ and $GEMP_{y-2,U.S.}$ are U.S. employment growth in year y-1 and y-2; and CA is California Employment growth in year y-1. Because of its close proximity to CA, CA employment growth is better predictor of Jackson, OR employment growth than U.S. growth. The employment forecasts from [4] are used in [5] to generate population growth forecasts. These forecasts are combined with IHS's forecasts (GIHSPOP) for Jackson, OR in the form of a simple average:

[6] $F_{Avg}(GPOP_{y,JACK}) = \frac{F(GPOP_{y,JACK}) + F(GIHSPOP_{y,JACK})}{2}$

The average forecast generated by [6] is converted to a monthly growth rate and used to forecast population for use in the Medford residential 410 customer forecast. The monthly forecasted growth rate is calculated as $[1 + F_{Avg}(GPOP_{y,JACK})]^{\frac{1}{12}} - 1$ on a June to June basis, starting from the most recent mid-year Census estimate. The annual rates generated by [6] can be found in Staff_DR_244 Attachment B-Regional Indicator Data Base2-June 2015 Forecast by going to the tab "Population Forecast" and starting in cell X-35. This tab has links to the tab "Employment Forecast" which shows the forecasts generated by equation [3], starting in cell W-40. Due to the electronic nature of Attachment B it is being provided in electronic form only.

In order to maximize the available customer data, several months of forecasted population data may be used in regression estimation of the forecasting model. This issue occurs because of differences between the timing of the forecast and the release of the newest population estimates. For example, the 2015 population estimates will not be released until mid-2016; therefore, for the most recent Medford residential 410 customer forecast, forecasted population values for July 2014 through April 2015 were used to estimate the regression equation shown in 244 (b).

(e): See response to (a).

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED: 08/24/2015
CASE NO.:	UG 288	WITNESS: Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER: Grant D. Forsyth
TYPE:	Data Request	DEPT: Financial Planning & Analysis
REQUEST NO.:	Staff – 279	TELEPHONE: (509) 495-2765
		EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. Please explain the following for the Roseburg region:

a. The historical residential customer count and residential use-per-customer data is available from January, 2004 through April, 2015. What statistical tests are performed for selecting the sub-sample from January, 2005 through April, 2015 for forecasting residential customer counts and residential use-per-customer?

   b. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Mar2007, Point: Dec2007, Point: Feb2008, Point: Nov2009, Ramp: Jan2007, Step: Jan2007, Point: Feb2015, Point: Dec2005, Point: Nov2005, and Point: Nov2006 for the residential customer forecast model;

   c. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Feb2012, Point: Mar2011, Point: Dec2006, and Point: Dec2011 for the residential use-per-customer forecast model;

   d. Please explain the parameter coefficients of the two variables ROSHDD and ROSQHDD as shown in SAS parameters.xlsx, included in the file OR ROS Sch 410r UPC; and

   e. Please explain why the company has included the squared weather variables represented as ROSHDD2 and ROSQHDD2, as shown in SAS parameters.xlsx, included in the file OR ROS Sch 410r UPC.

RESPONSE:

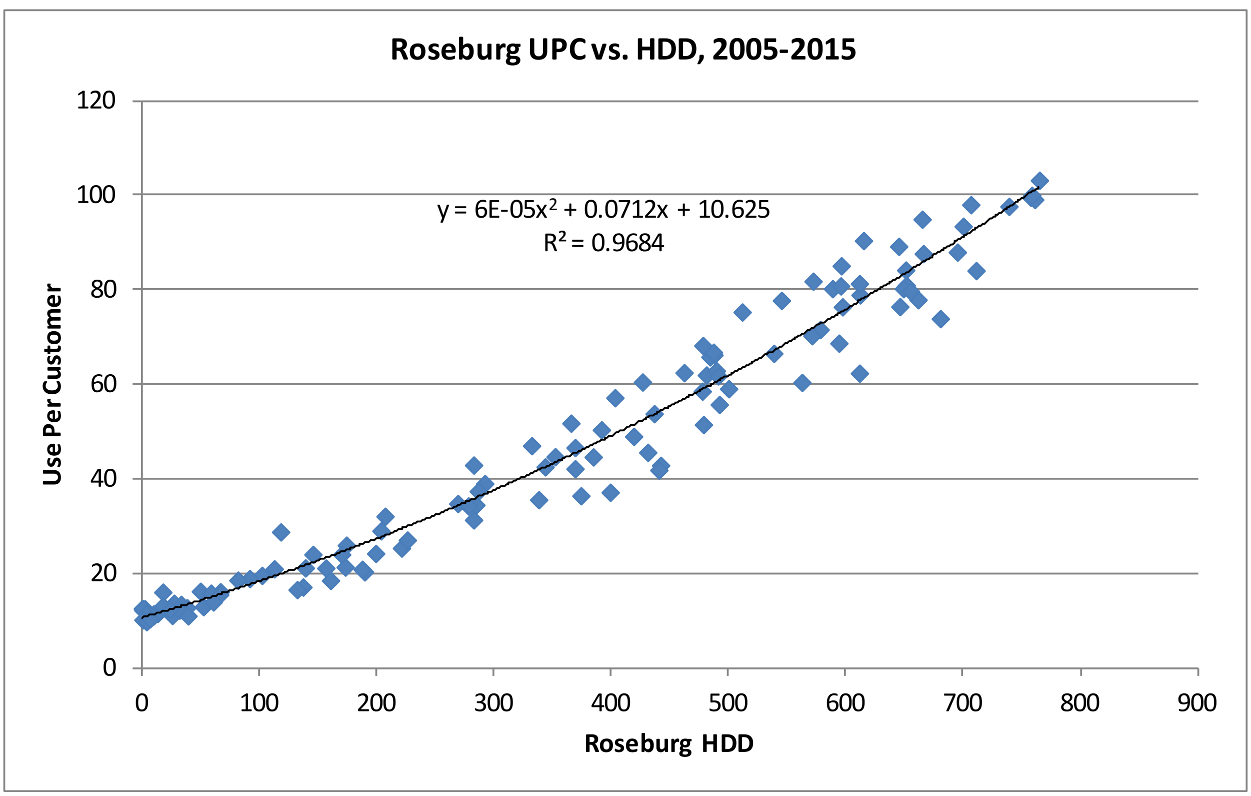
(a): The decision to leave out 2004 was not based on a statistical test. It was left out of the estimation period to provide the option of using 2004 as a lagged dependent variable in the customer regressions. The same applies for the use per customer regressions. This issue was discussed with Staff at the August 17th meeting at the OPUC's offices in Salem, OR.

(b)-(c): The initial identification of potential outliers is done by examining the standardized residuals from the regression model. Next, a dummy is applied to the outlier to determine if applying the dummy alters regression coefficients (1) significantly alters the in-sample RMSE; (2) improves the outcome of white-noise tests; and (3) alters the type of needed error

correction. A significant change in any of these is a sign of influence. In addition to these tests, the error terms of the regression are often imported into SAS/JMP to determine to what extent potential outliers are impacting the assumption of error term normality. This is done by analyzing the normality assumption with and without the potential outliers. The normality test is done using the Shaprio-Wilk test. None of these tests were retained in this forecast. Repeated forecast runs suggest that, as a general rule of thumb, standardized outliers above 2.5 will likely have significant influence. This issue was discussed with Staff at the August 17th meeting at the OPUC's offices in Salem, OR.

The ramping variable is used to adjust for a sharp, structural decline in customer growth created by the collapse of the housing bubbling. That is, there was a sharp decline in the trend in customer growth starting in 2008. Excluding the ramping variable created customer forecasts that were higher than what could be supported with permitting and similar measures of regional economic activity. Including the ramping variable also improved error term behavior and the overall fit of the regression model.

(d)-(e): The weather variables ROSHDD, ROSHDD2, ROSQHDD, and ROSQHDD2 are included because of the non-linear relationship between use per customer and HDD. The graph below shows this relationship for Roseburg schedule 410 residential use per customer and HDD:



Note that the regression line bends up in a non-linear fashion in a way that would not be captured by a linear function incorporating only ROSHDD. The addition of the variables ROSQHDD and ROSQHDD2 control for the steep, non-linear run-up in use-per-customer in December to January/February and the steep run-down in load January/February to March. Approximately 60% of a calendar year's load will occur over these four months. Note that in January and February, the regression coefficients on ROSHDD and ROSQHDD are additive; the same holds for ROSHDD2 and ROSQHDD2.

By way of interpretation, the regression coefficients on ROSHDD, ROSHDD2, ROSQHDD, and ROSQHDD2 can be used to test the sensitivity of use-per-customer to changes in temperature. In addition, they can also be used to weather normalize usage using the difference between the current definition of normal weather HDD and to actual weather HDD over a given year. These issues were discussed with staff at the August 17th meeting at the OPUC's offices in Salem, OR.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED: 08/24/2015
CASE NO.:	UG 288	WITNESS: Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER: Grant D. Forsyth
TYPE:	Data Request	DEPT: Financial Planning & Analysis
REQUEST NO.:	Staff – 280	TELEPHONE: (509) 495-2765
		EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. Please explain the following for the Klamath Falls region:

a. The historical residential customer count and residential use-per-customer data is available from January, 2004 through April, 2015. What statistical tests are performed for selecting the sub-sample from January, 2005 through April, 2015 for forecasting residential customer counts and residential use-per-customer?

b. Please explain and provide any statistical tests performed for selecting intervention variables- Ramp: Jan2007, Point: Feb2015, Step: Jan2007 for the residential customer forecast model;

c. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Feb2011, Point: Dec2008, Point: Nov2009, and Point: Apr2007 for the residential use-per-customer forecast model;

d. Please explain the parameter coefficients of the two variables KLMHDD and KLMQHDD as shown in SAS parameters.xlsx, included in the file OR KLM Sch 410r UPC; and

e. Please explain why the company has included the squared weather variables represented as KLMHDD2 and KLMQHDD2, as shown in SAS parameters.xlsx, included in the file OR KLM Sch 410r UPC.

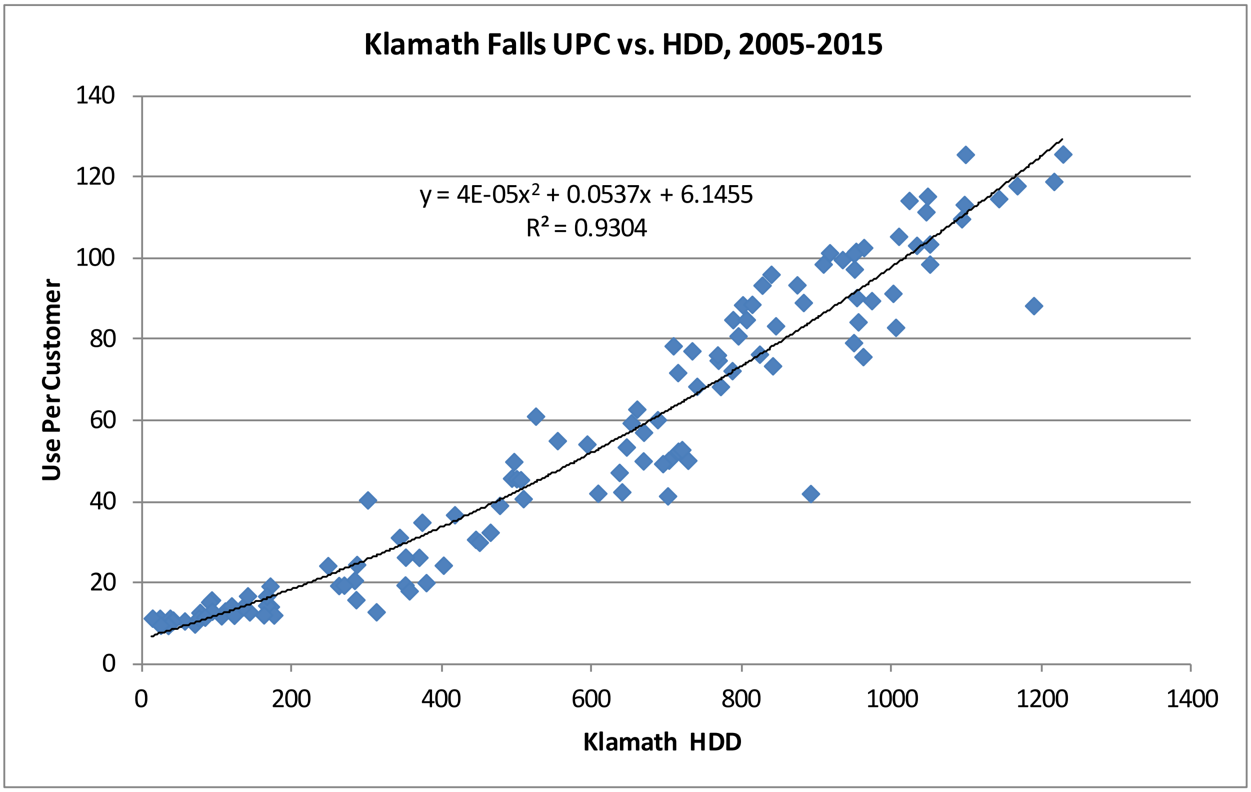
RESPONSE:

(a): The decision to leave out 2004 was not based on a statistical test. It was left out of the estimation period to provide the option of using 2004 as a lagged dependent variable in the customer regressions. The same applies for the use per customer regressions. This issue was discussed with Staff at the August 17th meeting at the OPUC's offices in Salem, OR.

(b)-(c): The initial identification of potential outliers is done by examining the standardized residuals from the regression model. Next, a dummy is applied to the outlier to determine if applying the dummy alters regression coefficients (1) significantly alters the in-sample RMSE; (2) improves the outcome of white-noise tests; and (3) alters the type of needed error correction. A significant change in any of these is a sign of influence. In addition to these tests, the error terms of the regression are often imported into SAS/JMP to determine to what extent potential outliers are impacting the assumption of error term normality. This is done by analyzing the normality assumption with and without the potential outliers. The normality test is done using the Shaprio-Wilk test. None of these tests were retained in this forecast. Repeated forecast runs suggest that, as general rule of thumb, standardized outliers above 2.5 will likely have significant influence. This issue was discussed with Staff at the August 17th meeting at the OPUC's offices in Salem, OR.

The ramping variable is used to adjust for a sharp, structural decline in customer growth created by the collapse of the housing bubbling. That is, there was a sharp decline in the trend in customer growth starting in 2008. Excluding the ramping variable created customer forecasts that were higher than what could be supported with permitting and similar measures of regional economic activity. Including the ramping variable also improved error term behavior and the overall fit of the regression model.

(d)-(e): The weather variables KLMHDD, KLMHDD2, KLMQHDD, and KLMQHDD2 are included because of the non-linear relationship between use per customer and HDD. The graph below shows this relationship for Klamath schedule 410 residential use per customer and HDD:



Note that the regression line bends up in a non-linear fashion in a way that would not be captured by a linear function incorporating only KLMHDD. The addition of the variables KLMQHDD and KLMQHDD2 control for the steep, non-linear run-up in use-per-customer in December to January/February and the steep run-down in load January/February to March. Approximately 60% of a calendar year's load will occur over these four months. Note that in January and February, the regression coefficients on KLMHDD and KLMQHDD are additive; the same holds for KLMHDD2 and KLMQHDD2.

By way of interpretation, the regression coefficients on KLMHDD, KLMHDD2, KLMQHDD, and KLMQHDD2 can be used to test the sensitivity of use-per-customer to changes in temperature. In addition, they can also be used to weather normalize usage using the difference between the current definition of normal weather HDD and to actual weather HDD over a given year. These issues were discussed with staff at the August 17th meeting at the OPUC's offices in Salem, OR.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED: 08/24/2015
CASE NO.:	UG 288	WITNESS: Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER: Grant D. Forsyth
TYPE:	Data Request	DEPT: Financial Planning & Analysis
REQUEST NO.:	Staff – 281	TELEPHONE: (509) 495-2765
		EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Please refer to Staff DR 193 Attachment B - June 2015 OR Gas Model Runs that shows the model specifications and parameter estimates of the forecasting models. Please explain the following for the LaGrande region:

a. The historical residential customer count and residential use-per-customer data is available from January, 2004 through April, 2015. What statistical tests are performed for selecting the sub-sample from January, 2005 through April, 2015 for forecasting residential customer counts and residential use-per-customer?
b. Please explain and provide any statistical tests performed for selecting intervention variables- Ramp: Jan2008, Point: Feb2015, Point: Jul2006, and Point: Dec2009 for the residential customer forecast model;

c. Please explain and provide any statistical tests performed for selecting intervention variables- Point: Mar2014, Point: Jun2011, Point: May2011, Point: Feb2007, and Step: Jan2009 for the residential use-per-customer forecast model;

d. Please explain the parameter coefficients of the two variables LAGHDD and LAGQHDD as shown in SAS parameters.xlsx, included in the file OR LaG Sch 410r UPC; and

e. Please explain why the company has included the squared weather variables represented as LaGHDD2 and LaGQHDD2, as shown in SAS parameters.xlsx, included in the file OR LaG Sch 410r UPC.

RESPONSE:

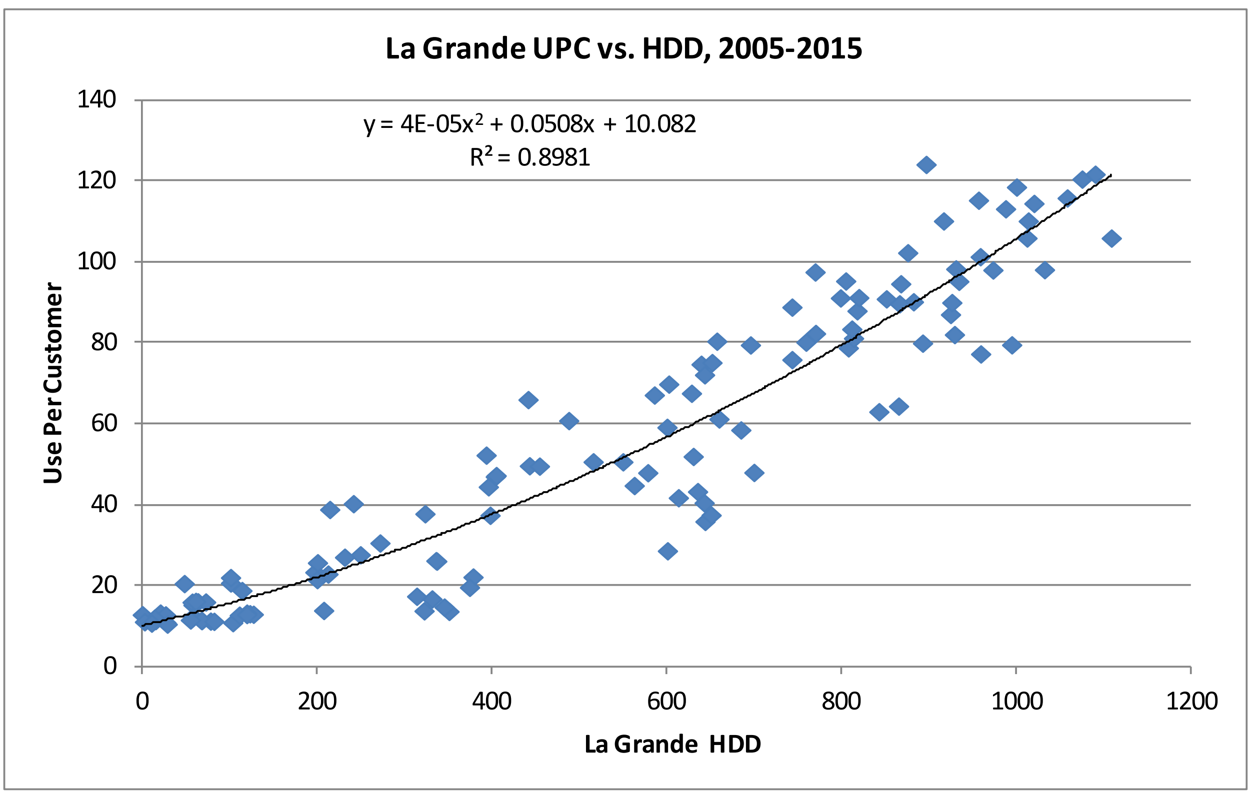
(a): The decision to leave out 2004 was not based on a statistical test. It was left out of the estimation period to provide the option of using 2004 as a lagged dependent variable in the customer regressions. The same applies for the use per customer regressions. This issue was discussed with Staff at the August 17th meeting at the OPUC's offices in Salem, OR.

(b)-(c): The initial identification of potential outliers is done by examining the standardized residuals from the regression model. Next, a dummy is applied to the outlier to determine if applying the dummy alters regression coefficients (1) significantly alters the in-sample RMSE; (2) improves the outcome of white-noise tests; and (3) alters the type of needed error correction. A significant change in any of these is a sign of influence. In addition to these

tests, the error terms of the regression are often imported into SAS/JMP to determine to what extent potential outliers are impacting the assumption of error term normality. This is done by analyzing the normality assumption with and without the potential outliers. The normality test is done using the Shaprio-Wilk test. None of these tests were retained in this forecast. Repeated forecast runs suggest that, as a general rule of thumb, standardized outliers above 2.5 will likely have significant influence. This issue was discussed with Staff at the August 17th meeting at the OPUC's offices in Salem, OR.

The ramping variable is used to adjust for a sharp, structural decline in customer growth created by the collapse of the housing bubbling. That is, there was a sharp decline in the trend in customer growth starting in 2008. Excluding the ramping variable created customer forecasts that were higher than what could be supported with permitting and similar measures of regional economic activity. Including the ramping variable also improved error term behavior and the overall fit of the regression model.

281 (d)-(e): The weather variables LaGHDD, LaGHDD2, LaGQHDD, and LaGQHDD2 are included because of the non-linear relationship between use per customer and HDD. The graph below shows this relationship for La Grande schedule 410 residential use per customer and HDD:



Note that the regression line bends up in a non-linear fashion in a way that would not be captured by a linear function incorporating only LaGHDD. The addition of the variables LaGQHDD and LaGQHDD2 control for the steep, non-linear run-up in use-per-customer in December to January/February and the steep run-down in load January/February to March. Approximately 60% of a calendar year's load will occur over these four months. Note that in January and February, the regression coefficients on LaGHDD and LaGQHDD are additive; the same holds for LaGHDD2 and LaGQHDD2.

By way of interpretation, the regression coefficients on LaGHDD, LaGHDD2, LaGQHDD, and LaGQHDD2 can be used to test the sensitivity of use-per-customer to changes in temperature. In addition, they can also be used to weather normalize usage using the difference between the current definition of normal weather HDD and to actual weather HDD over a given year. These issues were discussed with staff at the August 17th meeting at the OPUC's offices in Salem, OR.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	09/24/2015
CASE NO.:	UG 288	WITNESS:	Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER:	Jeremiah Webster
TYPE:	Data Request	DEPT:	Budget & Forecast
REQUEST NO.:	Staff – 300	TELEPHONE:	(509) 495-2764
		EMAIL:	jeremiah.webster@avistacorp.com

REQUEST:

In response to OPUC DR 243 supplemental in the last rate case UG 284, the Company provided an Excel worksheet (attachment A) showing in detail how load forecasts from SENDOUT as well as forecasts from Grant Forsyth's models were incorporated in the revenue model. Please provide the revised version of this Excel file (with cell formulae intact), applicable for the current rate case UG 288.

RESPONSE:

Please see Staff_DR_300 Attachment A.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION: Oregon DATE PREPARED: 09/25/2015
CASE NO: UG 288 WITNESS: Grant D. Forsyth
REQUESTER: PUC Staff - St. Brown RESPONDER: Grant D. Forsyth
TYPE: Data Request DEPT: Financial Planning & Analysis
REQUEST NO.: Staff – 301 TELEPHONE: (509) 495-2765
EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Please refer to Staff_DR_193 Attachment B - June 2015 OR Gas Model Runs. Please explain why Schedule 410 customer forecast models for Roseburg, LaGrande, and Klamath Falls do not consider April, 2015 actuals for forecasting test year customers.

RESPONSE:

The gas forecast covers three jurisdictions: Washington, Idaho, and Oregon. Due to the time required to finalize the gas forecast, the forecasting process must start well before the June deadline. Therefore, the forecasts for schedules with a relatively small number of customers are run earlier compared to the schedules with relatively large numbers of customers (e.g., schedule 410). As a result, the estimation and forecast period across schedules will differ by a month.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION: Oregon DATE PREPARED: 07/29/2015
CASE NO: UG 288 WITNESS: Grant D. Forsyth
REQUESTER: PUC Staff – Bhattacharya and St. Brown RESPONDER: Grant D. Forsyth
TYPE: Data Request DEPT: Financial Planning & Analysis
REQUEST NO.: Staff – 193 TELEPHONE: (509) 495-2765
EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Please provide a complete data and code documentation of the input/output files used to generate the final dataset for the monthly load forecast described in Avista/700, so that results can be replicated.

a) Source of data;

b) Input/output files for intermediate files and explain what variables are used to merge them into final data; and

c) Input/output files of programs, analysis done in the program and any other comments that are necessary for someone else to run the program.

RESPONSE:

(a): The base data for the most recent customer and use per customer (UPC) forecasts can be found in Staff_DR_193 Attachment A - Gas Data and Forecasts June 2015. The tabs, "WA, ID, OR Residential"; "WA, ID, OR Commercial"; "WA, ID, OR Industrial"; and "WA, ID, OR Sch. 146, 456" contains the monthly billed data for our Oregon, Washington, and Idaho service territories. The tab "Code Book" is a partial description of the schedule titles contained in these four tabs. The customer, use per customer (UPC), and load forecasts for Oregon can be found under the tab "OR June 2015 Forecasts".

(b): Data collated for the SAS/ETS forecasting software. This tab contains schedule customer counts, use per customer values, and all regression variables related to weather, population, price, and U.S. Industrial production.

(c): The forecast regressions for each schedule were estimated using the SAS/ETS forecasting system, which does require the user to write code. It is an interactive system based user defined characteristics. For each schedule regression, four Excel output files were retained: SAS Forecast; SAS Parameters; SAS Fit Tests; and SAS Error Tests. Since most schedules require a customer and UPC there are typically eight output files per schedule. In some cases, a regression model is not used to forecast either customers or UPC; in these cases, there is only one set of four output files. The content of each of these four output files are as follows:

Output File	Output File Contents
SAS Forecast	The base data used to generate the forecast; the forecasts; and error terms.
SAS Parameters	The estimated parameters in the model, including tests of parameter significance.
SAS Fit Tests	A selection of standard fit tests generated by SAS
SAS Error Tests	Autocorrelation functions, tests for white noise, and the Augmented Dickey-Fuller (ADF) stationarity test.

All output files can be found in the file folder "Staff_DR_193 Attachment B - June 2015 OR Gas Model Runs". This file contains subfolders for each schedule requiring a SAS regression. For example, the subfolder "OR MED Sch 410r Cus" contains the output files for Medford's schedule 410 residential customers; likewise, "OR MED Sch 410r UPC" contains the output files for Medford's schedule 410 residential UPC. The same basic labeling is used for the other regions and the related schedules. To emphasize again, not all schedule forecasts need a regression (e.g., some are based on simple moving averages), which means some schedules may only have an output folder for customers or UPC.

Due to the size of the Attachments they are being provided in electronic form only.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED: 08/12/2015
CASE NO.:	UG 288	WITNESS: Grant D. Forsyth
REQUESTER:	PUC Staff – Bhattacharya	RESPONDER: Grant D. Forsyth
TYPE:	Data Request	DEPT: Financial Planning & Analysis
REQUEST NO.:	Staff – 243	TELEPHONE: (509) 495-2765
		EMAIL: grant.forsyth@avistacorp.com

REQUEST:

Avista/700, Forsyth/11-12 report that the Company used 20-year moving average for defining normal weather over the forecast period.

a. Please explain in detail the methodology used for calculating the normal weather for the test year period;

b. For illustrative purpose, please explain how you derived January 2016 normal heating degree days (HDDs) and normal cooling degree days (CDDs) for the Medford region. Provide all associated worksheets (with cell formulae intact) in support of your explanation; and

c. Lines 7-8 of Avista/700, Forsyth/12 state that 10- and 15- year moving averages showed considerably more year-to-year volatility than the 20-year average. Please explain all the necessary steps performed to identify the yearly fluctuations with 10, 15, and 20 year moving averages

RESPONSE:

(a)-(b): Please refer to Staff_DR_243 Attachment A - HDD and CDD Weather Data. By way of example, open the Excel file and go to tab “Medford, OR HDD Data” and go to cell S-99. This shows the 20-year moving average value for January for the 1995-2014 period using Avista’s billing adjusted HDD. This is the current 20-year period that defines normal weather. The remaining months are calculated in a similar fashion. The same calculation is done for the other city regions under the tabs, “Roseburg, OR HDD Data”; “Klamath Falls, OR HDD Data”; and “La Grande, OR HDD Data.” Due to the electronic nature of the attachment it is being provided in electronic form only.

(c): Please refer to Staff_DR_243 Attachment A - HDD and CDD Weather Data. By way of example, go to the tab “Medford Moving Average Analysis” and go to cell D-32. This cell shows the 30-year moving average of HDD for the period of 1948-1977. Under the current moving average methodology, this would have been (theoretically) the period defining normal weather for a load forecast starting in 1978. This approach is repeated for moving average periods of 25, 20, 15, 10, and 5 years. For each of these moving average periods, the standard deviation of the moving average is calculated and plotted against the period of the moving average in the graph “Relationship Between Moving Average Period and Moving Average Standard Deviation." Note that, depending on the region, the standard deviation of the moving average tends to escalate rapidly when the moving average falls below 15 to 20 years. This can be seen by the behavior of the dotted trend line. This is also the case for the three other city regions.

CASE: UG 288
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Cost Allocations

Opening Testimony

October 16, 2015

CERTAIN INFORMATION CONTAINED IN

STAFF EXHIBIT 1100

PAGES 4 , 5, 8 AND 9

ARE CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN DOCKET NO. UG 288.

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

A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Economist in the Energy Resources and Planning Division. My business address is 201 High St. SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Staff's review of Avista Corporation's (Avista or Company) cost allocations.

In conducting the aforementioned review, Staff referred to the Company's initial filing and approximately 14 initial and follow-up data requests (DRs).

Q. Did you prepare exhibits for this docket other than your witness qualification statement?

A. Yes. I prepared Exhibit Staff/1102, consisting of 43 pages (non-confidential responses including attachments to Staff DR 133, 239, 240, 283, 286, 287 and certain portions of Avista's 10-k reports filed with the Securities and Exchange Commission) and Confidential Exhibit Staff/1103, consisting of 1 page (page 5 of confidential Attachment A to the Company's response to Staff DR 286).

SUMMARY RECOMMENDATION

Q. What is Staff's recommendation or conclusion?

A. Staff concludes that, with one exception, Avista's cost allocations are reasonable. The one exception concerns the test year salary amounts assigned to utility operations (Utility Operations) by certain executives of the Company. With regard to this exception, Staff recommends a reduction of these executives' salaries assigned to Utility Operations by $104,000 on a system wide basis, which represent approximately $9,000 on an Oregon-allocated basis. Staff reserves its right to address additional issues that the intervening parties may raise about cost allocations in their respective opening testimonies.

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Description of Staff's Analysis; and
2. Conclusion.

1. DESCRIPTION OF STAFF'S ANALYSIS

Q. Please explain how the Company allocates costs.

A. The Company allocates common revenues, expenses, and rate base between its services (i.e. electric and gas) and its jurisdictions (i.e. Washington, Oregon, and Idaho).

Q. Are there any allocation factors used by the Company to allocate costs?

A. Yes. In the Company's work papers,[1] the Company illustrated the following allocation factors:

[1] See the Company's work paper MS Excel file "2) 2015-Allocation Factors-4 (E&G), 7,8,9-2014 Data," worksheet "NewMemo".

Table 1
(in %)

Service	Description	Electric	Gas	Gas - Oregon
CD	No. of Customers	52.892	33.079	14.029
CD	Net Direct Plant	78.637	14.060	7.303
CD	Four Factor	71.547	19.751	8.702
GD	No. of Customers		70.219	29.781
GD	Four Factor		69.082	30.918

"CD" and "AA" stand for "common to all divisions" and "common to gas divisions" respectively, as described in the Company response to Staff DR 133, included to this testimony as Exhibit Staff/1102, Ordonez/1-3.

Q. Did Staff review the correctness of the above percentage values?

A. Yes. Staff reviewed the estimation of the above percentage values and determined they are correct.

Q. You described the allocation factors used to allocate common costs. Are there any costs that are directly assigned to utility and non-utility operations?

A. Yes. As described in Attachment A of the Company's response to Staff DR 133, included as Exhibit Staff/1102, Ordonez/4-31, the Company directly assigns certain costs to Utility Operations and non-utility operations (Non-Utility Operations or unregulated subsidiaries). Staff's analysis focused on the level of costs that are directly assigned to Non-Utility Operations by its highest paid executives and officers[2].

[2] Staff understands that the definition of the Company of "officers" and "executives" might be different, however for the purpose of this testimony Staff refers to both terms as "executives".

Q. Please describe Staff analysis regarding the cost of Avista's executives that are directly assigned to the Company's Non-Utility Operations

A. Staff chose the five executives whose total compensations were the highest in calendar year 2014 from the confidential attachments to the Company's response to Staff DR 239. The body of the Company's response to Staff DR 239 is included as Exhibit Staff/1102, Ordonez/32. Confidential Table 2 provides information about the compensation received by those executives for years 2012 through 2014 broken down into compensation assigned to Non-Utility Operation and Utility Operations. Confidential Table 3 expresses the same information in percentage values.

Table 2
Total Compensation of Selected Executives
($)

#	Executive	Non-Utility Operations			Utility Operations		
		2012	2013	2014	2012	2013	2014
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3
Total Compensation of Selected Executives
(%)

#	Executive	Non-Utility Operations			Utility Operations		
		2012	2013	2014	2012	2013	2014
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Averages by year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Averages by Operations	[redacted]			[redacted]		

Q. Did Staff contrast the percentage information provided in Table 3 with an amount that represents the share of the Company's Non-Utility Operation from the Company as a whole?

A. Yes. Staff reviewed the magnitude of Non-Utility Operations' plant (Property, Plant and Equipment) and revenues (Operating Revenue) relative to the Company as a whole. By the Company as a whole, Staff means the combined Non-Utility Operations and Utility Operations. From the Company's 2014 and 2013 10-k reports filed with the Securities and Exchange Commission, included as Exhibit Staff/1102, Ordonez/33-36, Staff built the Tables 4 and 5 shown below:

Table 4
Financial Information for Non-Utility Operations, Utility Operations, and Total Corporation
($)

#	Type of Financial Information	Non-Utility Operations			Utility Operations		
		2012	2013	2014	2012	2013	2014
1	Property, Plant and Equipment	52,828	51,997	221,155	4,197,742	4,450,787	4,750,468
2	Operating Revenue	38,953	39,549	39,219	1,352,385	1,402,195	1,433,343

Table 5
Financial Information for Non-Utility Operations, Utility Operations, and Total Corporation
(%)

#	Type of Financial Information	Non-Utility Operations			Utility Operations		
		2012	2013	2014	2012	2013	2014
1	Property, Plant and Equipment	1%	1%	4%	99%	99%	96%
2	Operating Revenue	3%	3%	3%	97%	97%	97%
	Averages by year	2%	2%	4%	98%	98%	96%
	Averages by Operations	3%			97%		

Q. Please continue explaining Staff's analysis

A. As shown in Table 5, the Company's Non-Utility Operations represent approximately three percent relative to the Company as a whole for the most recent three calendar year period (2012-2014).

As shown by Table 3, with exception of one executive, all of the executives' compensation assigned to Non-Utility Operations exceeds the three percent figure with the exception of one executive.

Q. Why does this one executive you identified not directly assign more costs to the Non-Utility Operations of the Company?

A. In Staff DR 287, Staff requested the Company to provide the title, duties and responsibilities of this executive. The body of the Company's response to Staff DR 287 is included in this testimony as Exhibit Staff/1102, Ordonez/37.

In Avista's response to this data request, the Company represented that the title of this executive is President of Avista Utilities.[3] Additionally, the Company provided the job description of this executive in confidential Attachment A to the Company's response to Staff DR 286, included as Confidential Exhibit Staff/1103, Ordonez/1. From the information provided by the Company and after reviewing the title and job description of this executive, Staff determines that due to this executive's title and duties and responsibilities, which are mostly related to the Company's Utility Operations, it is reasonable for this executive to directly assign a greater level of costs to Utility Operations.

[3] The Company identified the title of this executive in its non-confidential response to Staff DR 287, I.

Q. Did Staff corroborate its assessment that the highest paid executives' levels of costs assigned to Non-Utility Operations are reasonable?

A. Yes. Staff corroborated its conclusion in two ways.

Q. Please explain the first verification method Staff used.

A. In the Company's response to part "a" of Staff DR 240, included as Exhibit Staff/1102, Ordonez/38-40, the Company represented that "the Company does maintain a timekeeping system within which each individual employee enters his/her time by day, by project (includes FERC accounts) for a two week period.…This information is then reviewed and approved bi-weekly by the individual's supervisor to [ensure] accuracy in project selection. The timekeeping system gathers this information, summarizes it into monthly amounts, and feeds it to the general ledger in order to query for reporting purposes… Finally, the Company's third-party independent auditor Deloitte and Touche annually audits the timekeeping system from timekeeping entry to general ledger and reporting to actual payroll."[4]

Per the Company's response, Staff concluded that the Company has appropriate timekeeping controls.

Q. Please explain Staff's second verification method

A. Staff reviewed the involvement of these executives in Non-Utility Operations thorough the Board of Directors meetings and the respective meetings' minutes from 2012 through 2014. This was provided by the Company after Staff followed-up on Staff DR 286 (the body of the Company's initial response is

[4] See the Company's response to part "a" of the Company's response to Staff DR 240 at Exhibit Staff/1102, Ordonez/35, included with this testimony.

included as Exhibit Staff/1102, Ordonez/41-43.) Staff found that these five executive were present in almost all the Board of Directors meetings. Staff also built Table 6 and 7 below.

Q. Please explain your Tables 6 and 7.

A. Table 6 provides the number of issues covered in the Board of Directors meetings by year broken down into Non-Utility and Utility related issues. Table 7 expresses the same information in percentage values. From Table 7, the number of Non-Utility Operations' issues covered in the Board of Directors meetings represent approximately [redacted] percent relative to the total number of issues covered for the most recent three calendar year period (2012-2014). This percentage is close to the approximately [redacted] percent of the five executives compensation assigned to Non-Utility operations in the most recent three calendar year period (2012-2014).

Table 6
Number of Issues Covered in Board of Directors Meetings

	Non-Utility Operations Related Issues			Utility Operations Related Issues		
	2012	2013	2014	2012	2013	2014
By Year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
By Operations		[redacted]			[redacted]	

Table 7
Number of Issues Covered in Board of Directors Meetings
(%)

	Non-Utility Operations Related Issues			Utility Operations Related Issues		
	2012	2013	2014	2012	2013	2014
By Year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
By Operations		[redacted]			[redacted]	

Q. In your summary recommendation you identified one “exception” associated with the test year salary amounts assigned to Utility Operations. Please elaborate on that issue.

A. Yes. As shown by Table 8 below, the amounts of total compensation represented by the percentage assigned to Utility Operations in the past three years (i.e., 2012 through 2014) in aggregate differ with the *pro forma* (test year) percentages proposed by the Company.

Table 8
Assignation of Cost to Utility Operations
(%)

#	Executive	Utility Operations	
		Historical[5] Average 2012-2014	Company-proposed Test Year[6]
1	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]
Average		[redacted]	[redacted]

Applying the historical percentages to the salary compensation of these executives for the test year salaries presented in workpaper workbook "2) 2015 OR Executive Officer Pro-Forma Labor.xlsx," worksheet "Pro-Forma Labor Total," column “Z” instead of the Company-proposed test year information results in a reduction of these executives’ salaries assigned to Utility

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[5] Source: Table 3 of this testimony.
[6] Source: workpaper workbook "2) 2015 OR Executive Officer Pro-Forma Labor.xlsx," worksheet "Pro-Forma Labor Total," column “K”.

Operations of approximately $104,000 on a system wide basis, which represents approximately $9,000[7] on an Oregon-allocated basis.[8]

2. CONCLUSION

Q. What is Staff's conclusion?

A. Based upon the Company's filing including workpapers, initial and follow-up DRs, and Staff analysis, Staff concludes that, with one exception, Avista's cost allocations are reasonable. The one exception concerns the test year salary amounts assigned to Utility Operations by certain executives of the Company. With regard to this exception, Staff recommends a reduction of these executives' salaries assigned to Utility Operations by $104,000 on a system wide basis, which represent approximately $9,000 on an Oregon-allocated basis.

Q. Would you like to address any other matters?

A. Staff anticipates that other parties to this docket may raise issues related to cost allocations. Staff reserves the opportunity to address these issues and any additional issues or adjustments presented by an intervening party.

Q. Does this conclude your testimony?

A. Yes.

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[7] The allocation factor used by Staff to express the system-wide figure into an Oregon-allocated figure is the four factor allocation factor of 8.702 percent for common costs presented in Table 3 of this testimony.

[8] For details of Staff's adjustment, please see confidential workpaper workbook "CONFIDENTIAL workpapers," worksheet "adjustment".

CASE: UG 288
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Economist Energy Resources and Planning Division
ADDRESS	201 High Street SE., Suite 100 Salem OR 97301
EDUCATION AND TRAINING	Utility Management Certificate Willamette University, Oregon, 2008
	Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency, Sweden, 2006 & South Africa, 2007
	Fulbright Scholar, MBA, concentration in finance Willamette University, Oregon, 2005
	Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002
	BS, Mechanical Engineering, thermal power efficiency Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998
EXPERIENCE	I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist, evaluating utilities' issuance of securities, cost of capital, mergers and acquisitions, cost of service studies, marginal cost studies, rate spread and rate design, integrated resource plans, purchased natural gas costs, and power costs.

CASE: UG 288
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support
Of Opening Testimony

October 16, 2015

c. For <u>each</u> account under the Column "A" of worksheet "AF-01" in workpaper MS Excel file "1) 2014 Allocation Factor Adj," please provide a detailed explanation of the rationale by which the such allocation factor under Column "X" was used;[1]
d. Regarding MS Excel rows "13" and "14" (both named "Taxes Other Than Inc – Storage"), where the Company used a 19.10 percent updated allocation factor, please:
    i. Explain why the 19.10 percent number is not shown in the table above;
    ii. Provide a detailed explanation of how the 19.10 percent number was calculated; please provide the Company's workpapers in electronic spreadsheet formulae with cell references and formulae intact;
    iii. Should the acronym "WA" under column "Ser" for rows "13" and "14" mean the Washington Jurisdiction, please provide a comprehensive explanation of why the Oregon Jurisdiction might being allocated costs related to the Washington Jurisdiction; and
    iv. Provide a detailed explanation of the rationale by which the 19.10 percent figure was used and why not any of the other allocation factors referred in the above table was used (i.e., 14.029 percent 7.303 percent, 8.702 percent, 29.781 percent, 30.918 percent).

If the information requested in the above questions, including any component or subcomponent, was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

RESPONSE:

a) The Company converted to the Oracle Financial System on January 1, 2005. With the implementation of the Oracle Financial System, the two-digit alpha codes for service and jurisdiction were adopted. The two-digit alpha codes are described in the Company's response Staff_DR_132. The allocation methodology did not change with the implementation of the Oracle Financial System, but only the account code labeling was changed. Prior to converting financial systems, the Company used a single-digit utility code to identify operating divisions. The Company used the following utility codes (with the new alpha codes identified in parenthesis):

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[1] For example, regarding row "5," (Depreciation Expense) of the MS Excel file "1) 2014 Allocation Factor Adj," worksheet "AF-01," where the Company used an updated allocation factor of 30.918 percent, please provide a comprehensive explanation of the rationale by which the 30.918 percent figure was used and why not any of the other allocation factor referred in the above table (i.e., 14.029 percent 7.303 percent, 8.702 percent, and 29.781 percent) was used.
Another example, regarding row "6," (Depreciation Expense) of the MS Excel file "1) 2014 Allocation Factor Adj," worksheet "AF-01," where the Company used an updated allocation factor of 100 percent, please provide a comprehensive explanation of the rationale by which the 100 percent figure was used and why not any of the other allocation factor referred in the above table (i.e., 14.029 percent 7.303 percent, 8.702 percent, and 29.781 percent) was used.
Please perform the same analysis for each account under Column "A" of worksheet "AF-01" in workpaper MS Excel file "1) 2014 Allocation Factor Adj," as requested in part "c" of this data request.

0 –Electric division (ED ID, ED WA, ED AN)
1 – WA/ID Gas division (GD ID, GD WA, GD AN)
2 –OR Gas division (GD OR)
7 – Common to all divisions (CD AA)
8 – Common to only Gas divisions (GD AA)
9 – Common to WA/ID Electric and Gas divisions (CD ID, CD WA, CD AN)

When the Company converted financial systems in 2005, many Avista employees and Staff at the state utility Commissions were comfortable with the old utility codes, so the memo was updated to include the "new" service and jurisdiction codes with the "old" utility codes. The Company converted systems over 10 years ago, however, the utility codes are still used to refer to the allocation factors, so the information has not been removed from the memo.

b & c) Please see Staff_DR_133-Attachment A. This is an excerpt from testimony provided by Company witness Liz Andrews in Avista's 2014 Washington GRC (Docket Nos. UE-140188 and UD-140189). It describes all of the allocation methodology used by the Company for both electric and natural gas.

d) The Jackson Prairie Natural Gas Storage Facility is located in Washington. The Company pays property taxes on the facility to Washington State. A portion of the facility is allocated for the benefit of Oregon customers. The Company uses the net book value of the property to allocate the property tax costs between Oregon and Washington/Idaho (AN) customers. Please see Staff_DR_133-Attachment B for the computation of the factor used in "1) 2014 Allocation Factor Adj".

The service and jurisdiction are assigned to property taxes (expense FERC Accounts 408150, 408170, 408180, and 408190 and the liability FERC Account 236100) differently than the rest of the FERC accounts at Avista. For FERC accounts that are not property taxes, the jurisdiction assigned represents the jurisdiction that will be allocated the expense. For property taxes, the jurisdiction assigned represents the state where the tax is incurred and not where the tax will be expensed. In other words, the jurisdiction for property tax FERC accounts represents that taxes paid on the property that is located in that state. The Company allocates the property tax expense to the jurisdictions using specific FERC subaccounts. Because the tax on the Jackson Prairie Natural Gas Storage Facility is paid to Washington, it is assigned GD.WA. But, as described above, it is appropriate to allocate a portion of those costs to Oregon.

The Company has completed such audits for the periods 2010 through 2012, with each of these reports provided to all parties.[48] The Company provided a copy of its last report, the 2012 Accounting Practices Audit, to all parties on May 20, 2013. The cost of the 2012 audit was approximately $49,000 in internal labor and benefit costs. The 2013 Accounting Practices Audit report is scheduled to be complete in May 2014, at which time the report and the costs will be provided to all parties.

<u>Tracking of Aldyl-A Natural Gas Pipeline Replacement Program Projects</u>

Q. Order No. 9, approving the Settlement Stipulation in Docket Nos. UE-120436 and UG-120437, required Avista to begin tracking separately, on January 1, 2013, all projects associated with its Aldyl-A natural gas pipeline replacement program. Has the Company fulfilled these requirements?

A. Yes. Beginning January 1, 2013 the Company began tracking through separate projects its Aldyl-A natural gas pipeline replacement program projects and will make this information available upon request to the Commission.

<u>Cost Assignment & Allocation Methodologies</u>

Q. Order No. 9, approving the Settlement Stipulation in Docket Nos. UE-120436 and UG-120437, required Avista to provide additional information regarding its cost[49] assignment and allocation methodologies in its next general rate

[48] The Company provided its 2010 Accounting Practices Audit report and costs within its 2011 GRC filing in Docket Nos. UE-110876 and UG-110877. (See Exhibits Nos. __(EMA-1T) and __(EMA-5).) The Company provided its 2011 Accounting Practices Audit report and costs within its 2012 GRC filing in Docket Nos. UE-120436 and UG-120437. (See Exhibits Nos. __(EMA-1T) and __(EMA-4).)

[49] The Company records revenues, expenses and net plant investment in common accounts that must be allocated to services and jurisdictions. The same allocation process and methodologies are used for all of these accounts. The Company will refer to these revenues, expenses and net plant investment as "costs" throughout this document.

case. Has the Company fulfilled these requirements?

A. Yes. In Paragraph 17 of the Multiparty Settlement Stipulation in Dockets UE-120436 and UG-120437, the settling parties agreed that Avista, in its next general rate case, would provide justification for the service and jurisdictional cost allocation methodologies that it employs. The Company met with several members of the WUTC Staff on December 2, 2013, to provide an overview of Avista's operations and accounting practices, including an overview of its allocation processes and methodologies. The allocation presentation used by the Company at this meeting is provided as Exhibit No. ___ (EMA-7). The testimony that follows describes Avista's cost allocation procedures and why we believe the method used by Avista produces a reasonable allocation of costs.

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[50]: Washington (WA) and Idaho (ID), and natural gas service in three retail jurisdictions: Washington, Idaho and Oregon (OR).

Retail natural gas service provided in eastern Washington and northern Idaho is accounted for separately as the WA/ID natural gas service, or as the North natural gas service. Natural gas service in central and southwest Oregon and is accounted for separately as our Oregon jurisdiction, or the South natural gas service.

Q. How does the Company assign costs by service and jurisdiction?

[50] Avista serves approximately 25 retail electric customers in Montana.

A. Whenever possible, the Company directly assigns its revenues, operating costs and net plant investment to services and jurisdictions. For costs not directly assigned, the Company uses an allocation process using allocation factors that are derived from directly assigned costs which are updated annually. The costs that are not directly assigned are referred to as "common" costs.

For example, Avista's main headquarters in Spokane supports all services and jurisdictions, therefore the operating costs, depreciation expense and net book value of the building is allocated to all services and jurisdictions using allocation factors.

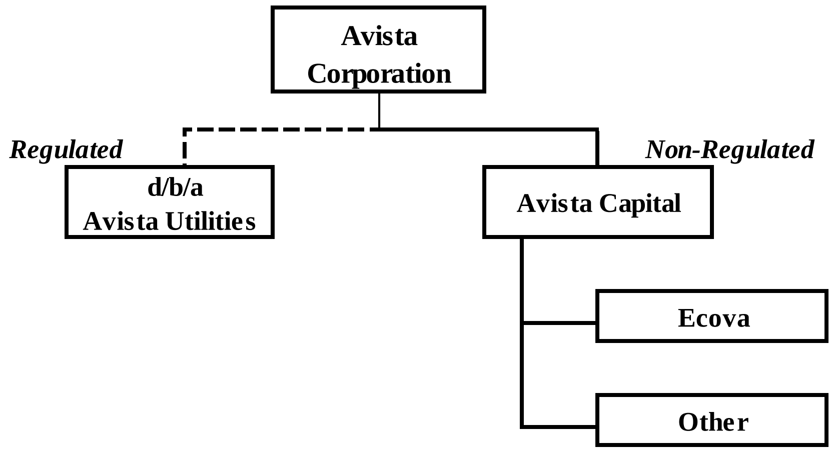
Q. Please explain how the Company accounts for these "common" costs that must be allocated.

A. The Company uses service codes (electric, natural gas and common) and jurisdiction codes (state and common) on all accounting transactions to indicate where costs should be recorded (either directly assigned or where a common cost should be allocated). Both service codes and jurisdiction codes consist of two-digit alpha codes, described further below. The assignments and allocations are used for internal, financial and regulatory reporting and for ratemaking purposes.

Q. Are costs also allocated to non-utility operations or subsidiary companies of Avista Corp.?

A. Instead of being allocated, certain costs are directly assigned to non-utility operations or subsidiaries. Avista Utilities is the regulated operating division of Avista Corp. A current organization chart for Avista Corp. is provided in Illustration No. 3 below.

Illustration No. 3



Certain officers and general office employees of Avista 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, there is no need to allocate costs to subsidiaries or non-utility accounts as part of the allocation procedures described below, because they are all directly assigned.

An example of the Company's process for recording subsidiary-related costs is provided in Table No. 2 below.

Table No. 2

Detail of Directors' Fees For Twelve Months Ended June 30, 2013 ($000's)		
Total Directors' Fees		$ 1,531
Less: Subsidiary Directors' Fees Charged to FERC 417/186		44
Avista Corp. Directors' Fees		1,488
Less: 10% Charged to Non-utility (FERC 417)		148
Utility Directors' Fees - System		$ 1,340
Allocation of Utility Directors' Fees by Service Using Factor 7:		
Electric	72.346%	$ 969
Natural Gas North	19.401%	260
Natural Gas South (Oregon)	8.253%	111
Total	100.000%	$ 1,340
Allocation of ELECTRIC Utility Directors' Fees by Jurisdiction Using Factor 4:		
Washington Electric	67.000%	$ 649
Idaho Electric	33.000%	320
Total	100.000%	$ 969
Allocation of NATURAL GAS NORTH Utility Directors' Fees by Jurisdiction Using Factor 4:		
Washington Natural Gas	70.603%	$ 184
Idaho Natural Gas	29.397%	76
Total	100.000%	$ 260

Table No. 2 shows that a total of $1.53 million of directors' fees was paid during the twelve months ended June 30, 2013. Of this amount, $44,000 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 $1.53 million of Avista Corp. Board of Director Fees, $148,000 was directly charged to a non-utility FERC account related to subsidiary operations.[51] The remaining $1.34 million that was charged to the utility is allocated by service and jurisdiction.

Q. Do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. When the Company designed the allocation methodology that is being used today, the specific objectives identified were as follows:

a) The method must be acceptable to all regulators to prevent any stranded costs or investment,

b) The number of cost allocation methods should be minimized,

c) The method needs to be simple,

d) The method needs to have a sound, rational basis,

e) Allocations under the method should be automated, and

f) The method needs to produce reasonable results.

These objectives are still relevant today. The Company believes the methodology continues to meet these over-all objectives.

The over-all 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 by service and jurisdiction. The method ultimately proposed by Avista and approved by the state Commissions (Washington, Idaho, and Oregon) produced a reasonable allocation of common costs.

[51] 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. Please explain when the Company began using the current methodology.

A. The current method used for electric generation and transmission expenses and net plant investment was reviewed and supported by the Washington and Idaho Commission staffs in 1984. This methodology uses the production/transmission ratio for electric expense FERC Accounts 500 through 573, which is described further below.

The current method for all other expenses (expense FERC Accounts 580 through 935) and net plant investment (i.e. excluding electric generation and transmission expenses and net plant investment), was developed and presented to the Commission staffs of Washington, Idaho and Oregon 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. This allocation methodology and the actual allocation of common 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.

Q. When did the Company begin using the current service and jurisdiction codes?

A. The Company converted to the Oracle Financial System on January 1, 2005. With the implementation of the Oracle Financial System, the two-digit alpha codes for service and jurisdiction were adopted. The allocation methodology did not change with the implementation of the Oracle Financial System, but only the account code labeling was changed.

Q. Would you please identify the service codes that are used?

A. Yes. The Company uses the following service codes:

ED – Electric Direct
GD – Gas Direct
CD – Common Direct
ZZ – No Service (Used for balance sheet accounts (FERC Accounts 100-399) that are not assigned to a service (i.e. cash, accounts payable, etc.) and non-utility accounts)

Q. Would you please identify the jurisdiction codes that are used?

A. Yes. The Company uses the following jurisdiction codes:

AA – Allocated All
AN – Allocated North
ID – Idaho
MT – Montana
OR – Oregon
WA – Washington
ZZ – No Jurisdiction (Used for balance sheet accounts (FERC Accounts 100-399) that are not assigned to a jurisdiction (i.e. cash, accounts payable, etc.) and non-utility accounts)

Q. Would you please summarize the assignment and utility code/allocation method currently in use for costs?

A. Yes. To begin with, revenues, operating costs and plant are directly assigned to services and jurisdictions whenever possible.

As explained earlier, for those costs not directly assigned, the costs are allocated using a variety of allocation factors. The Company annually computes the allocation factors using actual direct costs and other data points (i.e. customer counts, customer usage, etc.). Updating the factors with current data on an annual basis is appropriate so that 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.

Q. Would you describe the various types of allocation factors used by the Company?

A. Yes. The Company uses primarily three different types of allocation factors, including:

a) Allocation factors that are used to allocate common costs and 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.

b) Allocation factors that use one data point (i.e. customer count or directly assigned distribution costs, etc.)

c) Allocation factors specific to electric costs or natural gas costs. These factors are the Production/Transmission (P/T) ratio for electric service and the System Contract Demand ratio for natural gas service, which are described below.

Allocation Factors

Allocation of Electric Production and Transmission Costs and Plant

Q. Would you please summarize the P/T ratio computation that is currently used to allocate electric generation and transmission costs and plant between Washington and Idaho?

A. Yes. The Company annually computes an allocation factor, called the P/T ratio (production/transmission ratio) using the previous year's actual usage amounts for retail customer demand and energy consumption. The kilowatt demand figures are the coincident contributions of each jurisdiction to the Company's monthly system peak loads. The kilowatt-hour energy consumption represents the actual sales figures. Both demand and energy use ratios are weighted equally in arriving at the allocation factor. This is Factor 1 for electric service.

Allocation of Natural Gas Underground Storage Costs and Plant

Q. Would you please summarize the System Contract Demand ratio computation that is currently used to allocate natural gas underground storage costs and plant?

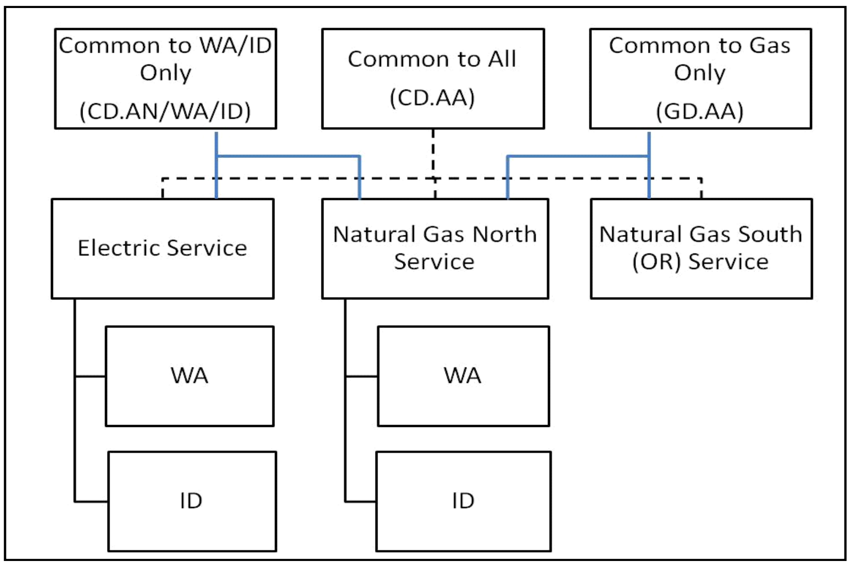
A. Yes. The Company annually computes the System Contract Demand allocation factor (also known as the five-day peak factor) using the actual therm throughput during the five consecutive days in the year with the highest throughput. The actual throughput for Washington and Idaho for this five-day period is averaged over three years, to determine the allocation of costs between Washington and Idaho. The Company directly assigns the O&M costs (FERC Account Nos. 824 and 837) of its share of the Jackson Prairie storage facility to Oregon and Natural Gas North Service, using the proportionate share of capacity assigned to each. Therefore, no further allocation of these costs to Oregon is required. This is Factor 1 for natural gas service.

<u>Allocation of Common Costs</u>

Q. Would you describe the allocation process used by the Company to allocate common costs?

A. Yes. Illustration No. 4 below depicts the allocation of common costs.

<u>Illustration No. 4</u>



The allocation of common costs is a two-step process. The first step is to allocate the common costs to one of the three <u>services</u>: Electric, Natural Gas North or Natural Gas South.

Three different 4-factors are used to allocate the common costs to the three services. These 4-factors are used to allocate all common costs recorded in all FERC Accounts, except FERC Accounts 901-905 (Customer Accounts Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and FERC Accounts 911-917 (Sales Expenses). These costs in FERC Accounts 901 through 917 are heavily influenced by the number of customers, and therefore, it is more appropriate to allocate these common costs using the number of customers.

The three 4-factors that are used to allocated common costs to services follows:

- Factor 7 (CD.AA) – Factor used to allocate common costs to all services, including Electric, Natural Gas North and Natural Gas South. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to electric service, natural gas North service and natural gas South service.
  (2) Direct O&M and A&G labor that are assigned to electric service, natural gas North service and natural gas South service.
  (3) Number of customers for electric service, natural gas North service and natural gas South service.
  (4) Net direct plant that is assigned to electric service, natural gas North service and natural gas South service.

- Factor 8 (GD.AA) – Factor used to allocate common natural gas costs to natural gas services, including Natural Gas North and Natural Gas South. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to natural gas North service and natural gas South service.
  (2) Direct O&M and A&G labor that are assigned to natural gas North service and natural gas South service.
  (3) Number of customers for natural gas North service and natural gas South service.
  (4) Net direct plant that is assigned to natural gas North service and natural gas South service.

- Factor 9 (CD.AN) – Factor used to allocate costs common in Washington and Idaho to Electric service and Natural Gas North service. The 4-factor is developed using the following data:

(1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to electric service and natural gas North service.
(2) Direct O&M and A&G labor that are assigned to electric service and natural gas North service.
(3) Number of customers for electric service and natural gas North service.
(4) Net direct plant that is assigned to electric service and natural gas North service.

These factors at June 30, 2013, used in this filing, are shown in Table No. 3 below:

Table No. 3

			Allocation Percentages		
Factor	**Service Code**	**Jurisdiction Code**	**Electric**	**Natural Gas North**	**Natural Gas South**
Factor 7	CD	AA	72.346%	19.401%	8.253%
Factor 8	GD	AA	0.000%	70.320%	29.680%
Factor 9	CD	AN/WA/ID	79.221%	20.779%	0.000%
Customer Ratio of Factor 7	CD	AA	52.888%	33.009%	14.103%
Customer Ratio of Factor 8	GD	AA	0.000%	70.065%	29.935%
Customer Ratio of Factor 9	CD	AN/WA/ID	61.572%	38.428%	0.000%

The second step is to allocate the common operating costs for Electric and Natural Gas North to the appropriate jurisdiction (Washington or Idaho).

These costs are allocated using the jurisdictional allocation factors, including:

- P/T ratio (Electric Factor 1), which was described above.
- System Contract Demand ratio (Natural Gas Factor 1), which was described above.
- Factor 2 (Number of Customers) – For both electric service and natural gas North service, Washington and Idaho's proportional share of total electric customers and total natural gas North customers are used to assign certain costs, as described below.

- Factor 3 (Directly-Assigned Distribution Costs) - For both electric and natural gas North service, Washington and Idaho's proportional share of total actual directly assigned distribution O&M expenses are used to assign certain costs, as described below.

- Factor 4 (Electric Common Costs) - Factor used to allocate common electric service costs to Washington and Idaho. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to Washington and Idaho electric service.
  (2) Direct O&M and A&G labor that are assigned to Washington and Idaho electric.
  (3) Number of customers for Washington and Idaho electric.
  (4) Net direct plant that is assigned to Washington and Idaho electric service.

- Factor 4 (Natural Gas Common Costs) - Factor used to allocate common natural gas North service costs to Washington and Idaho. The 4-factor is developed using the following data:

  (1) Direct O&M and A&G costs, excluding labor and resource costs, that are assigned to Washington and Idaho natural gas North service.
  (2) Direct O&M and A&G labor that are assigned to Washington and Idaho natural gas North service.
  (3) Number of customers for Washington and Idaho natural gas North service.
  (4) Net direct plant that is assigned to Washington and Idaho natural gas North service.

- Factor 10 (Natural Gas Actual Annual Throughput) – For natural gas North service, Washington and Idaho's proportional share of total actual annual therm throughput are used to assign certain costs, as described below.

These factors at June 30, 2013, used in this filing for both electric and natural gas operations, are shown in Table No. 4 below:

Table No. 4

Factors	Service Code	Jurisdiction Code	Allocation Percentages Washington	Idaho
Electric:				
PT Ratio (Electric Factor 1)	ED	AN	65.010%	34.990%
Customer Ratio (Factor 2)	ED	AN	65.618%	34.382%
Direct Distribution Costs (Factor 3)	ED	AN	66.932%	33.068%
Common Factor (Electric Factor 4)	ED	AN	67.000%	33.000%
Natural Gas:				
System Contract Demand Ratio (Nat. Gas Factor 1)	GD	AN	69.990%	30.010%
Customer Ratio (Factor 2)	GD	AN	66.411%	33.589%
Direct Distribution Costs (Factor 3)	GD	AN	70.462%	29.538%
Common Factor (Nat. Gas Factor 4)	GD	AN	70.603%	29.397%
Actual Annual Throughput Ratio (Factor 10)	GD	AN	69.163%	30.837%

These allocation factors are applied in a jurisdictional allocation model outside of the general ledger system. This model produces the monthly Results of Operations reports. Washington's Results of Operations reports as of June 30, 2013 have been provided with my workpapers at Section 1.00 for both electric and natural gas. Additional workpapers supporting the allocations described above are provided as Andrews Workpapers (Part 3), both in hard copy and electronic formats.

Allocation Methodology

Q. Would you describe for electric service for each income statement and rate base FERC account the allocation method that is used by the Company and a brief explanation of how the use of that factor produces a reasonable allocation of costs?

A. Yes. For electric operations, Table No. 5 below summarizes the various factors that are used for each FERC account.

Table No. 5:

Line	Description	FERC Accounts	Allocation Method to Electric/Natural Gas	Allocation Method to State
	Income Statement			
1)	Sales to Customers	440-446, 448, 499	Direct Assignment	Direct Assignment
2)	Other Sales, including Sales for Resale, Rent, etc.	447, 451-456	Direct Assignment	PT Ratio (Electric Factor 1)
3)	Generation O&M - Steam Power	500-514	Direct Assignment	PT Ratio (Electric Factor 1)
4)	Generation O&M - Hydro	535-545	Direct Assignment	PT Ratio (Electric Factor 1)
5)	Generation O&M - Other Generation	546-554	Direct Assignment	PT Ratio (Electric Factor 1)
6)	Other Power Supply (i.e. Purchased Power)	555-557	Direct Assignment	Direct Assignment or PT Ratio (Electric Factor 1)
7)	Transmission O&M	560-573	Direct Assignment	PT Ratio (Electric Factor 1)
8)	Distribution O&M	580-598	Direct Assignment	Direct Assignment or Factor 3 (Directly-Assigned Distribution Costs)
9)	A&G - Customer Accounts Expenses	901-905	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
10)	A&G - Customer Service and Info Expenses	908-910	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
11)	A&G - Sales Expenses	912-916	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
12)	A&G - Other Expenses	920-927, 930-935	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
13)	A&G - Regulatory Expenses	928	Factors 7, 8 & 9 (Common Factor)	PT Ratio (Electric Factor 1)
14)	Depreciation and Amortization - Generation	403-404	Direct Assignment	PT Ratio (Electric Factor 1)
15)	Depreciation and Amortization - Transmission	403-404	Direct Assignment	PT Ratio (Electric Factor 1)
16)	Depreciation and Amortization - Distribution	403-404	Direct Assignment	Direct Assignment
17)	Depreciation and Amortization - General	403-404	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
18)	Regulatory Amortizations	407	Direct Assignment	Direct Assignment or PT Ratio (Electric Factor 1)
	Rate Base			
19)	Intangible Plant and A/D	101, 108-111	Direct Assignment and Factors 7, 8 & 9 (Common Factor)	PT Ratio (Electric Factor 1) or Factor 4 (Common Factor)
20)	Generation Plant and A/D	101, 108-111	Direct Assignment	PT Ratio (Electric Factor 1)
21)	Transmission Plant and A/D	101, 108-111	Direct Assignment	PT Ratio (Electric Factor 1)
22)	Distribution Plant and A/D	101, 108-111	Direct Assignment	Direct Assignment
23)	General Plant and A/D	101, 108-111	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
24)	Regulatory Deferred Assets and Liabilities	182, 186	Direct Assignment	Direct Assignment
25)	Working Capital	ISWC	Investor Supplied Allocation	Investor Supplied Allocation

Lines 1 through 7 – Customer revenues, generation O&M costs, power supply costs and transmission O&M costs are directly assigned to electric service in the general ledger. Revenues are primarily directly assigned to the states. The costs are either directly assigned to Washington and Idaho or are allocated to Washington and Idaho electric service using the P/T ratio. As discussed above, the P/T ratio is an equal weighting of actual usage amounts for retail customer demand and energy consumption. Since the P/T ratio is derived from actual sales data in each state, the use of the P/T ratio to allocate these costs produces a matching of costs with the revenues.

Line 8 – Distribution costs are directly assigned in the general ledger to electric service. The majority of costs are also directly assigned to Washington and Idaho. For those costs not directly assigned, the Company allocates the common distribution costs using the ratio of directly assigned distribution costs incurred in each state in comparison to the total.

Lines 9 through 11 – Customer count is one component of the 4-factors. Rather than using the over-all 4-factors (Factors 7, 8 and 9) to allocate the common costs to electric service for common portions of FERC Accounts 901-905 (Customer Accounts Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and FERC Accounts 911-917 (Sales Expenses), the Company uses the customer component ratio of the 4-factors. These costs in these FERC accounts are heavily influenced by the number of customers, and therefore, the ratio based on customers is more appropriate to allocate the costs to electric and natural gas service than the over-all 4-factor. Using the same reasoning, the Company uses Factor 2 (Customer Ratio) to allocate the common electric costs to Washington and Idaho.

Line 12 - FERC Accounts 920-927 and 930-935 (Administrative and General) include various A&G costs, including salaries, office supplies and expenses, outside services, maintenance of common general plant, etc. The over-all 4-factor allocators

(Factors 7, 8 and 9) are used to allocate the common costs to electric service and the over-all 4-factor allocator (Factor 4) is used to allocate the common electric costs to Washington and Idaho. These costs are not influenced by any one factor, so the use of the over-all 4-factor that is equally weighted with customers, direct labor, other non-labor O&M and A&G direct costs and net direct plant, produces a reasonable allocation of common costs.

Line 13 – FERC Accounts 928 (Regulatory Commission expenses) include state and FERC fees that are based on revenues, in addition to other A&G expenses of the State and Federal Regulation department. The Company directly assigns the fees to electric service. For the state commission fees, the Company directly assigns the fees paid to each state to the appropriate state. For the FERC fees, the Company uses the P/T ratio to allocate the fees to Washington and Idaho. Since these fees are based on revenues, the use of the P/T ratio to allocate the fees produces the best matching of costs with revenues in each state. For the other common A&G expenses of the State and Federal Regulation department, the over-all 4-factors are used to allocate to electric service (Factors 7, 8 and 9).

Lines 14 through 15 – Depreciation and amortization expense of generation and transmission property are allocated using the same methodology as the generation and transmission O&M costs, described above for lines 1 through 7.

Line 16 – Depreciation and amortization expense of electric distribution property are all directly assigned.

Line 17 – Depreciation and amortization expense of general plant are allocated using the same methodology as the Administrative and General costs, described above for line 12.

Line 18 – FERC Accounts 407 (Regulatory Amortizations) are primarily directly assigned to the state where the deferral of costs originated. However, for electric service, there are deferrals that were approved in both Washington and Idaho related to the Coeur d' Alene Tribe Settlement (CDA Settlement) in 2008 that were recorded as a common electric deferral that is allocated to Washington and Idaho using the P/T ratio. The CDA Settlement relates to the use of the land for Avista's hydro generating facilities. Therefore, the P/T ratio is appropriate to allocate these costs.

Line 19 – Intangible plant accounts and associated accumulated depreciation (A/D) accounts include two groups of plant: 1) general intangible plant, like software, and 2) the CDA Settlement costs that were recorded as plant in 2008. The CDA Settlement costs are all directly assigned to electric service. General intangible plant and A/D is allocated to electric using the 4-factors (Factors 7, 8 and 9). The CDA Settlement costs are allocated to Washington and Idaho using the P/T ratio, using the same reasoning as describe in Line 18 above. General intangible plant and A/D is allocated to Washington and Idaho using the 4-factors (Factor 4). The amount of intangible plant, like software, is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Lines 20-21 – Generation and transmission plant and associated A/D are directly assigned to electric service. Consistent with generation and transmission O&M costs and depreciation expenses, the rate base is allocated to Washington and Idaho using the P/T ratio.

Line 22 - Distribution plant and associated A/D are directly assigned to electric service and to each state.

Line 23 – General plant includes structures and improvements, office furniture, power operated equipment and transportation vehicles, etc. General plant and A/D is allocated to electric using the 4-factors (Factors 7, 8 and 9). General plant and A/D is allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of general plant is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Line 24 – Regulatory deferred assets and liabilities are all directly assigned to electric service and to each state that approved the deferral.

Line 25 – Working capital is computed using the investor supplied working capital (ISWC) method. Each balance sheet account is categorized. The remaining accounts (primarily non-earning short-term assets and liabilities) are allocated to service and states by the types of activity in each account. A variety of the allocation factors are used depending on the types of activity.

Q. Would you describe for natural gas service for each income statement and rate base FERC account the allocation method that is used by the Company and a brief explanation of how the use of that factor produces a reasonable allocation of costs?

A. For natural gas North operations, Table No. 6 below summarizes the various factors that are used for each FERC account.

Table No. 6

Line	Description	FERC Accounts	Allocation Method to Electric/Natural Gas	Allocation Method to State
Income Statement				
1)	Sales to Customers	480-484, 499	Direct Assignment	Direct Assignment
2)	Other Sales, including Sales for Resale, Rent, etc.	483, 488-495	Direct Assignment	Direct Assignment or Factor 4 (Common Factor)
3)	Production Expenses	804-813	Direct Assignment	Direct Assignment or Actual Annual Throughput Ratio (Nat. Gas Factor 10)
4)	Underground Storage	814-837	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
5)	Distribution O&M	870-894	Direct Assignment	Direct Assignment or Factor 3 (Directly-Assigned Distribution Costs)
6)	A&G - Customer Accounts Expenses	901-905	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
7)	A&G - Customer Service and Info Expenses	908-910	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
8)	A&G - Sales Expenses	912-916	Customer Ratio of Factors 7, 8 & 9 (Common Factor)	Customer Ratio (Factor 2)
9)	A&G - Other Expenses	920-927, 930-935	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
10)	A&G - Regulatory Expenses	928	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
11)	Depreciation and Amortization - U/G Storage	403-404	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
12)	Depreciation and Amortization - Distribution	403-404	Direct Assignment	Direct Assignment
13)	Depreciation and Amortization - General	403-404	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
14)	Regulatory Amortizations	407	Direct Assignment	Direct Assignment
Rate Base				
15)	Intangible Plant and A/D	101, 108-111	Direct Assignment and Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
16)	U/G Storage Plant and A/D	101, 108-111	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)
17)	Distribution Plant and A/D	101, 108-111	Direct Assignment	Direct Assignment
18)	General Plant and A/D	101, 108-111	Factors 7, 8 & 9 (Common Factor)	Factor 4 (Common Factor)
19)	Regulatory Deferred Assets and Liabilities	182, 186	Direct Assignment	Direct Assignment
20)	Working Capital	ISWC	Investor Supplied Allocation	Investor Supplied Allocation
21)	Gas Inventory	117, 164	Direct Assignment	System Contract Demand Ratio (Nat. Gas Factor 1)

Lines 1 through 2 – Customer revenues and other revenues are directly assigned to natural gas service in the general ledger. Revenues are primarily directly assigned to the states. There are other revenues that are allocated to Washington and Idaho natural gas service using the over-all 4-factor allocator (Factor 4). These other revenues are not influenced by any one factor, so the use of the over-all 4-factor that is equally weighted with customers, direct labor, other non-labor O&M and A&G direct costs and net direct plant, produces a reasonable allocation of common revenues.

Line 3 – Production expenses, including natural gas purchases are directly assigned to natural gas service in the general ledger. The majority of these costs are directly assigned to Washington and Idaho using the actual sales data for each month. A small amount of the costs are allocated using the prior year's actual annual throughput (Factor 10). Since all of these costs are allocated using actual sales data in each state, the use of these ratios to allocate these costs produces a matching of costs with the revenues.

Line 4 – Underground storage costs are directly assigned in the general ledger to natural gas service. The costs are allocated to Washington and Idaho using the System Contract Demand ratio. As described above, this ratio is the average of the highest 5 consecutive days of throughput for a 3-year period.

Line 5 - Distribution costs are directly assigned in the general ledger to natural gas service. The majority of costs are also directly assigned to Washington and Idaho. For those costs not directly assigned, the Company allocates the common distribution costs using the ratio of directly assigned distribution costs incurred in each state in comparison to the total.

Lines 6 through 8 - Customer count is one component of the 4-factors. Rather than using the over-all 4-factors (Factors 7, 8 and 9) to allocate the common costs to natural gas service for common portions of FERC Accounts 901-905 (Customer Accounts Expense), FERC Accounts 906-910 (Customer Service and Information Expense), and

FERC Accounts 911-917 (Sales Expenses), the Company uses the customer component ratio of the 4-factors. These costs in these FERC accounts are heavily influenced by the number of customers, and therefore, the ratio based on customers is more appropriate to allocate the costs to electric and natural gas service than the over-all 4-factor. Using the same reasoning, the Company uses Factor 2 (Customer Ratio) to allocate the common natural gas costs to Washington and Idaho.

Line 9 - FERC Accounts 920-927 and 930-935 (Administrative and General) include various A&G costs, including salaries, office supplies and expenses, outside services, maintenance of common general plant, etc. The over-all 4-factor allocators (Factors 7, 8 and 9) are used to allocate the common costs to natural gas service and the over-all 4-factor allocator (Factor 4) is used to allocate the common natural gas costs to Washington and Idaho. These costs are not influenced by any one factor, so the use of the over-all 4-factor that is equally weighted with customers, direct labor, other non-labor O&M and A&G direct costs and net direct plant, produces a reasonable allocation of common costs.

Line 10 – FERC Accounts 928 (Regulatory Commission expenses) include state fees that are based on revenues, in addition to other A&G expenses of the State and Federal Regulation department. The Company directly assigns the fees to natural gas service. For the state commission fees, the Company directly assigns the fees paid to each state to the appropriate state. For the other common A&G expenses of the State and Federal Regulation department, the over-all 4-factors are used to allocate to natural gas service (Factors 7, 8 and 9).

Line 11 – Depreciation and amortization expense of underground storage property are allocated using the same methodology as the underground storage costs, described above for line 4.

Line 12 – Depreciation and amortization expense of natural gas distribution property are all directly assigned.

Line 13 – Depreciation and amortization expense of general plant are allocated using the same methodology as the Administrative and General costs, described above for line 9.

Line 14 – FERC Accounts 407 (Regulatory Amortizations) are primarily directly assigned to the state where the deferral of costs originated.

Line 15 – Intangible plant accounts and associated accumulated depreciation (A/D) accounts includes general intangible plant, like software. General intangible plant and A/D is allocated to natural gas service using the 4-factors (Factors 7, 8 and 9). General intangible plant and A/D is allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of intangible plant, like software, is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Line 16 – Underground storage plant and associated A/D are directly assigned to natural gas service. Consistent with underground storage costs and depreciation expenses, the rate base is allocated to Washington and Idaho using the System Contract Demand ratio.

Line 17 - Distribution plant and associated A/D are directly assigned to natural gas service and to each state.

Line 18 - General plant includes structures and improvements, office furniture, power operated equipment and transportation vehicles, etc. General plant and A/D is allocated to natural gas using the 4-factors (Factors 7, 8 and 9). General plant and A/D is allocated to Washington and Idaho using the 4-factors (Factors 4). The amount of general plant is not directly influenced by just one factor, like customers; therefore the over-all 4-factors are used as a reasonable basis to allocate the rate base.

Line 19 – Regulatory deferred assets and liabilities are all directly assigned to natural gas and each state that approved the deferral.

Line 20 – Working capital is computed using the investor supplied working capital (ISWC) method. Each balance sheet account is categorized. The remaining accounts (primarily non-earning short-term assets and liabilities) are allocated to service and states by the types of activity in each account. A variety of the allocation factors are used depending on the types of activity.

Line 21 – Natural gas inventory is directly assigned to natural gas service in the general ledger. The costs are allocated to Washington and Idaho using the System Contract Demand ratio. This method is consistent with the method used to allocate underground storage costs, as described in Line 4 above.

Summary

Q. What portion of Washington's costs are allocated in the test period?

A. A summary of the costs for the test period (twelve months ended June 30, 2013) is provided in Table No. 7 below.

Table No. 7

Operating Costs
For the Twelve Months Ended June 30, 2013
($000's)

	WA Electric			WA Natual Gas		
	Direct	Allocated	Total	Direct	Allocated	Total
Power Supply/Generation & Transmission/Production/Underground Storage	$ 11,347	$ 395,045	$ 406,392	$ 136,095	$ 2,045	$ 138,140
O&M Distribution	15,401	5,734	21,135	7,898	2,758	10,656
Depreciation and Amortization	23,092	12,007	35,099	7,649	3,228	10,877
Administative and General	20,336	50,347	70,683	8,588	16,265	24,853
Taxes other than Income Taxes	39,617	-	39,617	12,532	-	12,532
Total Other Costs	98,446	68,088	166,534	36,667	22,251	58,918
Total	$ 109,793	$ 463,133	$ 572,926	$ 172,762	$ 24,296	$ 197,058

Excluding the allocated power supply, generation and transmission costs that are allocated using the P/T ratio, the Company has allocated $68,088,000 of costs to Washington electric service. This represents approximately 14% of total electric costs ($68,088/$572,926) that have been allocated to Washington electric service. Excluding the costs that are allocated using the P/T ratio, this represents approximately 41% of non-generation, transmission and power supply costs are allocated for electric service in Washington ($68,088/$166,534).

Excluding the allocated production and underground storage costs, the Company has allocated $22,251,000 of costs to Washington natural gas service. This represents approximately 11% of total natural gas costs ($22,251/$197,058) that have been allocated to Washington natural gas service. Excluding production and underground storage costs, this represents approximately 38% of non-production costs and underground storage costs are allocated for natural gas service in Washington ($22,251/$58,918).

Q. What portion of Washington's plant costs are allocated in the test period?

A. A summary of plant costs for the test period (June 30, 2013 AMA basis) is provided in Table No. 8 below.

Table No. 8

Plant Costs
Average of Monthly Averages at June 30, 2013
($000's)

	WA Electric			WA Natual Gas		
	Direct	Allocated	Total	Direct	Allocated	Total
Generation & Transmission/Underground Storage	$ -	$ 1,108,341	$ 1,108,341	$ -	$ 24,503	$ 24,503
Distribution	768,726	-	768,726	300,048	1,792	301,840
Intangible	2,762	52,535	55,296	965	7,282	8,247
General Plant	46,573	118,765	165,338	13,945	24,818	38,764
Total Other	818,061	171,300	989,360	314,958	33,892	348,851
Total	$ 818,061	$ 1,279,641	$ 2,097,701	$ 314,958	$ 58,395	$ 373,354

Excluding the allocated generation and transmission plant investment that are allocated using the P/T ratio, the Company has allocated $171,300,000 of plant costs to Washington electric service. This represents approximately 8% of total electric plant costs ($171,300/$2,097,701) that have been allocated to Washington electric service. Excluding the costs that are allocated using the P/T ratio, this represents approximately 17% of non-generation, transmission and power supply costs are allocated for electric service in Washington ($171,300/$989,360). Therefore, approximately 83% of non-generation and transmission plant costs are directly assigned for electric service in Washington.

Excluding the allocated underground storage plant, the Company has allocated $33,892,000 of plant costs to Washington natural gas service. This represents approximately 9% of total natural gas plant costs ($33,892/$373,354) that have been allocated to Washington natural gas service. Excluding the underground storage plant this represents approximately 10% of non-underground storage plant costs are allocated for natural gas service in Washington ($33,892/$348,851). Therefore, approximately 90% of non-underground storage plant costs are directly assigned for natural gas service in Washington.

Q. In summary, do you believe the allocation methodology used today by the Company is appropriate for allocating common costs?

A. Yes, I do. We believe the method used by Avista produces a reasonable allocation of costs. The allocation factors are derived using actual, directly assigned costs and other actual data points that are updated annually with current data, so growth in each service or jurisdiction is factored into the current year allocation. It has been reviewed and accepted by all jurisdictions in which Avista serves and remains a sound, rational basis for allocating costs.

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

A. Yes, it does.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/12/2015
CASE NO.:	UG 239	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 239	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

For each of the officers listed by the Company in confidential file MS Excel file "Staff_DR_175C Confidential Attachment A," where Avista provided the amounts directly assigned by the Company's officers to non-utility operations or subsidiaries,[1] please:

a. Provide the total compensation received by such officer for each year of the period beginning in 2012 thorough 2014; then break down the requested total compensation into two categories: utility operations and non-utility operations or subsidiaries;

b. Reconcile each officer's compensation that was directly assigned for non-utility operations or subsidiaries as part of question "a" of this data request, with the information provided in MS Excel file "Staff_DR_175C Confidential Attachment A"; if there is any difference in the requested reconciliation, please explain;

RESPONSE:

Please see the Company's response in Staff_DR_239C for the requested information. Staff_DR_239C is **CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER**.

Please see Staff_DR_239C Confidential Attachment A for total direct compensation for the Company's executive officers by FERC account and expenditure type (including notations of which expenses are non-utility operations). The amount of compensation for non-utility operations ties to the amounts provided in the Company's response to Staff_DR_175C Confidential Attachment A.

[1] By "non-utility" operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file "Staff_DR_175C Confidential Attachment A," worksheet "Labor". In other words, "all costs recorded for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report" as referred in the Company response to Staff DR175, part "c".

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CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31
Dollars in thousands, except per share amounts

	2013	2012	2011
Operating Revenues:			
Utility revenues	$ 1,402,195	$ 1,352,385	$ 1,441,522
Ecova revenues	176,761	155,664	137,848
Other non-utility revenues	39,549	38,953	40,410
Total operating revenues	1,618,505	1,547,002	1,619,780
Operating Expenses:			
Utility operating expenses:			
Resource costs	689,586	693,127	790,048
Other operating expenses	276,228	276,780	261,926
Depreciation and amortization	117,174	112,091	105,629
Taxes other than income taxes	88,435	83,409	83,347
Ecova operating expenses:			
Other operating expenses	148,023	139,173	109,738
Depreciation and amortization	15,434	13,519	7,193
Other non-utility operating expenses:			
Other operating expenses	38,651	38,041	33,117
Depreciation and amortization	581	792	778
Total operating expenses	1,374,112	1,356,932	1,391,776
Income from operations	244,393	190,070	228,004
Interest expense	78,755	76,894	73,876
Interest expense to affiliated trusts	467	541	332
Capitalized interest	(3,676)	(2,401)	(2,942)
Other income-net	(6,677)	(5,025)	(3,433)
Income before income taxes	175,524	120,061	160,171
Income tax expense	63,230	41,261	56,632
Net income	112,294	78,800	103,539
Less: Net income attributable to noncontrolling interests	(1,217)	(590)	(3,315)
Net income attributable to Avista Corporation shareholders	$ 111,077	$ 78,210	$ 100,224
Weighted-average common shares outstanding (thousands), basic	59,960	59,028	57,872
Weighted-average common shares outstanding (thousands), diluted	59,997	59,201	58,092
Earnings per common share attributable to Avista Corporation shareholders:			
Basic	$ 1.85	$ 1.32	$ 1.73
Diluted	$ 1.85	$ 1.32	$ 1.72

The Accompanying Notes are an Integral Part of These Statements.

NOTE 6. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2013	2012
Utility plant in service	$ 349,781	$ 344,958
Accumulated depreciation	(239,538)	(234,126)

NOTE 7. PROPERTY, PLANT AND EQUIPMENT

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2013	2012
Avista Utilities:		
Electric production	$ 1,141,790	$ 1,112,670
Electric transmission	569,056	546,019
Electric distribution	1,284,428	1,217,827
Electric construction work-in-progress (CWIP) and other	276,582	244,761
Electric total	3,271,856	3,121,277
Natural gas underground storage	41,248	40,890
Natural gas distribution	762,044	704,839
Natural gas CWIP and other	47,751	57,745
Natural gas total	851,043	803,474
Common plant (including CWIP)	327,888	272,991
Total Avista Utilities	4,450,787	4,197,742
Ecova (1)	31,865	30,138
Other (1)	20,132	22,690
Total	$ 4,502,784	$ 4,250,570

(1) Included in other property and investments-net on the Consolidated Balance Sheets. Accumulated depreciation was $26.4 million as of December 31, 2013 and $23.4 million as of December 31, 2012 for Ecova and $11.4 million as of December 31, 2013 and $13.7 million as of December 31, 2012 for the other businesses. The decrease in accumulated depreciation for the other businesses was due to the retirement of a fully depreciated asset during 2013.

NOTE 8. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

Specifically, the Company has recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease,
- remove asbestos at the corporate office building, and
- dispose of PCBs in certain transformers.

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31
Dollars in thousands, except per share amounts

	2014	2013	2012
Operating Revenues:			
Utility revenues	$ 1,433,343	$ 1,402,195	$ 1,352,385
Non-utility revenues	39,219	39,549	38,953
Total operating revenues	1,472,562	1,441,744	1,391,338
Operating Expenses:			
Utility operating expenses:			
Resource costs	678,244	689,586	693,127
Other operating expenses	286,832	276,228	276,780
Depreciation and amortization	129,570	117,174	112,091
Taxes other than income taxes	94,300	88,435	83,409
Non-utility operating expenses:			
Other operating expenses	30,418	38,651	38,041
Depreciation and amortization	610	581	792
Total operating expenses	1,219,974	1,210,655	1,204,240
Income from continuing operations	252,588	231,089	187,098
Interest expense	75,302	77,118	75,104
Interest expense to affiliated trusts	450	467	541
Capitalized interest	(3,924)	(3,676)	(2,401)
Other income-net	(11,346)	(5,167)	(2,713)
Income from continuing operations before income taxes	192,106	162,347	116,567
Income tax expense	72,240	58,014	39,764
Net income from continuing operations	119,866	104,333	76,803
Net income from discontinued operations (Note 5)	72,411	7,961	1,997
Net income	192,277	112,294	78,800
Net income attributable to noncontrolling interests	(236)	(1,217)	(590)
Net income attributable to Avista Corporation shareholders	$ 192,041	$ 111,077	$ 78,210

The Accompanying Notes are an Integral Part of These Statements.

- energy marketing and trading companies.

In addition, the Company has concentrations of credit risk related to geographic location as it operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact the Company's overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

The Company maintains credit support agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed contractual limits or when there are changes in a counterparty's creditworthiness. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):

	2014	2013
Utility plant in service	$ 350,518	$ 349,781
Accumulated depreciation	(239,845)	(239,538)

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):

	2014	2013
Avista Utilities:		
Electric production	$ 1,171,002	$ 1,141,790
Electric transmission	603,909	569,056
Electric distribution	1,360,185	1,284,428
Electric construction work-in-progress (CWIP) and other	311,807	276,582
Electric total	3,446,903	3,271,856
Natural gas underground storage	41,963	41,248
Natural gas distribution	810,487	762,044
Natural gas CWIP and other	57,088	47,751
Natural gas total	909,538	851,043
Common plant (including CWIP)	394,027	327,888
Total Avista Utilities	4,750,468	4,450,787
Alaska Electric Light and Power Company:		
Electric production	71,969	—
Electric transmission	18,392	—
Electric distribution	17,936	—
Electric production held under long-term capital lease	71,007	—
Electric CWIP and other	7,893	—
Electric total	187,197	—
Common plant	8,155	—
Total Alaska Electric Light and Power Company	195,352	—
Ecova (1)	—	31,865
Other (1)	25,803	20,132
Total	$ 4,971,623	$ 4,502,784

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	09/10/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 287	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

REQUEST:

Based on the Company-provided confidential response to Staff Data Request 239 (i.e., workbook "Staff_DR_239C Confidential Attachment A ")" where Avista provided the total compensation of selected officers for the past three years broken down into utility and non-utility operations,[1] for Officer Mr. Vermillion, Dennis, please provide the following information:

a. Title of such officer (if the title has changed during the requested period, please provide the titles including the date of changes if applicable); and
b. Duties and responsibilities of such officer (e.g., position description documents or any other documents; if the job description has changed during the requested period, please provide all the versions of such position description);

If the supporting information requested above, was derived or obtained from other sources , please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format **indicating the specific page, section, etc.** of the relevant source document.

RESPONSE:

Dennis Vermillion is President of Avista Utilities. His title has not changed between 2012 and 2015.

Please see Avista's confidential response to Staff_DR_286 for the job description of Dennis Vermillion. His job description is on page 5 of Staff_DR_286C – CONFIDENTIAL Attachment A.

[1] By "non-utility" operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file "Staff_DR_175C Confidential Attachment A," worksheet "Labor". In other words, "all costs recorder for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report" as referred in the Company response to Staff DR175, part "c".

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	08/12/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Annette Brandon
TYPE:	Data Request	DEPT:	State& Federal Regulation
REQUEST NO.:	Staff – 240	TELEPHONE:	(509) 495-4324
		EMAIL:	annette.brandon@avistacorp.com

REQUEST:

Regarding sub-part "e" of part "e" of the Company's response to Staff DR 175, where the Company represented:

"***Separate logs are not maintained to track time of employees*** *[emphasis added]*. ***The employees enter their time for each day*** *[emphasis added] and submit it electronically to the Company's payroll system every two weeks. This system is loaded into the Company's accounting/financial system. The data provided in Staff DR_175C Confidential Attachment A is an export from this accounting/financial system, so all [the] time [tracked by employees] has been provided in this attachment.*"

And,

Based on the Company-provided confidential file MS Excel file "Staff_DR_175C Confidential Attachment A," where Avista provided the amounts directly assigned by the Company's officers to non-utility operations or subsidiaries,[1] Staff has ranked in Table 1 below the following ten officers who allocated the most to non-utility or subsidiaries in year 2014:

Table 1

Non-confidential designation	Name of Officer
Officer 1	Morris, Scott L
Officer 2	Lafferty, Robert J
Officer 3	Thies, Mark T
Officer 4	Durkin, Marian McMahon
Officer 5	Rahn, Gregory
Officer 6	Woodworth, Roger D
Officer 7	Denniston, Timothy Glenn
Officer 8	Burmeister- Smith, Christy
Officer 9	Meister, Keri Marie
Officer 10	Sowl, Spencer W

[1] By "non-utility" operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file "Staff_DR_175C Confidential Attachment A," worksheet "Labor". In other words, "all costs recorded for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report" as referred in the Company response to Staff DR175, part "c".

Please respond the following questions:

a. Please provide a comprehensive explanation of why the Company does not maintain separate logs to track **employees**' time;
b. Does the Company maintain separate logs to track the time of the **officers** referenced in Table 1 above? Please provide a comprehensive information of the Company response;
c. For <u>each</u> of the officers referenced in Table 1 above and for <u>each</u> month of the last quarter of 2014 (i.e., October, November, and December of 2014), please:
   i. Provide a <u>detailed</u> description of the <u>daily</u> activities performed by such officer including the number of hours and costs that resulted in such employee charging time to non-utility operations or subsidiaries;
   ii. Reconcile the information provided in the preceding sub-question "i" with the number of hours and costs charged to non-utility operations or subsidiaries provided in Company-provided confidential file MS Excel file "Staff_DR_175C Confidential Attachment A".

Please provide any information available to each officer that justifies the number of hours and costs charged to non-utility operations or subsidiaries (e.g., officer's calendar, trip information, itinerary, meeting agenda, etc.)

RESPONSE:

a. The Company understands the term "log" to represent an excel spreadsheet or hand-written tracking either daily or hourly by employee for every task an employee performs in the respective time-period. While the Company does not maintain this type of "log", the Company **does** maintain a timekeeping system within which each individual employee enters his/her time by day, by project (which includes FERC account) for a two week period. Records maintained within this system include projects which are specific to the individuals' area of responsibility, including the appropriate General Ledger account based upon the FERC Uniform System of Accounts. In some instances the employees' time would be very specific to a given project or functional area, whereas in other instances, the employee may be more generic based on the nature of the task performed. As an example, a Transmission Engineer would charge his/her time to a specific Transmission project, whereas a Subsidiary Accountant would charge the majority of his/her time to non-utility operations. This information is then reviewed and approved bi-weekly by the individual's supervisor to insure accuracy in project selection. The timekeeping system gathers this information, summarizes it into monthly amounts, and feeds it to the general ledger in order to query for reporting purposes. The information provided in the Company's response to Staff_DR_175C Confidential Attachment A is the summary, or output, of all the daily entries made by each employee for each work day. Finally, the Company's third-party independent auditor Deloitte and Touche annually audits the timekeeping system from timekeeping entry to general ledger and reporting to actual payroll.

b. The process for tracking Executive Officer labor costs is the same process as all non-executive employees.

c. As noted in part (a) above, the Company's general ledger does not maintain <u>daily</u> records for each employee in the General Ledger. Rather, the General Ledger houses the monthly records which are a summation of the daily projects (including FERC account) the employee enters into the timekeeping system. The information provided in the Company's response to Staff_DR_175C Confidential Attachment A includes this information summarized on an annual basis. In order to obtain the monthly amount, please pull the "accounting month" selection from the database provided electronically into the pivot table provided in the Company's response to Staff_DR_175C Confidential Attachment A.

Please see the testimony of Company witness Smith Avista/500 page 15 lines 11-23 and page 16 lines 1-5 and the Company's response to Staff_DR_139 and Staff_DR_141 for additional information on executive officer allocation between utility and non-utility operations.

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	09/10/2015
CASE NO.:	UG 288	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff - Ordonez	RESPONDER:	Jeanne Pluth
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 286	TELEPHONE:	(509) 495-2204
		EMAIL:	jeanne.pluth@avistacorp.com

REQUEST:

Regarding Staff DR 240, where Staff requested the Company to provide an explanation of why the Company does not maintain separate logs to track officers' time and where Staff also requested the Company to provide a detailed description of the daily activities performed by ten officers, including the number of hours and costs that resulted from such officers charging time to non-utility operations or subsidiaries, including information available to such officers that justifies the number of hours and costs charged to non-utility operations or subsidiaries (e.g., officer's calendar, trip information, itineraries and meeting agendas, etc.)

To which the Company responded:

"*As noted in part (a) above,* ***the Company's general ledger does not maintain daily records for each employee in the General Ledger*** *[emphasis added]*."
And,

Based on the Company-provided confidential response to Staff Data Request 239 (i.e., workbook "Staff_DR_239C Confidential Attachment A ")" where Avista provided the total compensation of selected officers for the past three years broken down into utility and non-utility operations,[1] Staff has ranked in Table A below the following five officers whose respective compensations are the highest:

Table A

Non-confidential designation	Name of Officer
Officer 1	Morris, Scott
Officer 2	Durkin, Marian
Officer 3	Vermillion, Dennis
Officer 4	Feltes, Karen
Officer 5	Thies, Mark

Regardless of the fact that the "Company's general ledger does not maintain daily records for each employee in the General Ledger," for <u>each</u> officer listed in the above Table A, please provide the following information for the last three calendar years (i.e., 2012 through 2014): a list of the board meetings, including committees and subcommittees' meetings, attended by such

[1] By "non-utility" operations or subsidiaries, Staff means the operations or subsidiaries to which the Company directly assigned the costs provided in confidential file MS Excel file "Staff_DR_175C Confidential Attachment A," worksheet "Labor". In other words, "all costs recorder for Avista subsidiaries and for costs recorded by Avista Corp. for subsidiary report" as referred in the Company response to Staff DR175, part "c".

officer broken down by utility and non-utility operations. Please also include the date of each meeting and include copies of the minutes of each meeting.

If the supporting information requested above, was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format **indicating the specific page, section, etc.** of the relevant source document.

RESPONSE:

Please see the Company's response in Staff_DR_286C for the requested information. Staff_DR_286C is **CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER**.

The Company has provided the job descriptions for all officers of Avista in Staff_DR_286C Confidential Attachment A. For the 5 offices listed above, their job descriptions have been provided on the following pages:

Pages	Title	Name
1 - 2	Chairman and CEO	Scott Morris
3 - 4	Sr. VP, General Counsel, and Chief Compliance Officer	Marian Durkin
5	President of Avista Utilities	Dennis Vermillion
6 - 7	Sr. VP Human Resources	Karen Feltes
8 - 10	Corporate Secretary	Karen Feltes
11 - 12	Sr. VP Treasurer	Mark Thies
13 - 14	CFO	Mark Thies

Included in Staff_DR_286C Confidential Attachment A at pages 15-27, all other officers' job descriptions not specifically requested have been provided.

The Company has also provided the following excel spreadsheets:

Staff_DR_286C – CONFIDENTIAL Attachment B (2014 Data)
Staff_DR_286C – CONFIDENTIAL Attachment C (2013 Data)
Staff_DR_286C – CONFIDENTIAL Attachment D (2012 Data)

The data in Attachments B – D includes the hours recorded for each year by the 5 officers specifically requested in the data request. The officers' hours were summarized by the following: 1) Hours worked and recorded to non-utility; 2) Hours worked and recorded to utility; and 3) Hours not worked (i.e. vacation hours). The ratio of hours worked that were charged to non-utility were compared to total hours worked. This ratio was compared to the % of hours that the officers estimated would be recorded as non-utility. As an example, 2014 data is provided below:

2014	Durkin, Marian	Feltes, Karen S	Morris, Scott L	Thies, Mark T	Vermillion, Dennis P	Grand Total
Non-Utility	389	340	346	262	193	1,530
Non-Utility (Company 400)			2	13		15
Subtotal - Non-Utility	389	340	348	275	193	1,544
Utility	1,459	1,424	1,508	1,562	1,575	7,528
Non-Worked Hours (Recorded to Pool and Allocated)	232	316	224	244	312	1,328
TOTAL	**2,080**	**2,080**	**2,080**	**2,080**	**2,080**	**10,400**
Subtotal - Utility + Non-utility (Hours Worked)	1,848	1,764	1,856	1,836	1,768	9,072
% of Worked Labor Recorded as Non-utility	21%	19%	19%	15%	11%	17%
% of Non-utility Per Surveys	17%	13%	15%	11%	8%	
Non-utility Actual Recorded in excess of Survey	5%	6%	4%	4%	3%	

From the data above, it can be seen that in 2014, all 5 of the officers chosen actually recorded more time as non-utility than they had originally estimated.

Included in Attachments B – D, the hours recorded to non-utility have been provided for all 26 pay periods during each year. (As noted in the Company's response to Staff_DR_239, the daily hours are entered into the Company's timekeeping/payroll system and are summarized by two-week periods when imported into the general ledger.)

In 2014, Ecova (the largest operating subsidiary of Avista) was sold and AERC (Alaska property) was purchased. Therefore, all of the officers' non-utility hours were greater than usual and greater than what can be expected in 2015 and 2016.

CASE: UG 288
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

Exhibits in Support
Of Opening Testimony

October 16, 2015

STAFF EXHIBIT 1103

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-141 IN UG 288

CASE: UG 288
WITNESS: LISA GORSUCH

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1200

Advertising

Opening Testimony

October 16, 2015

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

A. My name is Lisa Gorsuch. My business address is 201 High Street, SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1201.

Q. Did you prepare exhibits for this docket?

A. Yes. In addition to my Witness Qualification Statement found in Exhibit Staff/1201, I prepared Exhibit Staff/1202, consisting of 3 pages. This exhibit contains Avista Utilities (Avista or Company) response to Standard Data Request (SDR) No. 104.

Q. How is your testimony organized?

A. I discuss the historical ratemaking treatment of advertising and marketing expense, describe my analysis, and provide my recommendation.

Q. What is your overall conclusion concerning Avista's proposed advertising expenses?

A. I conclude that Avista has met the requirements contained in the Oregon Administrative Rules (OARs) to support including its advertising expenses in the revenue requirement as filed in Docket No. UG 288. Therefore, I recommend no adjustment to reduce the test year for advertising expenses.

Q. Please set forth the Commission's rules that direct how to treat advertising-related expenses.

A. OAR 860-026-0022 describes how advertising-related expenses are addressed in a rate case. Each type of advertising expense is classified by category

(Categories A-E) and each category has a different standard for how the expenses may be included in a company's rates. Accordingly, I used these Categories to analyze the Company's advertising expenses in this docket.

Q. Please explain the meaning of these various Categories for advertising expense.

A. Category A expenses are for utility service advertising expenses and utility information advertising expense.[1] These expenses are presumed reasonable if they are no more than 0.125 percent of the gross retail operating revenues determined in the rate proceeding.[2]

Category C expenses are "[i]nstitutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A," [advertising regarding utility-service and utility information] programs,] "B," [legally-mandated advertising,] or "D"; [political advertising and non-utility advertising]."[3] There is no presumption that Category C advertising expenses are reasonable. OAR 860-026-0022(3)(c) provides "[t]he energy or large telecommunications utility shall carry the burden of showing that any advertising expenses in Category "C" are just and reasonable for rate-making purposes." The rules also require that in any rate filing under ORS 757.210 and ORS 759.180, the utility shall separately state the amount of advertising expenses in Category C. Advertising expenses in Category "E" are energy

[1] OAR 860-026-0022(2)(a).
[2] OAR 860-026-0022(3)(a).
[3] OAR 860-026-0022(2)(c).

efficiency or conservation advertising expenses that relate to a Commission-approved program.

Q. What did Avista propose to spend in its initial filing on Category A advertising expense in its 2016 budget?

A. For its 2016 advertising budget, Avista included $119,953.[4] This amount is $7,161 less than the $127,114[5] allowed per the calculation described in OAR 860-026-0022(3)(a), "presumed to be just and reasonable."

Q. Did Avista include Category B advertising expense in its 2016 budget in its initial filing?

A. Yes. The Company included $94,340.39[6] in Category B advertising expense.

Q. Did Avista include Category C or Category D advertising expense in its 2016 budget in its initial filing?

A. No. The Company did not include Category C or Category D advertising expense in its 2016 budget in its filing. The exclusion of these two categories of advertising expense is consistent with historical ratemaking treatment of advertising and marketing expenses, and per OAR 860-026-0022(3)(c)-(d), as the Company did not support the inclusion of these two categories of advertising expense in testimony.

Q. Did Avista include Category E advertising expense in its 2016 budget in its initial filing?

A. Yes. The Company included $2,698.91[7] Category E advertising expense.

[4] See Avista's response to Standard Data Request No. 104 Attachment A.
[5] See Avista's response to Standard Data Request No. 104 Attachment A.
[6] See Avista's response to Standard Data Request No. 104 Attachment A.

Q. How did you perform your analysis of Avista's proposed advertising expenses?

A. I reviewed the Company's response to a Standard Data Request and I reviewed all transactions in FERC accounts relating to advertising and marketing for the 2016 base year. In addition, I reviewed advertising expense included by Avista in its last two general rate case filings, Docket Nos. UG 246 and UG 284. As a result of this review, I found that Avista's advertising expenses are just and reasonable per the applicable rules, and in line with the Company's historical advertising spending.

Q. How do the advertising expenses proposed by Avista in its last general rate case filing[8] compare to its current proposed advertising expenses?

A. As shown in the chart below, Avista's overall spending levels have remained very consistent when the 2013 Base Year amount of $582,000 from Docket No. UG 284 is compared to the 2014 Base Year amount of $584,000 from Docket No. UG 288. The larger variance can be seen in the $599,000 historical 2015 Test Year amount from Docket No. UG 284 versus the $585,000 historical 2016 Test Year in Docket No. UG 288.

In the chart below, the Base Year amount is per the Company's Results of Operations Report. The $582,000 2014 Base Year amount is escalated by $3,000, as shown in the restated 2016 Test Year amount in Docket No. UG 288, resulting from a very small Consumer Price Index adjustment. As previously stated, Avista's advertising expenses have remained relatively flat

[7] See Avista's response to Standard Data Request No. 104 Attachment A.
[8] Docket No. UG 284

from its 2013 Base Year to its 2014 Base year, which is illustrated in the chart below.

UG 284		Historical 2015 Test Period (All numbers below are in thousands)	Base Year 2013
CUSTOMER SERVICE & INFO EXPENSES:			
Customer Assistance Expenses		192	190
Advertising		351	340
Misc Customer Service & Info Exp		56	54
CUSTOMER SVC & INFO OPERATING EXP	**Total**	**599**	**584**

UG 288		Historical 2016 Test Period (All numbers below are in thousands)	Base Year 2014
CUSTOMER SERVICE & INFO EXPENSES:			
Customer Assistance Expenses		175	175
Advertising		363	360
Misc Customer Service & Info Exp		47	47
CUSTOMER SVC & INFO OPERATING EXP	**Total**	**585**	**582**

Q. Do you recommend an adjustment to Avista's advertising expenses?

A. No, I do not.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 288
WITNESS: LISA GORSUCH

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Lisa M. Gorsuch
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst/Energy Resources & Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	College-level coursework in financial accounting, business law, business management, and economics. The Center for Public Utilities at New Mexico University. The National Association of Regulatory Utility Commissioners' (NARUC) Annual Regulatory Studies Program at Michigan State University.
EXPERIENCE:	Utility Analyst with the Public Utility Commission of Oregon (PUC) since April 2008. Primarily responsible for review of electric and natural gas company tariff filings, other electric and natural gas company rates and costs, and integrated resource planning. Serving as natural gas subcommittee member for NARUC from 2013 to present. Compliance Specialist with the PUC from June 2004 until April 2008. Responsibilities included acting as a liaison between the public, regulated utilities and various Commission staff. Review of proposed tariffs, administrative rules, and policies for evaluation of the potential impact on consumers and the regulated utilities. Identified trends, services, and policies where no statute, rule or precedent applied and recommended the appropriate action.
OTHER EXPERIENCE:	Senior Enforcement Agent with the Oregon Department of Revenue as a member of a multijurisdictional task force from 1999 - 2004. Responsibilities included, but were not limited to, investigating criminal cases for prosecution. In addition, served as liaison between task force and Oregon State Legislators.

CASE: UG 288
WITNESS: LISA GORSUCH

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

October 16, 2015

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	04/28/2015
CASE NO.:	UG ___	WITNESS:	Jennifer Smith
REQUESTER:	PUC Staff	RESPONDER:	Dana Anderson
TYPE:	Data Request	DEPT:	Energy Solutions
REQUEST NO.:	Staff – 104	TELEPHONE:	(509) 495-8199
		EMAIL:	dana.anderson@avistacorp.com

REQUEST:

For the questions below related to advertising expense, please see the definitions and descriptions in OAR 860-026-0022. For questions related to promotional activities or concessions, please see OAR 860-026-0015 & 0020.

a. Please identify the Category A advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
b. Please provide a work paper that shows the calculation of the Category A limit provided in OAR 860-026-0022 (3) (a);
c. If the Test Year Category A advertising expense exceeds the OAR 860 026-0022 (3) (a) limit, please provide support for including the additional expense in rates;
d. Please identify the Category B advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
e. For any Category C advertising expense included in the Test Year revenue requirement that is associated with a promotional activity or a promotional concession program, please provide a summary table that includes:
    i. A description of the activity or program, and justification for inclusion into rates;
    ii. A breakout of the related expense by labor & non-labor; and
    iii. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.
f. Please identify any other budgeted advertising expense for the test year that will NOT be included in base rates, including below-the-line or nonutility expense, or advertising expense expected to be collected through a tariff. Please include how the expense is allocated between the categories identified in

OAR 860-026-0022(2). Please describe the activities and associated expense (broken out by labor & non- labor) associated with marketing research and sales activities (include fuel switching and retention of customers) that is included in the test year. Please include references to the testimony and exhibits, and to which FERC and internal utility accounts this expense is booked.

RESPONSE:

a. Please see the Miscellaneous Restating Adjustment (1.02), in Smith workpapers, section G-MR-1 and MR-AD-1 through MR-AD-2. This adjustment 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. However, the analysis of the Company's Category A expenses determined there was no adjustment necessary pursuant to OAR 860-026-0022.

   The Company spent approximately $119,953 for Category A advertising. The Company determined that the Category A limit was approximately $127,114, so there was no adjustment necessary. Please see Smith workpapers, adjustment 1.02, workpapers reference MR-AD-1 through MR-AD-2. Workpaper MR-AD-2 includes detailed listings of advertising costs, separately identified for Category A.

b. Please see the Miscellaneous Restating Adjustment (1.02), in Smith workpapers, section MR-AD-1, for a calculation of the Category A limit provided in OAR 860-026-0022 (3)(a).

c. The test year Category A advertising expense did not exceed the OAR 860-026-0022 (3)(a) limit included in the 2014 test year. Please see the Miscellaneous Restating Adjustment (1.02), in Smith workpapers, section G-MR-1 and MR-AD-1 through MR-AD-2, for the analysis of the Category A expenses.

d. Please see Staff_DR_107, Attachment A, for all Category B advertising expenses included in the test year.

e. No Category C advertising expenses were included in the forecasted test year. Please see Staff_DR_107, Attachment A, for Category C advertising expenses.

f. All Category D and Category E costs are recorded based on direct assignment. The Company has not spent any money on political advertising (Category D Expenses). Please see Staff_DR_107, Attachment A, for program specific advertising expenses (Category E Expenses) during the test period.

g. The Company also provides detail transactions for DSM expenses in a quarterly report filed by Avista and audited by the Oregon PUC.

   Please see Staff_DR_107 Attachment A for a listing of all advertising expenses that were charged below the line to nonutility expense.

This information is in the form of an Excel file and can be found on the CD that was filed with the Filing Center or for Parties on Huddle as UG 288 Exhibit 102 pg 3 Gorsuch Attachment A.

CASE: UG 288
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

October 16, 2015

STAFF OPENING TESTIMONY

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

A. My name is George R. Compton. I have been employed by the Public Utility Commission of Oregon (OPUC) since March of 2007. I am a Senior Economist (half-time) within the Energy, Rates, Finance, and Audits Division. My business address is 201 High St., Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. This testimony addresses elements of cost allocations, rate spread (i.e. the allocation of the overall revenue increase among the various customer schedules), and pricing/rate design.

Q. Does Staff possess a general philosophy or approach to these subjects?

A. Yes. As a general matter, pricing and customer cost allocations should reflect "long-run-incremental cost" (LRIC) causation as much as possible. Achieving that objective is tempered by long-recognized "rate shock" considerations which may limit percentage increases to selected schedules' revenue requirements and particular tariff elements.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following exhibits.

Exhibit 1302	Customer Costs and Customer Charge
Exhibit 1303	DR No. 296; Line Extension Averages; Rate Spread
Exhibit 1304	Ind. Rate Reductions' Impact on Res. Customers

Q. How is your testimony organized?

A. This testimony is organized as follows:

Q. Please provide an overview of your testimony.

A. Over the years Avista Utilities' (Avista or Company) practices relating to my areas of responsibility have evolved in a mutually acceptable manner—being influenced by various parties, including Staff. In that regard Staff has no issue with the general costing and rate spread approaches taken by the Company in this case. However, some of the Company's estimates pertaining to customer schedules' average line extension footages—the dominant gas utility cost-causation factor—were challenged. This led to refinements in those estimates, which in turn had an effect on the final rate spread outcome.

On the subject of rate design, Staff's position is that although the proposed monthly customer charges for Residential Schedule 410 and General Service Schedule 420 have relatively sound cost-causation foundations, the respective two and six dollar increases are out of line percentage-wise with the general level of increase sought by Avista in this case. Staff supports increases of half those amounts.

As in the last general rate case for the Company (Docket 284), the cost of service conclusions that support substantial rate reductions for large industrial customers were corroborated by Staff's own studies. For various reasons surrounding the notion of cost-based rates, Staff again supports selected rate reductions in this general rate case—on the condition that the expected overall increase, including natural gas costs, is modest, say no greater than four percent. Otherwise, and in the interest of rate shock mitigation for other customers when the average percentage increase is more substantial, Staff favors holding the affected large industrial customers to no increase.[1]

Topic 1: Residential and General Service Customer Charges

Q. There is a common industry practice of categorizing costs as either demand, energy, or customer related. Would it be appropriate to recover all of customer costs through the monthly customer charge?

A. No. The practice I am familiar with here in Oregon and which I have espoused my entire career is that, at most, customer-related costs appropriately recovered in the customer charge are costs that are confined to individual customers—i.e., not shared in any way. Those costs that are not shared would include each customer's meter and service line, meter reading, and preparing and mailing customer bills as well as processing the payment. Other customer related costs, such as the utility's information systems hardware and personnel, are shared among all customers—and for a host of functions besides billing customers. These, and other shared gas utility costs

[1] Staff did not assert this condition in the previous Avista general rate case.

that are categorized as neither demand- nor energy-related, are historically recovered through volumetric energy charges.

Q. Has the Company provided estimates for Residential Schedule 410 and General Service Schedule 420 for the narrowly defined customer-related costs that you just described?

A. Not quite. Line 30 of my Exhibit Staff/1302[2] displays the costs that the Company apparently believes should underlie the customer charge.[3] That line is labeled "Avg Cost Per Month for Meter Reading, Billing, Meters & Service." The line 30 figures are constructed by adding the embedded cost figures on lines 21 and 22, and dividing by the customer-months (i.e., twelve times the customer counts shown on line 2). Lines 21 and 22 are labelled, respectively, "Meter Reading, Billing, Etc. [emphasis added] Costs," and "Meters & Service Costs." I believe the "Etc." costs of line 21 take us well beyond the narrowly defined customer-related costs described above.

Q. Please explain the basis for that belief.

A. Two lines of evidence support my belief that the referenced line 30 goes beyond individual customer-specific costs. First, I compare line 21 with the lines 7 and 8 figures which sum to create an LRIC correlated with the embedded cost figures of line 21. (Line 7 is labeled "Meter Reading;" line 8 is labeled "Billing.") Unless the line 21 costs went well beyond the narrowly defined items listed above, I would not expect the line 21 amounts to exceed

2 This exhibit consists of Avista/801, Miller/1, augmented with my lines 8a, 22a, and 30a.
3 Unless indicated otherwise, the spreadsheet lines referenced for the next few pages of this testimony will refer to this same Exhibit Staff/1302.

the sum of lines 7 and 8. Instead, line 21 runs in excess of 40% above the sum of lines 7 and 8.

My second point is that I believe even the smaller line 8 elements overstate narrowly-defined billing costs. (I should note that the much smaller amounts shown on line 7 look plausible to me.) Defined narrowly, "billing" would involve a bill insert, an envelope, and a stamp, plus some labor to open the envelope and post the payment. Dividing the SCH 410, line 8 amount ($2,151,696) by the number of customer-months (i.e., 12 x 87,065 [from line 2]) yields a bit over $2 per month. The cost of the bill insert, envelope, and metered "stamp" should not be much over 50 cents. I do not believe the individual computer and manual bill processing would amount to anything close to the additional $1.50 per month. Something like 25 cents would seem conservative on the high side to cover the cost of those latter items.

Q. What do you think would be a better estimate of meter reading and billing cost—narrowly defined as you would have them, and as applied to the contested schedules 410 and 420?

A. For meter reading, I would hold with the Company (i.e., line 7); for billing, I would use the 75 cents referenced in my answer to the previous question. Multiplying 75 cents and the respective customer-months yields the figures shown in line 8a of the exhibit.

Q. The Company used embedded costs on line 22 ("Meters & Services Costs") in developing the customer-related costs shown on line 30. Should the Company instead have used the corresponding LRIC sums

of lines 9 and 10 (respectively, "Meters" and "Services")? Those sums are more than twice the line 22 amounts.

A. Actually it is the attributable-embedded costs, not the larger LRIC costs, which each customer schedule will be required to recover. Also, what the Company is trying to justify is a conservative/minimum customer charge amount…not some feasible larger amount.[4] For that same reason I have preferred using the smaller, more justifiable LRIC amount for meter reading and an even smaller amount for billing.

Q. You have suggested how "Billing Costs" can go beyond your narrow definition by, for example, including generic information system costs. Are you concerned that the Meter, Services, and Meter Reading might be similarly expanded upon?

A. No, I believe the accounting codes for those items are sufficiently restrictive to not cause a problem. But I do have one caveat on this general subject. Other Staff members are providing evidence in this case for reducing Company salaries, benefits, and other expenses. Those adjustments would cause a slight reduction in the amounts that I will now be presenting to you.

Q. Would you now please reconstruct what would be your best estimate of minimally-construed customer costs that would be the candidates for including in the monthly customer charge? Please also place the amounts in a per-customer-month framework.

[4] Another consideration: Large customer charges translate to smaller volumetric energy charges, which, in turn, go against the goal of encouraging energy conservation.

A. Line 22a of my Exhibit Staff/1302 is the sum of lines 7 (meter reading), 8a (billing), and 22 (meters and services). The per-customer, monthly Line 30a figures are obtained by dividing the line 22a figures by the associated customer-months (12 times line 2). These calculations yield a $15.87 per month cost for Schedule 410 and $19.94 per month for Schedule 420.

Q. Avista is asking to increase its Schedule 410 customer charge from $8 to $10 per month, and its Schedule 420 customer charge from $14 to $20. The minimally-construed customer costs which you just produced are, respectively, $15.87 and $19.94.[5] The first is well above what the Company seeks for its customer charge, the second is just a few cents below. But from your introduction I see that Staff would only concur with increases of half what the Company seeks. Please explain why.

A. If Avista receives the revenue increases that it has applied for, then the average billed revenue increases for those two schedules will be, respectively, 8.9 percent and 9.5 five percent.[6] Raising the customer charges by, respectively, 25 percent and 43 percent in this context is too great given the overall price increase. This is especially true if the final overall increases are only about half of the Company's requested amounts.,

Q. Given that Staff supports half the requested customer charge increases, is that without conditions?

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5 From line 30a of Exhibit Staff/1302.

6 *See* column k of Avista/903, Ehrbar/3. That exhibit is replicated as the table found in my Exhibit Staff/1304.

A. No. The condition is that the customer charge increase for Schedules 410 and 420 should be limited to where, if it were any greater, there would have to be a compensating decrease in the volumetric/energy rate. Unless there is to be a general rates decrease in this case, Staff would object to energy rate decreases for those two schedules.

Topic 2: Line Extension Footage Averages and Allocated Costs

Q. In your introduction you said you are generally accepting of the costing and rate spread approaches taken by the Company in this case. But you took exception to the line extension footages. Before telling us what caused you to reach that conclusion, would you please explain what line extensions are?

A. Line extensions are the gas mains that run through the residential, commercial, and industrial neighborhoods. (*Core* mains take the gas into those neighborhoods.) The primary cost drivers for line extensions are the customers’ frontages that must be passed by to get to the next customer and so on.

Q. What caused you to take exception to the line extension footages submitted by the Company in its general rates relief application?

A. Between the Avista’s last general rate case docket (No. UG 284) and this one, the indicated per-customer average line extension footage for Schedule 420 increased by almost 60%, and to a level that was almost 50% above the average shown for Schedule 424.[7] Industrial/regulatory common sense was thereby defied in two respects: 1) With relatively large numbers of customers involved with Schedule 420 (more than eleven thousand), such a large move was simply implausible; and, 2) The small industrial/commercial enterprises that populate General Service Schedule 420 would not be expected to command lengthier line extensions than the larger enterprises that make up Schedule 424.

Q. Did you submit a data request and make other inquiries to determine what was causing what you perceived as anomalous average line extension footage estimates?

A. I did.

Q. What did you learn?

A. There were sampling discrepancies and a related disconnect between the construction information that has been compiled and what is most appropriate for cost-allocations purposes.

Q. Please present the average footage estimates which you obtained from your inquiries and compare them with those from Avista's original filing.

A. Page 1 of Staff/1303 is a replication of Avista's response to Staff's DR No. 296 —augmented as indicated by the two shaded lines. It is based upon the installation of gas mains by the Company for the previous seven years. The initial focus here is on General Service Schedule 420. The original filing showed an average of 568 feet; I believe 436 feet constitutes a superior

[7] The average footage estimates filed by Avista in this case are shown in line 8 of Avista/801, Miller/2.

estimate. Regarding the average shown for Residential Schedule 410, it is close to the original but requires some adjustment and is discussed below. Other information provided by the Company caused me to increase the average estimate for Large General Service Schedule 424 from 382 feet (in the original filing) to 494 feet. In the case of Schedules 440, 444, 447, and 456 (whose combined customer count is less than one hundred) there was no data for the same seven-year period since all the customers in those schedules came into the system ahead of that time. Fortunately, the originally recorded line extension footages were available to be used for those schedules.

Line 8 of Page 2 of Staff/1303 shows what I believe are the more accurate line extension footage estimates. For reference, the line immediately above line 8 shows the figures used by Avista in its rate case application.

Q. The context in which Oregon's utility cost studies are conducted usually focuses on the long run, i.e., LRIC (long-run incremental costs). Does your reliance upon historical footages rather than projected figures[8] constitute a violation of Staff's policy in this case?

A. No. When the objective is to capture the costs of something—especially if the subject, such as Avista's inventory of customers, is relatively static in time—sampling of existing units rather than attempting a forecast of the costs of incremental, or new units, will often produce the most accurate measure of

[8] Projections are typically extrapolations from the most recent experiences.

the entire population that is in place during the forecasted test period.[9] After all, the forecasted test period will be populated mostly with units that were installed in the past.

The theoretical underpinning for desiring forward-looking incremental costs is to achieve the economic ideal of marginal-cost pricing. When new equipment or other new resources are involved in the sale of a good or service, efficiency is fostered by having the price of that good or service reflect those new resources' costs. For existing equipment, current costs for that equipment should also be used in place of the original cost—both in pricing and in the initial, i.e., LRIC, cost-allocations phase.[10]

Q. Return now to Page 1 of Staff/1303 and your two added lines regarding Schedule 410. On what grounds did you eliminate the results for year 2009?

A. At four times the average that includes those results, the average for the two customers shown constitutes a clear outlier—unrepresentative of the group as a whole. There is also the point that while the installations averaged over two thousand feet on a physical basis, for rate-making purposes the equivalent of a smaller number of feet should have gone into the rate base.[11] That is due to the standard, Company-followed utility policy of requiring a customer to pay for whatever portion of the main extension costs that are not

[9] Test periods seldom go more than one calendar year beyond the date of the rate case application.
[10] Note 1: Line 10 of page 2 of Exhibit 1303 shows current unit costs of pipe. Note 2: Main extensions are not priced separately in the various customer tariffs. Instead, those costs are recovered through the volumetric (i.e., per therm) charges.
[11] It is the rate base that gets allocated among customer schedules, not necessarily the original construction costs (as subsequently depreciated).

expected to be covered, over time, by the volumetric basic distribution prices. That is the “disconnect” to which I made reference above. This same two-point rationale was employed to reduce the Company’s updated estimate of the Schedule 424 average main extension footage from 771 feet to 494 feet.

Q. Referring to the Residential Schedule 410 average main extension footage estimate of 91 feet shown on line 8 of Page 2 of Staff/1303, I observe that it is beneath the Schedule 410 weighted average of 103 feet shown on Page 1 of Staff/1303. Please explain the basis for lower estimate.

A. Schedule 410 represents over 87 thousand customers.[12] In estimating the per-customer average footage for that schedule the Company used the slightly over one thousand Schedule 410 installations which took place in the last seven years.[13] Making inferences from a sample can often be problematic. In this case there is potential problem in basing an estimated average which applies to 87 thousand customers upon only seven years and those one thousand customers. It is also true that with a relatively small sample size what is viewed as an unrepresentative year can lead to a major distortion in the estimated average. The years 2006 and 2007—which preceded the seven years to which I just referred—were regarded by the Company as unrepresentative insofar as those two years account for almost three-fourths of the residential customers added to the system in the last nine years, and the average footages for those years are very much below the

[12] *See* Line 2 of Page 3 of Staff/1303.
[13] That average and each year’s installation record are shown on Page 1 of Staff/1303.

average for the subsequent seven years. But while the 2006/2007 years were unrepresentative of the Company's more recent experience, I was uncomfortable about simply disregarding them.

Q. What caused the 2006/2007 years to have smaller average footages?

A. Very large new development additions took place in those years. In the other years single family additions tended to dominate. With new developments there is the advantage of a given segment of main being able to serve both sides of the street.

Q. Were you able to obtain data that would enable you to distinguish between new development main additions and single family additions going back far enough in time to obtain an accurate picture of the entire residential portion of the grid?

A. No. This kind of data only goes back nine years, of which the earliest two years are the years judged by the Company as unrepresentative.

Q. Would you expect that in the early development period for this utility that new developments would contribute relatively more to main extension additions than would be the case more recently?

A. Many of the "new developments" meant taking the gas lines into existing neighborhoods. The average lengths per customer would depend upon what proportions of the neighborhoods became enrolled as utility customers. My expectation is that in the distant past new developments played a greater role than recently with regard to residential main additions.

Q. With little more than an "expectation," how do you intend to obtain an estimate of Residential Schedule 410 average main extensions that you can use in constructing a set of cost allocations that lend themselves to putting forth a defensible "spread of rates" among the customer schedules?

A. If I were to simply use the 103 foot Residential Schedule 410 main extensions average found on page 1 of my Exhibit Staff/1303, the cost-of-service outcome would be a Residential Schedule 410 percentage rate increase that was significantly above that of General Service Schedule 420. My strategy is to reduce the Schedule 410 average footage estimate to the point—call it parity—where that Schedule and Schedule 420 receive the same billing percentage increase and then judge whether that estimate is plausible. The parity figure is the 91 feet shown on Line 8 of Page 2 Exhibit Staff/1303. Line 34 of Page 3 Exhibit Staff/1303 shows Schedule 410 and 420 receiving the same percentage increase on a billings basis and assuming zero increases/decreases for the other schedules.

Q. What is the point of targeting billing percentage increase parity between Schedules 410 and 420?

A. In Staff's view there is insufficient evidence to recommend either rate schedule having a smaller percentage increase than the other.

Q. The Company's application has Schedule 410 receiving a smaller cost allocation than Schedule 420[14] despite using a larger estimate of

[14] *See* Line 29 of Avista/801, Miller/1.

Schedule 410 average main extensions, i.e., 112 feet versus your 91 feet. Please explain that apparent anomaly.

A. The difference is that the revised Schedule 420 average footage was 132 feet below the 568 figure shown in the application. The change in relative proportions between Schedule 410 and Schedule 420 is what caused more costs to be allocated to Residential Schedule 410.

Topic 3: Industrial Schedule Rate Reductions

Q. I observe from Exhibit Avista/903, Ehrbar/Page 2 of 4 that the Company is seeking a 16% *margin* revenue increase, which translates to an 8% total *billed* revenue (or overall) increase. What is the distinction between those two revenue items?

A. The total billed revenue includes the recovery of the purchased gas costs; the margin is limited to the utility's own incurred costs (i.e., not including gas purchase costs), including a return on its capital. Since the standard natural gas utility is basically a gas distribution company, margin revenues are also referred to as "distribution revenues."[15]

Q. From that same Company exhibit I observe that Avista is proposing to *reduce* the margin revenues from some of the large customer schedules by seven percent. What is Staff's policy with regard to there being selective rate reductions in the presence of a general rates increase?

[15] *See,* for example, Exhibit Avista/903, Ehrbar/3.

A. Staff's general orientation is that rates and schedules' revenue requirement shares should approximate a marginal cost construct as much as can be reasonably justified. The desire to move rates down to costs is tempered in the presence of a general billed revenue increase that is, say, well above general price inflation. In those cases, i.e., where there is a sizable increase, in order to mitigate the rate shock experienced by the schedules receiving the bulk of the revenue requirement increase, it is Staff's preference to substitute a zero percent increase for the decrease(s) otherwise justified by the cost of service studies.

Q. Why do you apply the shock threshold to the billed revenue increase rather than the margin increase?

A. It is what the customer pays—i.e., his billing—that may shock him, not some obscure tariff item buried in his bill.

Q. Recalling that the Company is seeking a billed revenue increase of 8%, is that far enough above general inflation expectations for Staff to recommend no decreases regardless of the cost of service results?

A. It is far enough. But bear in mind that, considering its many accounting and cost of capital adjustments, Staff is not expecting the Company to actually see that much of an increase.

Q. What is a benchmark increase that would signal Staff's endorsements of rate reductions?

A. If the overall total bill rate decrease is no more than four percent *and* there are compelling cost study results, Staff would be supportive of providing some customers rate decreases while other schedules receive rate increases. Staff believes the more likely result in this rate proceeding is to achieve the four-percent condition. In that event Staff's cost studies clearly support reducing the target margin revenues for Schedules 424, 444, and 456 by as much as the Company's proffered seven percent.

Q. Do you propose any limit on the size of the rate decreases if in fact there are compelling reasons to justify providing rate decreases to some customers and rate increases to others?

A. Yes there should be some constraints on the level of rate decrease and it would be reflective of two considerations. First, if the authorized overall average billing percentage increase is four percent, the size of any non-transportation schedule's billing percentage decrease should be no greater than four percent.[16] When the overall rate decrease is smaller, then larger percentage decreases might be accommodated. The other consideration is that the rate decrease provided to some customers should not cause the total billed rate increase to any other customers to be more than two percent greater than what would otherwise have occurred. (Then, instead of allowing a rate decrease, the subject schedules would again be held to a zero percent rate increase.)

[16] An exception is made for transportation customers owing to the fact that, unlike the case of the other customers, transportation customers buy their gas from a third party and therefore the billing revenues for transportation customers is the same as the margin revenues. For these customers, the upper limit would be placed on the percentage decrease in margin revenues, and here the maximum would be the same as the largest percentage margin decrease allowed for non-transportation customers.

Q. Have you prepared an exhibit which illustrates Staff's rate spread recommendations in your hypothetical sub-four percent average billings increase?

A. Yes, it is Page 4 of Exhibit Staff/1303.

Q. Assuming that all three of the schedules shown in Exhibit Avista/903, Ehrbar/3 as receiving the seven percent decreases actually got such, and that the "burden" of the decrease was shared uniformly percentage-wise across Schedules 410 and 420, what would be the impact on a typical residential customer?

A. My calculation is that the impact would be about $1.97 per year, or only 16 cents a month. (Annual bills at current rates average $763.)

Q. Have you prepared an exhibit in support of those figures?

A. Yes, Exhibit Staff/1304.

Q. In supporting the original Settlement Stipulation in the last Avista general rate case[17] the Citizens' Utility Board (CUB) wanted "it to be clear that there is no precedent being established by the agreed-upon one-time rate spread contained within this Docket, and that…CUB…is not agreeing with the general proposition that when costs are generally increasing, some customers should receive price signals suggesting that costs are decreasing." First, is there some precedent for the OPUC to allow selective decreases in the context of a general increase?

[17] Docket No. UG 284.

A. There is. Order No. 12-408 of Docket UG 221 allowed a five percent base margin decrease for industrial customers of Northwest Natural.

Q. Do you see some kind of danger in this case in having large industrial customers "receiv[ing] price signals suggesting that costs are decreasing"?

A. No. These customers have trained professionals watching the energy markets, and they will not be misled by a modest effort to bring gas utility margins in line with costs. Their companies' profits depend on controlling costs, so a modest reduction will not lead to some kind of wasteful natural gas consumption.

Q. In Avista's last general rate case the Commission's "questioning" of the selected rate reductions caused an amended stipulation to be submitted which changed the decreases to zero increases. While the Commission "acknowledged that rates may be misaligned relative to cost-of-service and that rate cases provide opportunities to make adjustments that more closely align rates with costs….[it stated that] without compelling evidence that those adjustments warrant more immediate action, …we are not inclined to raise some rates while reducing others."[18] Would you infer from that language that "more immediate action" was unnecessary due to the anticipation of there being another rate case filing in the near future which would provide the Commission with the opportunity to take the ultimately desired action?

[18] *See* page 5 of Order No. 15 109.

A. I don’t know, but a new case has been filed, and Staff sees no reason why industrial customers should await for some indefinite time in the future to *start* to see the rate reductions whose cost-causation basis was undisputed in the prior Avista general rate case and whose general magnitude is unlikely to be disputed in the current case. The small revenue shifts displayed in Staff/1304 and on Page 4 of Staff/1303 are unlikely to have significant economic efficiency effects. But from the viewpoint of promoting social equity by reducing inter-class cross-subsidization, when Company and Staff evidence hold that margin percentage decreases should range from 19 to 35 percent, then the burden should be to produce a compelling reason why a mere 7 percent industrial margin decrease *cannot* be part of the outcome of this case—especially when the impact on residential customers is only 0.3%.[19]

Q. Does this conclude your direct testimony?

A. Yes.

[19] *See* Staff/1304

CASE: UG 288
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

October 16, 2015

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance & Audit Division

ADDRESS: 201 High Street, SE., Suite 100
Salem, OR. 97301

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Department of Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181 and 284), PGE General Rate Cases (UE 197, UE 215, UE 262, and UE 283), PacifiCorp General Rate Cases (UE 210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UG 288
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

October 16, 2015

Restricting the Cost Elements in the Customer Charge

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

RESULT SUMMARY ***(Component Allocation)***

Line No.			OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS									
1	2016 ANNUAL THERM DELIVERIES		131,581,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
2	2016 CUSTOMERS		98,647	87,065	11,416	83	35	9	3	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER			563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4	Gas Commodity Costs	$	-	-	-	-	-	-	-	-
5	Gas Supply Department (Scheduling)	1.03189 $	56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)	$	142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading	$	116,123	102,489	13,439	98	41	11	4	42
8	Billing	$	2,437,937	2,151,696	282,139	2,051	865	222	74	890
8a	Billing -- **Narrowly defined**			783,582	102,746					
	Customer Installation Investment Cost									
9	Meters	$	4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
10	Services	$	41,791,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	260,891
11	Main Extensions	$	107,857,825	63,792,293	42,572,013	331,741	229,674	35,972	18,573	877,559
12	Total Customer Installation Investment Cost	$	154,509,966	103,163,613	49,134,017	530,280	385,846	58,309	47,507	1,190,394
	System Core Main Cost									
13	Capacity	$	12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14	Commodity	$	12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost	$	24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost	$	1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost	$	183,135,015	116,711,603	55,237,265	1,249,150	1,018,121	84,421	981,338	7,853,118
18	**Distribution Margin Revenue at Present Rates**	$	**53,224,000**	**34,864,000**	**13,605,000**	**687,000**	**463,000**	**44,000**	**231,000**	**3,330,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components									
19	Cost of Gas Commodity	$	-	-	-	-	-	-	-	-
20	Gas Supply Department Costs	$	568,000	303,900	165,043	28,446	24,644	1,603	6,899	37,466
21	Meter Reading, Billing, Etc. Costs	$	3,686,000	3,253,222	426,575	3,101	1,308	336	112	1,345
22	Meters & Services Costs	$	18,599,000	15,696,325	2,616,101	79,152	62,262	8,905	11,535	124,719
22a	Meters, Services, Meter Reading, and Billing Costs **Narrowly defined**			16,582,396	2,732,286					
23	System Core Main Costs	$	37,367,000	20,945,150	13,517,845	282,414	231,271	17,072	265,373	2,107,874
24	Underground Storage Costs	$	1,561,000	906,149	480,161	53,680	46,934	1,002	11,364	61,709
26	Proposed Cost	$	61,781,000	41,104,746	17,205,725	446,794	366,419	28,919	295,284	2,333,113
25	**LRIC Based Target Margin per Avista Application**	$	**61,781,000**	**$ 41,104,746**	**$17,205,725**	**$ 446,794**	**$ 366,419**	**$ 28,919**	**$ 295,284**	**$ 2,333,113**
26	Current Distribution Margin Revenue to Proposed Cost		**0.86**	**0.85**	**0.79**	**1.54**	**1.26**	**1.52**	**0.78**	**1.43**
27	**Relative Margin to Cost at Present Rates**		**1.00**	**0.98**	**0.92**	**1.78**	**1.47**	**1.77**	**0.91**	**1.66**
28	Component LRIC Target Increase by Schedule	$	8,557,000	$ 6,240,746	$ 3,600,725	$ (240,206)	$ (96,581)	$ (15,081)	$ 64,284	$ (996,887)
29	Target Increase as a Percent of Present Distribution Margin Revenue		16.08%	17.90%	26.47%	-34.96%	-20.86%	-34.28%	27.83%	-29.94%
30	Avg Cost Per Month for Meter Reading, Billing, Meters & Services **(Company)**			$ 18.14	$ 22.21	$ 82.58				$ 291.82
30a	Avg Cost Per Month for Meter Reading, Billing, Meters & Services **(Staff/Narrowly defined)**			$ 15.87	$ 19.94					

Notes:

Line 8a = $0.75 x 12 x Line 2
Line 22a = Line 7 + Line 8a + Line 22
Line 30a = Line 22a / (12 x Line 2)

CASE: UG 288
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

Exhibits in Support
Of Opening Testimony

October 16, 2015

Attachment A to Avista's Response to Staff's DR 296

Schedule 410

	Feet	Customers	Feet/Cust	
2008 Residential	41,029	370	111	
2009 Residential	10,253	142	72	
2010 Residential	11,022	134	82	
2011 Residential	3,180	24	133	
2012 Residential	4,985	41	122	
2013 Residential	23,000	225	102	
2014 Residential	16,292	127	128	
Totals	109,761	1,063	**103**	**Weighted**
			107	**Non-weighted**

Schedule 420

	Feet	Customers	Feet/Cust	
2008 Commercial	17,649	42	420	
2009 Commercial	4,158	2	2,079	
2010 Commercial	0	0	0	
2011 Commercial	3,344	7	0	
2012 Commercial	2,085	6	348	
2013 Commercial	3,212	5	642	
2014 Commercial	765	2	383	
Totals	31,213	64	**488**	**Weighted**
			553	**Non-weighted**
Excluding 2009 (Staff Recommendation)				
Totals	27,055	62	**436**	**Weighted**

Updated Main Extension Average Footages

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

INCREMENTAL INVESTMENT COSTS

Line No.			Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	SERVICE INSTALLATIONS	48 yr life							
1	TYPICAL SERVICE PIPE SIZE		3/4"	3/4"	1 1/4" - 2"	1/2" - 1.25"	1 1/4" - 2"	3/4" - 2"	1/2" - 2"
2	AVERAGE SERVICE COST		$ 2,342.11	$ 2,633.95	$ 10,227.33	$ 19,629.92	$ 10,227.33	$ 29,981.42	$ 41,129.20
3	LEVELIZED PLANT COST FACTOR		0.1762	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
4	ANNUAL REVENUE REQUIREMENT		$ 412.68	$ 464.10	$ 1,802.06	$ 3,458.79	$ 1,802.06	$ 5,282.73	$ 7,246.97
	METERS & REGULATORS	36 yr life							
5	METERS & REGULATORS		$ 216.00	$ 604.88	$ 3,223.91	$ 5,482.40	$ 3,714.67	$ 23,836.64	$ 7,884.75
6	LEVELIZED PLANT COST FACTOR		0.1830	0.1830	0.1830	0.1830	0.1830	0.1830	0.1830
7	ANNUAL REVENUE REQUIREMENT		$ 39.53	$ 110.69	$ 589.98	$ 1,003.28	$ 679.78	$ 4,362.11	$ 1,442.91
	MAIN INVESTMENT	58 yr life							
	AVERAGE MAIN EXTENSION PER CUSTOMER	Original Filing	112	568	382	498	382	792	1,165
8	AVERAGE MAIN EXTENSION PER CUSTOMER	**Updated**	91	436	494	498	382	792	1,165
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	sample	dedicated plt	same as 424	dedicated plt	dedicated plt
10	AVERAGE COST PER FOOT		$ 37.23	37.23	50.29	$ 74.74	50.29	$ 44.36	$ 118.66
11	MAIN EXTENSION INVESTMENT		$ 3,387.93	$ 16,232.28	$ 24,843.26	$ 37,221.25	$ 19,210.78	$ 35,133.12	$ 138,238.90
12	ESTIMATED DESIGN DAY LOAD FACTOR	100%	22.35%	24.81%	52.95%	50.42%	0.00%	87.79%	38.13%
13	INCR CAPACITY MAIN INVESTMENT PER THERM	0.152883	$ 0.684040	$ 0.616215	$ 0.288731	$ 0.303219	$ -	$ 0.174146	$ 0.400952
14	2016 AVERAGE THERMS PER CUSTOMER	.	563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
15	CAPACITY MAIN INVESTMENT		$ 385.11	$ 1,437.01	$ 15,961.04	$ 34,437.18	$ -	$ 425,351.54	$ 443,180.27
16	INCR COMMODITY MAIN INVESTMENT PER THERM		0.540957	$ 0.540957	$ 0.540957	$ 0.540957	$ 0.540957	$ 0.540957	$ 0.540957
17	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
18	COMMODITY MAIN INVESTMENT		$ 304.56	$ 1,261.51	$ 29,904.11	$ 61,437.58	$ 15,537.37	$ 1,321,285.66	$ 597,930.75
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 4,077.60	$ 18,930.81	$ 70,708.41	$ 133,096.02	$ 34,748.15	$ 1,781,770.32	$1,179,349.92
20	LEVELIZED PLANT COST FACTOR	58 yr life	0.1763	0.1763	0.1763	0.1763	0.1763	0.1763	0.1763
21	ANNUAL REVENUE REQUIREMENT		$ 718.88	$ 3,337.50	$ 12,465.89	$ 23,464.83	$ 6,126.10	$ 314,126.11	$ 207,919.39
	UNDERGROUND STORAGE INVESTMENT								
22	BALANCING INVESTMENT PER TOTAL THROUGHPUT THERM		$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839	$ 0.005839
23	STORAGE INVESTMENT PER JANUARY SALES THERM		$ 0.381926	$ 0.381926	$ 0.381926	$ 0.381926	$ 0.381926		
24	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
25	2016 AVERAGE JANUARY SALES THERMS PER CUSTOMER		94	379	5,531	11,484	659		
26	UNDERGROUND STORAGE INVESTMENT		$ 39.19	$ 158.37	$ 2,435.23	$ 5,049.22	$ 419.41	$ 14,262.51	$ 6,454.32
27	LEVELIZED PLANT COST FACTOR	48 yr life	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
28	ANNUAL REVENUE REQUIREMENT		$ 6.91	$ 27.90	$ 429.09	$ 889.67	$ 73.90	$ 2,513.05	$ 1,137.25
29	TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER		$ 1,177.99	$ 3,940.20	$ 15,287.01	$ 28,816.57	$ 8,681.84	$ 326,283.99	$ 217,746.52

Exhibit No. 801
Miller / Avista
Page 2 of 3

Staff's LRIC Results and Rate Spread Given Main Extension Updates and No Schedule Decreases

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

RESULT SUMMARY *(Component Allocation)*

Line No.				OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS										
1	2016 ANNUAL THERM DELIVERIES			131,581,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
2	2016 CUSTOMERS			98,647	87,065	11,416	83	35	9	3	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER				563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4	Gas Commodity Costs		$	-	-	-	-	-	-	-	-
5	Gas Supply Department (Scheduling)	1.03189	$	56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)		$	142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading		$	116,123	102,489	13,439	98	41	11	4	42
8	Billing		$	2,437,937	2,151,696	282,139	2,051	865	222	74	890
	Customer Installation Investment Cost										
9	Meters		$	4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
10	Services		$	41,791,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	260,891
11	Main Extensions		$	86,193,139	52,003,034	32,670,464	363,529	229,674	30,482	18,582	877,375
12	Total Customer Installation Investment Cost		$	132,845,281	91,374,354	39,232,468	562,068	385,846	52,818	47,516	1,190,210
	System Core Main Cost										
13	Capacity		$	12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14	Commodity		$	12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost		$	24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost		$	1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost		$	161,470,329	104,922,344	45,335,716	1,280,937	1,018,121	78,931	981,347	7,852,933
18	**Distribution Margin Revenue at Present Rates**		$	**53,224,000**	**34,864,000**	**13,605,000**	**687,000**	**463,000**	**44,000**	**231,000**	**3,330,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components										
19	Cost of Gas Commodity		$	-	-	-	-	-	-	-	-
20	Gas Supply Department Costs		$	568,000	303,900	165,043	28,446	24,644	1,603	6,899	37,466
21	Meter Reading, Billing, Etc. Costs		$	3,686,000	3,253,222	426,575	3,101	1,308	336	112	1,345
22	Meters & Services Costs		$	18,599,000	15,696,325	2,616,101	79,152	62,262	8,905	11,535	124,719
23	System Core Main Costs		$	37,367,000	21,064,405	12,823,153	348,218	276,398	18,556	317,158	2,519,112
24	Underground Storage Costs		$	1,561,000	906,149	480,161	53,680	46,934	1,002	11,364	61,709
25	**LRIC Based Target Margin**		$	**61,781,000**	**41,224,001**	**16,511,033**	**512,598**	**411,546**	**30,402**	**347,068**	**2,744,351**
26	Current Distribution Margin Revenue to Proposed Cost			**0.86**	**0.85**	**0.82**	**1.34**	**1.13**	**1.45**	**0.67**	**1.21**
27											
28	**Component LRIC Target Increase by Schedule: Staff's Results**		$	8,557,000	$ 6,360,001	$ 2,906,033	$ (174,402)	$ (51,454)	$ (13,598)	$ 116,068	$ (585,649)
	Margin Revenue Increases Assuming Application Revenue Requirement: Staff's Results										
29	LRIC Target Increase as a Percent of Present Distribution Margin Revenue -- **Updated Main Extensions**			**16.077%**	**18.2%**	**21.4%**	**-25.4%**	**-11.1%**	**-30.9%**	**50.2%**	**-17.6%**
30	**Target Increase as a % of Present Distribution Margin Rev. -- Updated Main Extensions**			**16.077%**	**16.8%**	**19.9%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
31	**Component Target Margin Increase by Schedule -- Updated Main Extensions**		$	8,557,000	5,855,097	2,701,903	-	-	-	-	-
32a	Purchased Gas Cost (Schedule 461 -- per therm)				$ 0.62069	$ 0.62069	$ 0.62069	$ 0.41155	$ 0.62069	N/A	N/A
32b	Purchased Gas Revenues		$	**51,593,477**	**$ 30,425,567**	**$ 16,523,642**	**$ 2,847,900**	**$ 1,635,921**	**$ 160,447**		
33	Total Billed Revenues (Excluding Adjustment Schedules 462, 476, 478, 493, 497)		$	**113,374,477**	**$ 71,144,664**	**$ 32,830,545**	**$ 3,534,900**	**$ 2,098,921**	**$ 204,447**	**$ 231,000**	**$ 3,330,000**
34	**Billed Revenues Percentage Increase/Decrease**			8.2%	9.0%	9.0%	0.0%	0.0%	0.0%	**N/A**	**N/A**

Staff's LRIC Results and Rate Spread Given Main Extension Updates and **Three Schedules With Decreases**

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

RESULT SUMMARY ***(Component Allocation)***

Line No.				OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS										
1	2016 ANNUAL THERM DELIVERIES			131,581,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
2	2016 CUSTOMERS			98,647	87,065	11,416	83	35	9	3	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER				563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4	Gas Commodity Costs		$	-	-	-	-	-	-	-	-
5	Gas Supply Department (Scheduling)	1.03189	$	56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)		$	142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading		$	116,123	102,489	13,439	98	41	11	4	42
8	Billing		$	2,437,937	2,151,696	282,139	2,051	865	222	74	890
	Customer Installation Investment Cost										
9	Meters		$	4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
10	Services		$	41,791,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	260,891
11	Main Extensions		$	86,193,139	52,003,034	32,670,464	363,529	229,674	30,482	18,582	877,375
12	Total Customer Installation Investment Cost		$	132,845,281	91,374,354	39,232,468	562,068	385,846	52,818	47,516	1,190,210
	System Core Main Cost										
13	Capacity		$	12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14	Commodity		$	12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost		$	24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost		$	1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost		$	161,470,329	104,922,344	45,335,716	1,280,937	1,018,121	78,931	981,347	7,852,933
18	**Distribution Margin Revenue at Present Rates**		**$**	**53,224,000**	**34,864,000**	**13,605,000**	**687,000**	**463,000**	**44,000**	**231,000**	**3,330,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components										
19	Cost of Gas Commodity		$	-	-	-	-	-	-	-	-
20	Gas Supply Department Costs		$	568,000	303,900	165,043	28,446	24,644	1,603	6,899	37,466
21	Meter Reading, Billing, Etc. Costs		$	3,686,000	3,253,222	426,575	3,101	1,308	336	112	1,345
22	Meters & Services Costs		$	16,599,000	15,696,325	2,616,101	79,152	62,262	8,905	11,535	124,719
23	System Core Main Costs		$	37,367,000	21,064,405	12,823,153	346,218	276,398	18,556	317,158	2,519,112
24	Underground Storage Costs		$	1,561,000	906,149	480,161	53,680	46,934	1,002	11,364	61,709
25	**LRIC Based Target Margin**		**$**	**61,781,000**	**41,224,001**	**16,511,033**	**512,598**	**411,546**	**30,402**	**347,068**	**2,744,351**
26	Current Distribution Margin Revenue to Proposed Cost			**0.86**	**0.85**	**0.82**	**1.34**	**1.13**	**1.45**	**0.67**	**1.21**
27											
28	Component LRIC Target Increase by Schedule		$	8,557,000	$ 6,360,001	$ 2,906,033	$ (174,402)	$ (51,454)	$ (13,598)	$ 116,068	$ (585,649)

Margin Revenue Increases Assuming Application Revenue Requirement

Line No.			OREGON TOTAL	SCH 410	SCH 420	SCH 424	SCH 440	SCH 444	SCH 447	SCH 456
29	LRIC Target Increase as a Percent of Present Distribution Margin Revenue - - **Updated Main Extensions**		**16.077%**	**18.2%**	**21.4%**	**-25.4%**	**-11.1%**	**-30.9%**	**50.2%**	**-17.6%**
30	**Target Increase as a % of Present Distribution Margin Rev. -- Updated Main Extensions**		**16.077%**	**16.8%**	**19.9%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
31	**Component Target Margin Increase by Schedule -- Updated Main Extensions**	$	8,557,000	5,855,097	2,701,903	-	-	-	-	-

Margin Revenue Increases Assuming Slightly Less Than Half the Applied for General Increase

Line No.			OREGON TOTAL	SCH 410	SCH 420	SCH 424	SCH 440	SCH 444	SCH 447	SCH 456
32	Target Increase	**$**	**4,150,000**							
33	**Target Increase as a % of Present Distribution Margin Rev. - - Updated Main Extensions**		**7.8%**	**8.7%**	**10.3%**	**-7.0%**	**0.0%**	**-7.0%**	**0.0%**	**-7.0%**
34	**Component Target Margin Increase by Schedule -- Updated Main Extensions**	$	4,150,000	3,034,133	1,400,137	(48,090)	-	(3,080)	-	(233,100)
35	Purchased Gas Cost (Schedule 461 -- per therm)			$ 0.62069	$ 0.62069	$ 0.62069	$ 0.41155	$ 0.62069	N/A	N/A
36	Purchased Gas Revenues	**$**	**51,593,477**	**$ 30,425,567**	**$ 16,523,642**	**$ 2,847,900**	**$ 1,635,921**	**$ 160,447**		
37	Total Billed Revenues (Excluding Adjustment Schedules 462, 476, 478, 493, 497)	**$**	**108,967,477**	**$ 68,323,700**	**$ 31,528,778**	**$ 3,486,810**	**$ 2,098,921**	**$ 201,367**	**$ 231,000**	**$ 3,096,900**
38	**Billed Revenues Percentage Increase/Decrease**		4.0%	4.6%	4.6%	-1.4%	0.0%	-1.5%	**N/A**	**N/A**

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10/8/2015

CASE: UG 288
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1304

Exhibits in Support
Of Opening Testimony

October 16, 2015

Average Residential Customer Burden from Selected 7% Industrial Rate Reductions

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended December 31, 2016
(000s of Dollars)

Table's Origin: Exhibit AVISTA/903, Ehrbar/Page 3 of 4

Line No.	Type of Service	Schedule Number	Distribution Revenue Under Present Rates	Proposed GRC Increase	Distribution Revenue Under Proposed Rates	Therms (000s)	**Distribution/ Margin Revenue Percentage Increase**	Billed Revenue Under Present Rates	Proposed GRC Increase	Billed Revenue Under Proposed Rates	**Billed Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential	410	$34,864	$5,924	$40,788	49,019	**17.0%**	$66,399	$5,924	$72,323	**8.9%**
2	General Service	420	13,605	2,917	16,522	26,621	**21.4%**	30,571	$2,917	$33,488	**9.5%**
3	Large General Service	424	687	(48)	639	4,588	**-7.0%**	3,611	($48)	$3,563	**-1.3%**
4	Interruptible Service	440	463	0	463	3,975	**0.0%**	2,307	$0	$2,307	**0.0%**
5	Seasonal Service	444	44	(3)	41	258	**-7.0%**	209	($3)	$206	**-1.5%**
6	Transportation Service	456	3,330	(233)	3,097	39,792	**-7.0%**	3,384	($233)	$3,151	**-6.9%**
7	Special Contract	447	231	0	231	7,327	**0.0%**	231	$0	$231	**0.0%**
8	Total		$53,224	$8,557	$61,781	131,581	**16.1%**	$106,712	$8,557	$115,269	**8.0%**

Derivations:

1. Number of residential customers (from Exhibit No. 801, Miller/Avista, Page 1 of 3):	87,065
2. Revenue shift (x1000) from 7% reduction for Sch's 424, 444, and 456 -- i.e., .07 x (639 + 41 + 3,097):	$264
3. Per-thousand-therm price addition to Sch's 410 and 420 from 7% revenue shift -- i.e., $264/(49,019 + 26,621):	$0.0035
4. Burden (x1000) to Sch 410 from per-thousand-therm price addition -- i.e., $0.0035 x 49,019:	$171
5. Average annual burden per-customer in Sch 410 from selected 7% margin revenue shift -- i.e., ($171 x 1000)/87,065:	**$1.97**
6. Sch 410 current annual average bill -- i.e., ($66,399 x 1000)/87,065:	$763
7. Average annual burden per-customer in Sch 410 as a percentage of the annual bill, i.e., $1.87/$763:	0.3%

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Service List (Parties)

EDWARD FINKLEA **(C)** EXECUTIVE DIRECTIOR	326 FIFTH ST LAKE OSWEGO OR 97034 efinklea@nwigu.org
AVISTA CORPORATION	
	1411 EAST MISSION PO BOX 3727 SPOKANE WA 99220-0500 dockets@avistacorp.com
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PUBLIC UTILITY COMMISSION OF OREGON	
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PUC STAFF--DEPARTMENT OF JUSTICE	
MICHAEL T WEIRICH **(C)**	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 michael.weirich@state.or.us

CERTIFICATE OF SERVICE

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I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding through Huddle.

Dated this 16th day of October , 2015 at Salem, Oregon

Mark Brown
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (503) 378-8287