Oregon
Kate Brown, Governor

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July 31, 2015

Via Electronic Filing and US Mail

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

RE: Docket No. UG 287 – In the Matter of CASCADE NATURAL GAS CORPORATION, Request for a General Rate Revision.

Enclosed for filing is Staff Opening Testimony in UG 287, together with a Certificate of Service and UG 287 Service List.

Exhibits 703, 806 and 808 are confidential. A copy of the confidential exhibits were mailed today to parties who have signed Protective Order No. 15-094.

Exhibits 603, 704 and 705 are excel spreadsheets and are filed as electronic only.

/s/ Kay Barnes
Utility Program
(503) 378-5763
Email: kay.barnes@state.or.us

CASE: UG 287
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

July 31, 2015

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

A. My name is Marianne Gardner. I am a Senior Revenue Requirement Analyst employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (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/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 Cascade Natural Gas's (CNG's or Company's) filing in this docket, identified as UG 287. As such, I verify CNG'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 CNG's revenue requirement.

Additionally, I provide background regarding specific issues I reviewed, my analysis, and my recommendations.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 102	Uncollectible Charts
Exhibit 103	Uncollectibles
Exhibit 104	Wages and Salaries

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

A. Yes. Each Staff assigned to UG 287 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. 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

Cascade Natural Gas
UG 287
2015 General Rate Case
Staff General Assignments

Issue No.	Exh. No.	Staff's Rev. Req. Model Adj. No.	Description	Staff witness	Rev.	Exp.	Rate Base	Revenue Requirement
					Staff Proposed 2015 Test Year Adjustments $000's			
Issue-1 MG	100	S-1	Uncollectibles	Marianne Gardner	$0	($224)	$0	($242)
Issue-2 MG	100	S-2	Workforce Levels, Salaries and Wages, Incentives	Marianne Gardner		(216)	(52)	(228)
Issue-3 MG	100	S-3	Amortization	Marianne Gardner				
Issue-4 MG	100		State Income Tax, Federal Income Tax, and Accumulated Deferred Income Tax	Marianne Gardner				
Issue-5 MG	100		Working Capital	Marianne Gardner				
Issue-6 MG	100	S-4	Director Fees	Marianne Gardner				
Issue-1 SB	200	S-5	Sales Forecast & Revenue Adjustment	Suparna Bhattacharya	509	13		(509)
Issue-2 SB	200		Decoupling Mechanism	Suparna Bhattacharya				
Issue-1 MSB	300		Miscellaneous operating revenues	Max St. Brown				
Issue-1 EC	400	S-6	Gas Storage	Erik Colville			(17)	(2)
Issue-2 EC	400	S-7	Other Gas Supply Expense	Erik Colville		(4)		(5)
Issue-3 EC	400		Underground Storage Expense	Erik Colville				
Issue-4 EC	400		Purchased Gas	Erik Colville				
Issue-5 EC	400		IRP	Erik Colville				

Issue-1 LW	500	S-8	Distribution O&M expense (Non-labor)	Linnea Wittekind		(206)		(211)
Issue-2 LW	500		Customer accounting (Non-labor)	Linnea Wittekind				
Issue-2 LW	500		Customer Service & Informational and Sales Expenses (non-labor)	Linnea Wittekind				
Issue-2 LW	500		Gains on sales of utility property	Linnea Wittekind				
Issue-2 LW	500		Taxes other than income	Linnea Wittekind				
Issue-2 LW	500		Materials and Supplies - Non-fuel	Linnea Wittekind				
Issue-2 LW	500		Prepaid expenses	Linnea Wittekind				
Issue-1 MPM	600	S-9	Advertising, marketing, promotional activities and concessions (Non-labor)	Mitch P. Moore		(96)		(98)
Issue-1 BB	700	S-10	Pensions	Brian Bahr			(2,873)	(316)
Issue-2 BB	700	S-11	Medical Benefits	Brian Bahr		(1,060)		(1,088)
Issue-3 BB	700		Affiliated interest charges	Brian Bahr				
Issue-4 BB	700	S-12	Administrative & General expenses (Non-labor)	Brian Bahr		(810)		(831)
Issue-5 BB	700	S-13	Utility Plant in service, Plant Additions, Property Tax	Brian Bahr		(102)	(6,876)	(860)
Issue-1 MM	800		Capital Structure	Matt Muldoon				
Issue-2 MM	800		Cost of Equity					
Issue-3 MM	800		Cost of LT Debt	Matt Muldoon				
Issue-4 MM	800		Overall Rate of Return					
Issue-5 MM	800	S-14	Allocations and Multijuristictional Agreements	Matt Muldoon		(100)	(40)	(107)
Issue-1 GC	900		Mains LRIC	George Compton				
Issue-2 GC	900		Rate spread and rate design	George Compton				
Issue-3 GC	900		Tariff filing verification	George Compton				
Issue-1 JJ	1000	S-15	IT Costs/Rate base	Judy Johnson			(185)	(20)
Issue-2 JJ	1000		Pipeline Safety Cost Recovery	Judy Johnson				
Issue-3 JJ	1000	S-16	Environmental Remediation Cost Recovery	Judy Johnson		(369)		(379)
Issue-1 MP	1100	S-17	Depreciation	Ming Peng				
Grand Total					**$509**	**($3,175)**	**($10,044)**	**($4,895)**

Part 2, Specific Issues

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

A. I reviewed the portions of the filing related to uncollectible expense, workforce levels, wages and salaries, incentives, amortization 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 40 data requests, and reviewed the Company's responses to my data requests and multiple data requests in these areas submitted by other Staff and 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 B, Staff Issue Summary.

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 $540,518 as uncollectible expense in its test year revenue requirement. According to the workpapers accompanying the Company's initial filing, the Company recalculated the uncollectible rate for the test year based on a three-year average (2012-2014) of net write offs to general revenues.[2] The average of uncollectible expense in 2012, 2013, and 2014 is more than double ($278,894 higher) than the actual 2014 base year uncollectible expense of $261,624.[3] Whereas the 2014 average uncollectible rate is 0.398 percent, ($261,624/ $65,785,175), the test year rate is significantly higher at 0.771 percent.

During my review of Mr. Parvinen's workpapers, I noted the 2012 net write-offs of $784,554 were significantly higher than those in 2013 and 2014, $369,764 and $420,354, respectively. I issued additional data requests to determine if the net write-off amounts included bad debts unrelated to utility customer accounts. The Company responded in DR No. 254 (a) that, "[n]et write-offs in 2012 were significantly higher primarily as a result of developer commitment contract defaults. There were numerous developers who began projects in 2010 & 2011 that defaulted on their part of the commitments that were subsequently written off in 2012".[4]

Additionally, in its response to DR No. 255, the Company explained the net write-off amounts provided in Parvinen workpapers were averages for the

[2] Excel workbook, Copy of Parvinen Workpapers Exhibits 301 – 304.xlsx.
[3] CNG/300, Parvinen/5 at lines 1-6 and CNG/304/Parvinen/1 at line 13.
[4] Staff Exhibit 102, CNG Response to Staff DR No. 254.

year rather than annual amounts.[5] In response to DR No. 154, CNG provided the Oregon share of actual annual net write-offs for the years 2011 through 2014, $428,058, $663,822, $242,132, and $303,729, respectively.[6]

I utilized the actual annual net write-off amounts to trend the uncollectible rate as shown in Exhibit Staff/102, Chart 1. I then excluded the 2012 data from the uncollectible rate calculation in Chart 2. The resulting three-year average of 2011, 2013, and 2014 is 0.478 percent. I believe this is a more reasonable forecast.

My belief is supported by the Company's response to Staff's DR No. 257, which states, "Cascade's percentage of net write-offs over the previous five years is .51% as compared to the .45% previously reported in DR #163."[7] I note that if 2012 were excluded from CNG's calculation of the five-year average, the rate would be 0.44 percent.[8] Also, the Company's projected 2015 and 2016 rates are 0.48 percent and 0.46 percent respectively.[9]

Based on this analysis, I conclude 2012 data should not be used to determine the appropriate revenue requirement for uncollectible expense because the inclusion of developer's bad debt makes the uncollectible expense in that year anomalously high. While I agree with Cascade that the revenue requirement amount should be based on a three-year average, I replace 2012 data with 2011 data and use yearly actual amounts rather than yearly

[5] Staff /103, Cascade Response to Staff Data Request No. 255.
[6] Staff/103, Cascade Response to Staff Data Request No. 255.
[7] Staff/103, Cascade Response to Staff Data Request No. 257.
[8] Based on yearly amounts provided by Cascade in DR No. 257, "Credit Analysis – Year to Year Comparison."
[9] Staff/103, "Credit Analysis – Year to Year Comparison."

averages. The resulting percentage, 0.478 percent, is in line with Cascade's five-year average and with Cascade's estimates for 2015 and 2016.

I recommend that the forecasted test year uncollectible rate be adjusted to Staff's three-year average of 0.478 percent. Consequently, I will substitute the Uncollectible Accounts amount of 0.00771 found in Exhibit CNG/303/Parvinen/1 with .00478 in Staff's Revenue Requirement model. Likewise, applying the 0.478 percent rate to the Company's test year Natural Gas Sales, will cause the test year uncollectible expense to decrease $224,332 from CNG's proposed $540,518 to $316,186.

Issue 2: Workforce Levels, Salaries and Wages, Incentives

The Commission typically uses Staff's three-year wage and salary model (W&S model or Staff's model) to estimate expenses for non-union wages and salaries.[10] The increases in payroll from the historic base year should be tied to the rate of inflation using the All-Urban CPI.[11] I applied this model to the information the Company provided in its filing and responses to Staff's data requests. I did insert union payroll in the model also. Rather than using All-Urban CPI, the Commission in the past has ordered that union payroll increases be tied to negotiated wage increases as set forth in the union contract.[12] CNG was in negotiations with the union at the time of CNG's general rate case filing. Once CNG and the union release the new contract, I will update the union escalation factors in Staff's model.

[10] See e.g., Order No. 01-787.
[11] See Order 01-787 at 40; Order 99-697 at 43; Order 99-033 at 61; Order 95-322 at10.
[12] See Order 99-697 at 43.

As explained by Mr. Parvinen, the Company base year is 2014 actual Oregon booked amounts.[13] The Company proposed a series of adjustments to this base year culminating in the 2015 test year amounts. I have listed CNG's modifications affecting workforce levels, salaries and wages, and incentives below. Each pertinent adjustment is assigned the letter ascribed in Mr. Parvinen's Exhibit 304, as well as the related increase or (decrease) in labor expense.[14]

1. (c) "Officer Incentive Com. Adj." ($135,107)
2. (g) "Annualizing Wage Rate Adjustment" $25,051
3. (k) "2015 Wage Adjustments" $175,389
4. (m) "Labor Additions Adjustment" $590,631
5. (t) "Employee Incentive Plan Adj." ($112,104).

CNG's adjustment (c) conforms to Commission policy that disallows 100 percent of officers' bonuses because they are based on increased earnings.[15] Adjustment (t) reduces expense for employee incentives. It is 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.[16] The Company reduced financial performance incentives for employees other than officers by 100 percent.

[13] CNG/300, Parvinen/3 at 9-15.
[14] CNG/304, Parvinen/ 1at (c), (g), (j) and CNG/304/Parvinen/2 at (m) and (t).
[15] See Order 99-033 at 62; Order 97-171 at 74-76.
[16] See Order 99-697 at 44-45; Order 99-033 at 62.

Therefore, in Staff's W&S model, I modified the financial performance adjustment to reflect 75 percent per Commission policy.

The remaining adjustments (g), (k) and (m) all are incorporated in Staff's W&S model. Full-time equivalents (FTE) in the model are based on Cascade's Oregon share of FTE provided by the Company in DR No. 180 revised.[17] My proposed adjustment is broken down as a decrease to O&M expense of $216,431 and $52,499. The supporting calculations for my adjustment can be found in Staff's electronic workpaper entitled UG 287 S-2 Wages and Salaries.xlsx.

S-3: Amortization Expense

The Company did not include in their initial filing any testimony or exhibits that support intangible rate base or amortization expense for the 2014 base year or the 2015 test year. Therefore, I issued DR Nos. 2016-2015 requesting this information. I ensured that the detail provided agreed to the balances in the 2014 ROO and the 2015 test years. I also shared these data responses with other Staff witnesses who are reviewing amortization rates and intangible plant additions.

As the Revenue Requirement Summary Witness, I will update the test year amortization expense and reserves to reflect adjustments sponsored by other Staff witnesses to the amortization rates or intangible plant. Therefore, while I do not propose any adjustment at this time to amortization expense or the reserve account, I may have an adjustment to the final revenue

[17] Staff Exhibit 104, CNG Response to Staff DR No.180.

requirement contingent on other Staff witnesses associated discovery and analysis.

S-4: SIT, FIT and ADIT

The Company's proposal for the test year state and federal income tax expense is $1,513,329.[18] This is a reduction of $885,808 from the 2014 Results of Operations (ROO) income tax; the incremental tax effect of the Company's adjustments to 2014 ROO based on the federal and Oregon statutory income tax rates of 35 percent and 7.6 percent, respectively. CNG has based the revenue sensitive amount for state and federal income tax on these statutory rates.[19] The resulting conversion factor or net-to-gross factor is used to calculate the incremental revenue requirement. As confirmed in subsequent data requests, the amount of income taxes included in the 2014 ROO are estimated taxes based on 2014 provisions.

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. According to IRC Sec. 168(i)(9),

> ***"(9) Normalization rules***
>
> ***(A) In general***
>
> *In order to use a normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—*

[18] CNGC/301, Parvinen/1 at 17, column (3).
[19] CNG/300, Parvinen/4 at 15-20 and CNG/303, Parvinen/1.

(i)*the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and*

(ii)*if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference."* Also, 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 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."*

In addition to reviewing the Company's responses to Staff's Standard DRs, I issued a number of additional data requests to ascertain whether the Company normalized federal income taxes are consistent with Commission policy and whether the amount of taxes included in the rate case are fair and reasonable. To this end, I reviewed the components and calculations of current taxes, deferred taxes, the related ADIT, and the Company's jurisdictional allocation between Oregon and Washington. As part of my analysis, I reviewed the Company's calculations for the taxes included in the

2014 ROO, the filed Oregon Corporation Excise Tax Return, and Form 20 for years 2003 through 2013. I asked the Company to explain the differences in the Oregon state effective tax rate based on the Form 20 as compared to its filed ROO for the years 2011-2014. I also, spoke to Mr. Parvinen regarding normalization of state taxes and the related deferred taxes in rate base. According to Mr. Parvinen, the Company did normalize state taxes and the related deferred taxes for the 2015 test year. The Company's formal response is still pending. As of this time, I do not anticipate adjusting the Company's base year income tax expense nor the proposed federal or state effective tax rates included in the Company's revenue sensitive factors as listed in Exhibit CNG/303/Parvinen/1.

S-5: Working Capital

The Company included $5,071,649 in its test year working capital allowance. This includes, FERC Accounts No. 154, Plant Material and Operating Supplies; No. 163, Store Expense Undistributed; No. 164.2, Liquefied Natural Gas Stored, and No. 165, Prepayments.

The Commission's long-standing policy has been to exclude working capital from rate base for gas utilities. However, Staff stipulated to allowing Avista, in the two most recent Avista rate cases UG 246 and UG 284, to include in rate base costs from FERC Account Nos. 154, 163, and 164.2. The Commission adopted those stipulations. Therefore, I recommend the same treatment in UG 287. Staff witness Erik Colville reviewed the amount included in rate base, and his conclusions can be found in his testimony.

The prepayment amount (FERC Account No. 165) included in rate base is predominately for prepaid pension. Staff witness, Brian Bahr, offers testimony regarding the rate base treatment of this component.

<u>S-6: Director Fees</u>

According to OARs 860-034-0500 and 860-027-0016, “Director fees paid by a public utility to members of its board of directors, who are also paid as officers of the utility, shall not be recognized as a charge to operating expenses in Oregon.” I have issued a data request to CNG to determine whether any unallowable portion of director fees is included in the 2015 test year. Cascades’ response is still pending.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 287
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

July 31, 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, and UG 284.

I have approximately 20 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.

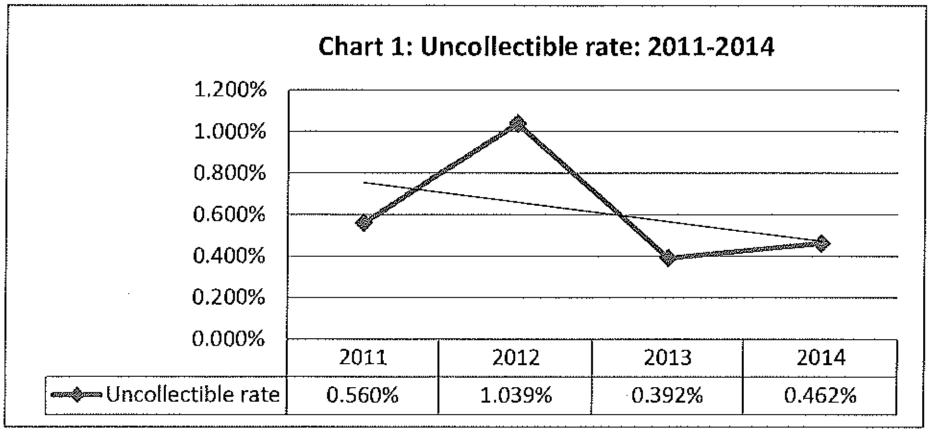
CASE: UG 287
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION OF OREGON

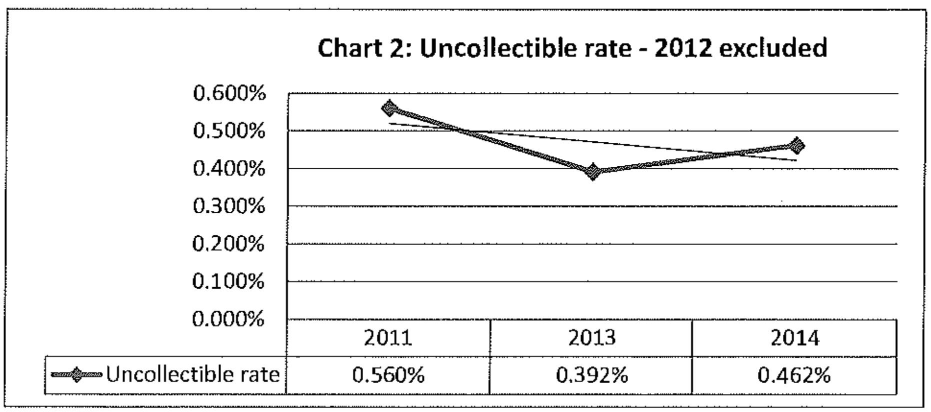
STAFF EXHIBIT 102

Exhibits in Support Of Opening Testimony

July 31, 2015



Actuals [1]	2011	2012	2013	2014	Four Year Average
Net Write Offs	428,058	663,822	242,132	303,729	409,435
Gen. Bus. Rev. (Natural Gas Sales)	76,397,481	63,890,532	61,777,272	65,758,175	66,955,865
Uncollectible rate	0.560%	1.039%	0.392%	0.462%	0.612%



Actuals [1]	2011	2013	2014	Three Year Average
Net Write Offs	428,058	242,132	303,729	324,640
Gen. Bus. Rev. (Natural Gas Sales)	76,397,481	61,777,272	65,758,175	67,977,643
Uncollectible rate	0.560%	0.392%	0.462%	0.478%

[1] Provided by Company in Response to Staff DR 254. Staff/103/Gardner/1

CASE: UG 287
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

July 31, 2015

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 254

Date prepared: 6/25/2015

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)734-4591

254. Referring to the Company's response to Staff's DR No. 154 a., the Company provided the information listed in Table A below, regarding Oregon uncollectible customer accounts, the related general business revenues, and the uncollectible rate. Referring to Table A, please explain the following:

a. Why are the 2012 net write-offs and the uncollectible rate significantly higher than 2011, 2013, and 2014?

b. What bad debt expense types are included in the net write-off amounts? For example, in addition to uncollectible customer accounts, are other losses such damaged equipment and uninsured losses included?

Table A

Actuals	2011	2012	2013	2014
Net Write Offs	$428,058	$663,822	$242,132	$303,729
Gen. Bus. Rev.	$76,397,481	$63,890,532	$61,777,272	$65,758,175
Uncollectible Rate	0.53%	1.04%	0.39%	0.46%

c. Referring to (b) above and UE 294/CNGC/301, Parvinen/1 at 10, Customer Accounts, please explain whether the Company has included bad debt expense in FERC account 904, which does not directly arise from or is not directly correlated to retail revenue associated with utility customer billings.

d. Referring to (c) above, if the Company has included other types of bad debt expense, please summarize by bad debt expense type the amounts for each year 2011 through 2015, inclusive.

Response:

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

A) Net write-offs in 2012 were significantly higher primarily as a result of developer commitment contract defaults. There were numerous developers who began projects in 2010 & 2011 that defaulted on their part of the commitment which were subsequently written off in 2012.

B) Bad debt expense is entirely from utility customer accounts.

C) See response to (B) above Cascade's bad debt expense is entirely from utility customer accounts.

D) See responses to (B) & (C) above. N/A

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 255

Date prepared: June 25, 2015

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)734-4591

255. Referring to Table A in Staff's above DR No. 254, and UG 287/ CNG/303, Parvinen/ 1 of 1, please explain why the net write offs amounts and the total operating revenue amounts provided in Exhibit 303 differ, for each year, from the data provided by the Company in DR No. 154 a.

Response:

Table A as reported in DR 154

Actuals	2011	2012	2013	2014
Net Write Offs	$428,058	$663,822	$242,132	$303,729
Gen. Bus. Rev.	$76,397,481	$63,890,532	$61,777,272	$65,758,175
Uncollectible Rate	0.53%	1.04%	0.39%	0.46%

Table A as revised to include total revenue not just row 1 (Natural Gas Sales) on the ROO.

Actuals	2011	2012	2013	2014
Net Write Offs	$428,058	$663,822	$242,132	$303,729
Gen. Bus. Rev.	$80,606,310	$68,132,016	$65,973,538	$70,092,488
Uncollectible Rate	0.53%	0.97%	0.37%	0.43%

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Table A should be revised as stated above. Only row 1 of the annual ROO was included in the revenue total. This changes the uncollectible rate to be slightly lower that originally reported in DR 154.

The uncollectible rate as computed in CNG/303 is a three year average. The figures used in DR 154 were annual amounts not averaged.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 163

Date prepared: 7/14/15

Preparer: Mike Kingery

Contact: Pamela Archer

Telephone: (509)734-4591

163. Please provide CNG's written policy regarding uncollectible accounts. If a written policy does not exist, please describe the steps and procedures in the collection process. In addition to describing your general policy, please include specific responses to (a – g) below.

a. How does the Company determine that an account is uncollectible?
b. What attempts are made to recover the funds prior to turning the account over to a collection company? Please address in the response how the customer is contacted, number of times contacted, options provided to the customer for payment, additional fees and interest charged, and the timeframe;
c. What criterion is used for turning a delinquent account over to a collection agency?
d. What is the procedure for determining when delinquent accounts are disconnected?
e. What is the process for writing-off a bad debt from the accounting records? For example, what are the criteria used to determine an account is uncollectible, who authorizes the write-off of the bad debt in the accounting records, and what is the accounting entry?
f. What is the process for reinstating a customer account previously written-off, and what is the accounting entry?
g. Please provide any benchmarking comparing CNG's uncollectible rate to the natural gas industry.

Revised Response: See attached file A163_A.pdf

The attached policy (AD 112.0) outlines the internal policy for the write-off of uncollectible accounts. The policy indicates account balances should be written-off once the account becomes inactive and there are no active accounts that are eligible for the transfer of the balance. Once the account has been inactive for 90 days following the final bill due date, the balance is written-off as uncollectible.

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Prior to pursuing a company initiated turn-off, several attempts to contact the customer are made through various channels. That process includes an automated phone call, past due indication on the following bill, mailed notices, a manual phone attempt from a credit agent and field personnel knocking at the residence prior to disconnecting service.

Once the account has become inactive and a final bill is issued, three follow-up letters are sent in 30 day increments in an attempt to secure payment for the final balance. These letters are sent to customers that are inactive due to a company initiative turn-off (non-pay) and to customers that have a remaining balance from a turn-off that resulted in the customer requesting service off or a new tenant acquiring service. The account is also monitored for return mail in order to identify a potential forwarding address. Shortly following the third letter, the account is deemed uncollectible.

Once an account becomes uncollectible and is written-off, unpaid balances greater than $25 are assigned to a collection agency.

Active accounts that become past due are reviewed to determine if collection processes should begin, leading to service disconnection if the account remains unpaid. Past due balances over $100 are identified by the customer information system (CIS), triggering the collection process that begins with an automated notification phone call. Other factors such as the service start date, date and amount of last payment, and the aging of the debt are considered when prioritizing which accounts follow the process leading to disconnection.

Once the 90 days following the final bill date has elapsed, the customer information system (CIS) starts an automated process that moves the account to write-off staff and creates the necessary journal entries. Account balances over $5000 are not included in the automated process and must be reviewed manually by the Credit Manager prior to the write-off.

If the write-off needs to be reinstated, the amounts are adjusted in CIS and the account status is also adjusted accordingly.

Over the last five years, Cascade has averaged a Net Write-Off as a percentage of Revenue of 0.51%.

Accounting entries for writing off an uncollectible are debited to FERC account 144 and credited to FERC account 142.

Accounting entries for reinstating a customer account previously written-off are debited to FERC 131 and credited to FERC account 144.

CASE: UG 287
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

July 31, 2015

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 180

Date prepared: 7/22/15

Preparer: Kevin Conwell/Chris Ryan

Contact: Pamela Archer

Telephone: (509)734-4591

180. Referring to CNG's response A92, to Staff's SDR 92, please supplement the response and provide, for the Test year and the preceding 4 calendar years, the summary table information on an Oregon share basis. Please include the Capitalized salaries and wages and the O&M salaries and wages.

Year: 2015		Projected Actual (Unadjusted) Paid Cash Compensation			
Category	**Oregon Share** □FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$182,969.17	$0	$0	$182,969.17
Exempt	26	$2,177,617.90	$0	$181,624.94	$2,359,242.84
Nonexempt	9	$330,105.36	$53,050.45	$42,608.80	$425,764.62
Union	48	$2,980,036.68	$586,111.61	$14,751.74	$3,580,900.03
Total	83.25	$5,670,729.11	$639,162,06	$238,985.49	$6,548,876.66
□Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Oregon projected capitalized labor total is $1,709,392.62

CASCADE NATURAL GAS CORPORATION
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Year: 2014		Actual (Unadjusted) Paid Cash Compensation			
Category	**Oregon Share** □FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$177,218.92	$0	$135,272.27	$312,491.19
Exempt	25	$2.043,903.41	0	$266,150.15	$2,310,053.55
Nonexempt	8	$290,554.90	$53,050.45	$62,613.58	$406,218.93
Union	42	$2,675,108.87	$586,111.61	$21,672.78	$3,282,893.26
Total	75.25	$5,186,786.09	$639,162.06	$485,708.78	$6,311,656.93
□Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Oregon capitalized labor total for 2014 was $1,578,468.90

Year: 2013		Actual (Unadjusted) Paid Cash Compensation			
Category	**Oregon Share** □FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$175,345.42	$0	$34,338.16	$209,683.58
Exempt	24	$1,719,293.59	$0	$395,725.69	$2,115,019.29
Nonexempt	7	$304,218.17	$55,699.80	$9,705.78	$369,623.75
Union	41	$2,585,854.44	$549,732.83	$0	$3,135,587.26
Total	72.25	$4,784,711.62	$605,432.63	$439,769.64	$5,829,913.89
□Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Oregon capitalized labor total for 2013 was $1,415,118.07

CASCADE NATURAL GAS CORPORATION
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Year: 2012		Actual (Unadjusted) Paid Cash Compensation			
Category	**Oregon Share** □FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	.25	$161,273.49	$0	$59,653.29	$220,926.78
Exempt	20	$1,599,012.09	$0	$181,648.30	$1,780,660.39
Nonexempt	6	$273,109.50	$20,166.02	$18,625.46	$311,900.98
Union	42	$2,532,870.40	$510,518.75	$811.73	$3,044,200.87
Total	68.25	$4,566,265.48	$530,684.77	$260,738.78	$5,357,689.03
□Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Oregon capitalized labor total for 2012 was $1,463,513.05

Year: 2011		Actual (Unadjusted) Paid Cash Compensation			
Category	**Oregon Share** □FTE	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers	0	$116,550.06	$0	$90,227.90	$206,777.96
Exempt	22	$1,700,521.64	$0	$197,558.63	$1,898,080.26
Nonexempt	5	$225,914.71	$17,324.14	$49,389.66	$292,628.50
Union	40	$2,181,103.84	$395,155.30	$293.16	$2,576,552.31
Total	67	$4,224,090.25	$412,479.44	$337,469.34	$4,974,039.03
□Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

Oregon capitalized labor total for 2011 was $1,349,777.95

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Response: **See Excel file CNG OPUC DR A179-180_Revised_7_22.xlsx**

DR #180

Oregon Allocated				
Base Wages or Salaries				
Officers	177,218.92	175,345.42	161,273.49	116,550.06
Exempt	2,043,903.41	1,719,293.59	1,599,012.09	1,700,521.64
Nonexempt	290,554.90	304,218.17	273,109.50	225,914.71
Union	2,675,108.87	2,585,854.44	2,532,870.40	2,181,103.84
	5,186,786.09	4,784,711.62	4,566,265.48	4,224,090.25
Overtime				
Officers	0.00	0.00		
Exempt	0.00	0.00		
Nonexempt	53,050.45	55,699.80	20,166.02	17,324.14
Union	586,111.61	549,732.83	510,518.75	395,155.30
Incentive or Bonus				
Officers	135,405.87	34,341.00	59,823.52	91,668.69
Exempt	266,413.01	395,758.47	182,166.66	200,713.31
Nonexempt	62,675.42	9,712.58	18,678.61	50,178.33
Union	21,702.18	0.00	810.05	297.84
	486,196.49	439,812.06	261,478.83	342,858.17
Total O&M	6,312,144.64	5,829,956.31	5,358,429.08	4,979,427.86
Capitalized wages	1,578,468.90	1,415,118.07	1,463,513.05	1,349,777.95

DR #180 Projected 2015 Oregon Share of Salaries & Wages

		2015 Adjustments Exh. 304					
	2014 Actual	c) Officer Incentive Comp	g) Annualizing wage rate adj	j) 2015 Wage adjustments	m) labor additions adj	t) Employee incentive plan adj	2015 With Adjustments
Oregon Allocated							
Base Wages or Salaries							
Officers	177,218.92			5,750.25			182,969.17
Exempt	2,043,903.41			66,549.49	67,165.00		2,177,617.90
Nonexempt	290,554.90			9,460.47	30,090.00		330,105.36
Union	2,675,108.87		25,051.00	93,628.81	186,248.00		2,980,036.68
	5,186,786.09						5,670,729.11
Overtime							
Officers	0.00						
Exempt	0.00						
Nonexempt	53,050.45						53,050.45
Union	586,111.61						586,111.61
							639,162.06
Incentive or Bonus							
Officers	135,107.00	(135,107.00)					0.00
Exempt	266,711.88					(85,086.94)	181,624.94
Nonexempt	62,675.42					(20,066.62)	42,608.80
Union	21,702.18					(6,950.44)	14,751.74
	486,196.49						238,985.49
Total O&M	6,312,144.64	(135,107.00)	25,051.00	175,389.02	283,503.00	(112,104.00)	6,548,876.66

DR #180 requested salaries and wages only. The amount in exhibit 304 includes benefits.

CASE: UG 287
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

July 31, 2015

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

A. My name is Suparna Bhattacharya. 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/201.

Q. What is the purpose of your testimony?

A. This testimony presents Staff's analysis and recommendations regarding Cascade's sales forecast and decoupling mechanism.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Exhibits for this docket:

Exhibit Staff/201 Witness Qualification
Exhibit Staff/202 2015 Sales Forecast
Exhibit Staff/203 Revenue Adjustments
Exhibit Staff/204 Cascade responses to Data Requests

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. <u>Sales Forecast</u>: Based on the forecasts obtained from Staff's econometric models, Cascade's test year sales for core customers will increase by approximately 0.85%, relative to the 2014 actual sales. Higher sales initiate an increase in the test year revenue. The revenue increase from Staff's sales adjustments is $509,143.

2. Decoupling Mechanism: After analyzing two important components of the Company's current Conservation Alliance Plan (CAP) program – decoupling mechanism and public purpose charge (PPC), Staff proposes that the Commission,

   a. continue the current decoupling mechanism that tracks weather and conservation variances separately;
   b. revise the current CAP weather normalization adjustment methodology (tracking sales adjustments under normal weather), so that it is consistent with the normalization method used to determine forecasted sales in the current rate case;
   c. allow the Company to collect the total revenue provided to the Energy Trust of Oregon (ETO) and other Community Action Agencies (Agencies) for conservation programs from rate schedules 101, 104, 105, and 111 through the PPC tariff – Schedule 31. A direct line item surcharge on all customers' bills will result from this expansion. This would spread the costs associated with these programs across customers who participate and benefit from these programs; and
   d. remove the sunset date for the CAP program that is currently present in the tariff. By September 30, 2018, the Company, Staff and other interested parties should be required to review the CAP and file a report with the Commission recommending modifications and changes to the CAP, to be effective January 1, 2019, if any.

Issue 1, Sales Forecast

Q. Please summarize the Company's proposed sales forecast for the test year 2015.

A. The Company's total projected sales for residential, commercial, and industrial customers (core customers) is 74,229,686 therms, and projected test year sales for interruptible transportation customers (non-core customers) is 263,225,003 therms.[1] Compared to the 2014 actual therms, test year sales forecast is 0.63% higher for core customers and 7.6% higher for non-core customers.[2]

Q. Please explain the Company's proposed forecasting models that generated the 2015 sales forecast for the core customers.

A. Cascade developed linear regression models with monthly average sales as the response variable and monthly Heating Degree Days (HDD) as an explanatory variable.[3] Both these variables are at the city gate level.[4] There are in total 22 city gates that cover the energy demand for the Cascade service territory in Oregon, and thus 22 forecasting models, one for each city gate.[5] Each regression model is fitted to the actual data from January 2004 through December 2014, and the baseline sales forecast for the test year is generated by city gate.[6]

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1 CNG/601.
2 CNG/601.
3 CNG/400, Robinson/7-8.
4 CNG/400, Robinson/7.
5 Cascade/402, Robinson/1.
6 Cascade/400, Robinson/7-8.

The baseline sales forecasts are further adjusted to account for the effect of population growth on the customer demand.[7] The Company performed an outboard adjustment and derived the final sales forecast (growth adjusted) for each city gate.[8] The annual growth projections for the 2015 test year are collected from Woods and Poole.[9]

Finally, the Company assigned the 2015 adjusted monthly forecasted therms to all core rate schedules based on the historical demand usage pattern of the rate schedules at each city gate.[10] Specifically, the Company calculated the monthly allocation percentage as the energy demanded from a rate schedule by city gate and month over the total energy demanded from all rate schedules by city gate and by month.[11] Monthly allocations are estimated for each year beginning 2010 through 2014, and the average of the five-year monthly allocation percentage is used to assign the 2015 therms to each rate schedule.[12] The historical monthly usage information for each rate schedule is collected from the Company's Customer Care and Billing System (CC&B).[13]

To create the weather variable, the Company collects daily minimum and maximum temperature data by weather station from the Schneider Electric weather service and calculates the daily average temperature as the simple average of the high and low temperatures for each weather station.[14] Three

[7] Cascade/400, Robinson/3.
[8] Cascade/400, Robinson/6.
[9] Cascade/400, Robinson/6.
[10] Cascade/400, Robinson/9.
[11] Cascade/400, Robinson/9.
[12] Cascade/400, Robinson/9.
[13] Cascade/400, Robinson/4.
[14] Cascade/400, Robinson/4.

weather stations – Baker city, Pendleton, and Redmond were determined to best fit the Cascade's service territory in Oregon.[15] A particular weather station is assigned to each city gate primarily based on the proximity and quality of the data available at each weather station.[16] The daily average temperature is then subtracted from the heating degree day (HDD) threshold value of 60°F to create the HDD for a given day.[17] The average of daily HDDs calculated for each month is used as the weather variable. To create the response variable, the Company extracted monthly sales data by each city gate for the time period 2004 through 2014 from the pipeline Electronic Bulletin Board (EBB) system.[18]

Q. Please explain Staff's approach to analyze the test year sales forecast for the core customers.

A. Staff's goal is to ensure that the model-based sales forecast generated for the test year is robust and accurate based on the available data and applied econometric methodologies. The following steps describe Staff's forecasting procedures and model results:

Forecasting Procedures

a. Reviewed the Company's sales forecast methodology and models, associated work papers, and the Company's responses to Staff's ten data requests. Staff also had several rounds of discussions with the Company on load forecast issues.

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[15] CNG/400, Robinson/4.
[16] Cascade/401, Robinson/9.
[17] Cascade/400, Robinson/3.
[18] Cascade/400, Robinson/4.

b. Developed two sets of forecasting models for each city gate, the first set (A) with weather as the main forecast driver (comparable to the Company's base regression models) and, the second set (B) with weather and population as the forecast drivers (comparable to the Company's final adjusted forecast).

For both sets of models (A) and (B), Staff considered the Company's approach to identifying the HDD threshold value of 60°F and the Company's decision to substitute 60°F as the HDD threshold value for the 65°F value that Cascade has used historically. The Company asserts that sales demand in Cascade's service territories is more sensitive and correlated to 60°F than to threshold HDD value of 65°F.[19] The data for HDDs has been provided by the Company.[20] Staff also uses 60°F for the HDD threshold value.

For the second set of models (B), Staff included population as an exogenous variable in the model rather than adjusting the effect outside the econometric model. The annual historical and test year population data by county (assigned to each city gate) is from Woods and Poole database and provided by the Company.[21] Given that the population data is available for the historical time period (2004-2014) and correlated with demand, Staff asserts that the population effect can be directly captured by the econometric models.

[19] Staff/205, CNG Response to Staff Data Request 174.
[20] Staff/205, CNG Response to Staff Data Request 174.
[21] Staff/205, CNG Response to Staff Data Request 174.

Staff used the Company's response variable i.e., monthly sales by city gate for both sets of models. Sales data is provided by the Company.[22] Two sets of linear regression models are estimated for the time period 2004 - 2014 and test year sales predicted for all city gates.

c. Compared the performances of these two alternate sets of models for: a) the estimation period, where regression models are fitted to the actual data available from January 2004 through December 2014; and b) the validation period, where models are fitted to the data from January 2004 through December 2013 (the in-sample-period), and forecasts are generated for the period January 2014 through December 2014 (the out-of-sample period). Evaluated several statistical measures such as R-squared, adjusted R-squared, standard error of the regression, root mean squared error (RMSE), mean absolute percent error (MAPE), akaike info criterion (AIC), and schwarz criterion (SBC) for model comparisons.

d. Finally, assigned the forecasted therms generated at each city gate to residential, commercial and industrial rate schedules using the Company's allocation percentages. Since historical usage data by rate schedules prior to 2010 is not available from the billing system, the Company utilizes the data from the past five years to determine the allocation percentages for all core rate schedules.[23]

[22] Staff/205, CNG Response to Staff Data Request 174.
[23] Staff/205, CNG Response to Staff Data Request 174.

Forecast Results

a. Comparison of the model results are presented in Table 1. Based on Staff's forecast, the total sales for the Cascade's core customers in the test year would increase by 0.85%, compared to the 2014 actual sales, and increase by 0.21% compared to the Company's 2015 sales forecast.

b. After fitting the regression models to the given dataset, diagnostics shows that, for the estimation period 2004-2014, (B) models with weather and population included perform better than (A) models with only weather included (comparable to regression results from Cascade's base models). In Table 1, results from (B) models are indicated under Staff's forecast column (b), and results from (A) models are reported under Cascade's forecast column (c). For almost all regression models, R-Squared and Adjusted R-Squared increases, while standard error, AIC and BIC values decreases for (B) models relative to those generated from (A) models.[24] Specifically, "increases" and "decreases" in Staff's forecast column (b) indicate that values are higher or lower relative to those generated from Cascade's model. Similarly, "increases" and "decreases" in Cascade's forecast column (c) show that values are higher or lower than those generated from Staff's models.

c. As mentioned above, Staff also performed out-of-sample or cross-validation testing to measure how well model predictions fit out-of-

[24] Lower AIC and BIC values indicate better model performance.

sample data or the data that was not used to estimate the model's parameters. Error measures, presented in Table 1, indicate that Staff's forecast models generate lower RMSE and MAPE values,[25] and thus perform better than the Cascade's forecast models. Staff would like to note that RMSE and MAPE values are calculated using final sales forecast from Staff's (B) models and Cascade's final growth adjusted models. The growth adjusted sales forecast for the validation period has been provided by the Company in response to Staff Data Request No. 328.[26]

Table1. Comparison of the Forecast Results

	(a) Actual 2014	(b) Staff Forecast 2015	(c) Cascade Forecast 2015
Core Customer Sales (Dth)	73,762,366	74,390,724	74,229,686
		(B) Model	(A) Model
Estimation period		2004Jan–2014Dec	2004Jan–2014Dec
R-Squared		Increases	Decreases
Adjusted R-Squared		Increases	Decreases
Standard Error		Decreases	Decreases
AIC		Decreases	Increases
BIC		Decreases	Increases
Validation Period		2014Jan–2014Dec	2014Jan–2014Dec
RMSE		48,963	66,218
MAPE		6.87	7.91

Q. Have you prepared an exhibit to show your findings reported in Table 1 of this testimony?

[25] RMSE is the square root of the average of the square of residuals, where residual is calculated as the difference between predicted sales and actual sales. MAPE is the average difference between predicted sales and actual sales as a percentage of the latter. Lower the values of RMSE and MAPE, the better the model performance.
[26] Staff/205, CNG Response to Staff Data Request 328.

A. Yes. Exhibit 202 shows Staff's sales forecast by city gate and by tariff for the test year 2015.

Q. Does Staff have any revenue adjustments?

A. Yes. Staff incorporated the forecasted therms generated from Staff's final models into the Company's revenue requirement model to calculate the increase or decrease in revenue for all rate schedules (only schedules representing the core customers are included), for the test year 2015. The total revenue increase based on Staff's adjustments is $509,143. Staff has considered the Company's proposed 2015 customer count forecasts for this analysis, and thus, the revenue increase of $509,143 is primarily due to the higher load forecasts obtained from Staff's models.

Q. Have you prepared an exhibit to show Staff's revenue adjustments?

A. Yes, Exhibit 203 shows Staff's revenue adjustments. Staff has used the Company's Exhibit- CNG/601, for calculating the test year revenue increase. In Exhibit 203, column (G) shows staff's forecasted therms for all core rate schedules, and column (J) shows Staff's 2015 revenue adjustment by core rate schedules determined under current rates. The total revenue adjustment of $509,143 from all rate schedules is shown in column (O).

Q. Does Staff have any recommendations regarding the Company's non-core demand forecasts and customer forecasts?

A. Staff is still in the discovery phase and identifying the factors driving non-core sales demand as well as number of customers for both core and non-core customers. Staff might have relevant modifications on these issues in the next round of Staff testimony.

Q. Does Staff have any recommendations regarding the methodology used by the Company's to calculate the heating degree days (HDD) for the forecast period 2015?

A. Yes. Currently, the Company derives HDD for the forecast period based on the average daily HDD for the 30 years prior to 2015 for each weather station. So, for instance, at the weather station Baker city, the January HDD value for 2015 is the daily average HDDs for the 30 years prior January's at this station. Staff recommends that the Company consider different average values such as 25 or 20-year daily averages to represent normal HDD values. This approach will help capture the effect of warmer weather in this region at a much granular level.

Q. Does Staff have any general recommendations regarding the sales forecast methodology and models?

A. Staff believes that going forward, the Company should work with Staff and other interested parties to develop a comprehensive database comprising of economic and weather variables such as price, income, employment, different HDD cutoffs, seasonality, etc., and formulate alternative models to identify the model transparency i.e., to know the drivers of the forecasted values and plausibility of the parameter estimates relative to the economic theory on demand for natural gas.

Issue 2, Decoupling Mechanism

Q. Please provide an overview of the Company's current decoupling mechanism and its proposed changes in this general rate case filing?

A. Staff primarily focuses on the weather and conservation deferral accounts of the mechanism, public purpose funding to support conservation programs as agreed upon by stipulation, as well as the general conditions for the continuation of the mechanism that have been agreed to over time.

Two deferral accounts: In 2005, Cascade proposed a "Conservation Alliance Plan (CAP)" as a deferred accounting type decoupling mechanism, which after some modification was adopted by the Commission in 2006. [27] This mechanism allows Cascade to separately track changes in usage due to conservation and weather. Specifically, the mechanism consists of two deferral accounts, one to record changes in the margin due to weather-normalized usage (Conservation Variance) and another to track changes in the margin due to weather that varies from normal (Weather Variance).[28]

Each month the Company calculates the difference between the actual weather normalized commodity margin and expected commodity margin for the rate schedules 101 and 104. Expected margin is the baseline margin per customer multiplied by the current customer counts. The resulting dollar amount difference is recorded in the Conservation Variance deferral account.[29] Additionally, each month the Company also calculates the difference between

[27] Order No. 06-09; UG 167.
[28] Order No. 06-191; UG 167.
[29] Order No. 06-191; UG 167.

the non-weather normalized actual margin and the expected margin for its rate schedules to determine the total change in margin. The amount recorded in the Conservation Variance deferral account is then subtracted from the total change in margin and the remainder is recorded in the Weather Variance deferral account.[30]

<u>Cascade's proposal:</u> *To remove the aforementioned weather and conservation deferral accounts and have a single deferral account that will track the difference between the expected margin revenue and the non-weather normalized actual margin revenue.*[31]

Public Purpose Charge (PPC): In the 2006 stipulation in Docket No. UG 167, Cascade committed to begin contribution to the public purpose fund and to have the ETO and other Agencies to administer and deliver programs with the funding. Two types of funding streams were established regarding public purposes:

1. Effective May 1, 2006, a public purpose charge equal to 0.75 percent of current revenues, including customer service charges, in each month was assessed as a line item on the bill of rate schedules 101 and 104 customers. The level of the public purpose charge is reviewed and revised as necessary based on periodic evaluation of public purposes funding needs. Currently, the surcharge is 1.85 percent of current revenues.

2. Effective May 1, 2006, Cascade provided each month an additional 0.75 percent of current Oregon revenues generated by rate schedules 101 and 104, including customer service charges, but no less than $500,000 per year, as public purposes funds. This charge is not a separate line item on customer's bills. It is recorded as a general expense in account 908.[32]

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[30] Order No. 06-191; UG 167.
[31] CNG/300, Parvinen/16-17.
[32] Order No. 06-09; UG 167.

Under the 2006 stipulation, 80% (currently, 87%) of the funds are transferred to the ETO and 20% (currently, 13%) to the Agencies for low-income conservation programs. For the low-income efficiency programs, 75% is designated for low-income weatherization programs and the remaining 25% for bill assistance programs.[33]

<u>Cascade's proposal:</u> *To continue collecting 1.85 percent of revenues as PPC under Schedule 31 and begin collecting the additional $500,000 through the PPC tariff (Schedule 31) from residential, commercial and industrial rate schedules 101, 104, 105, and 111.*[34]

Continuation of the Mechanism: The UG 167 parties stipulated CAP would be effective until September 31, 2010, and that Cascade would obtain an independent evaluation of CAP prior to September 30, 2010 to inform the Commission's decision on whether the mechanism should continue.[35] In Docket No. UM 1283 regarding the acquisition of Cascade by MDU, continuation of the CAP was a stipulated condition. Parties to that docket stipulated the CAP should be continued until December 31, 2012, and MDU committed to continue funding the public purpose funds at the level agreed to in UG 167, provided the additional 0.75 percent is recovered from ratepayers.[36]

In September 2012, the Commission extended CAP by an additional six months to allow parties opportunity to investigate Cascade's request to continue the mechanism past the December 31, 2012 termination date.[37] In early 2013,

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[33] Docket No. UG 167.
[34] CNG/300, Parvinen/9.
[35] Docket No. UG 167.
[36] Order No. 07-221 (Docket No. UM 1283).
[37] Order No. 12-372 (Docket No. UG 167, UG 224).

the Commission approved a stipulation by Cascade, the Citizens Utility Board of Oregon (CUB), Staff, and the Northwest Industrial Gas Users (NWIGU) agreeing to (1) extend the CAP to the end of 2015, (2) discuss during 2013, parties' concerns regarding public purpose funds given to the ETO and the decoupling mechanism, and (3) file a stipulation with the Commission if any agreement is reached by December 31, 2013, regarding refinements to CAP.[38] The stipulation also included Cascade's commitment to file a general rate case by March 31, 2015, and a reservation of rights for each party to recommend changes to the CAP in the general rate case.[39]

Cascade's proposal: *To remove the expiration date due December 31, 2015 and make the CAP program permanent.*[40]

Q. Please present Staff's proposal on Cascade's decoupling mechanism.

A. Staff has reviewed the Company's proposed changes to the decoupling mechanism in this rate case filing, the Company's response to Staff's eighteen data requests, associated work papers, and also current decoupling practices by other electric and gas utilities operating in Oregon. Staff has the following recommendations:

Staff's proposal on deferral accounts:

1. *The Company should continue the existing decoupling mechanism with separate monthly weather and conservation deferral accounts to track explicitly the impact on revenue margin from weather changes and conservation practices.*

[38] Order No. 13-079; UG 234.
[39] Id.
[40] CNG/300, Parvinen/15.

Reasons: This will serve two important purposes of the CAP mechanism- weather risk mitigation and recovery of fixed costs. A consumer's bill will be adjusted during colder-than-normal months and warmer-than-normal months, while breaking the link between the Company's sales and its ability to recover cost will remove the disincentive to promote conservation. Further, the current mechanism allows the Commission and stakeholders to track the extent to which the decoupling adjustment is associated with weather. The information is useful in understanding the causes of the decoupling rate changes.

2. *The Company should update the weather normalization adjustment methodology used in the present decoupling mechanism. In particular, the Company should substitute the weather coefficient- therms usage per heating degree days (HDD) used to forecast load in this rate case for the weather normalization adjustment methodology Cascade uses for the CAP.*

Reasons: The weather normalization methodology Cascade uses for decoupling is a linear regression analysis that statistically examines the five-year relationship of actual therms per customer per month for residential and commercial general service customers and the actual heating degree days (HDDs) per month for each of Cascade's three weather areas, Bend, Baker, and Pendleton.[41] The model calculates a best fit "y" intercept that defines the "baseload" therms per customer for each weather area and class of customers. The model also calculates the best fit "x" variable for each month for each weather area on a per customer basis for each customer class. The "x" variable defines the heat sensitive

[41] Staff/205, Cascade Response to Staff Data Request 169 (c).

coefficient and reflects the usage per customer per HDD for each month. The resulting “y” intercept and “x” variable coefficients are then used to calculate total sales by month under “normal” HDDs, weather area and customer class. Cascade considers the 30-year average of HDDs as normal.[42]

In equation format, the weather normalized adjusted therms can be written as: Customers* Difference*Coefficient, where:

Difference = Normal HDD – Actual HDD, (65°F is the threshold value)

Coefficient = therms/customer/HDD

In contrast, in the load-forecasting model that Cascade uses in the current rate case, the weather variable coefficient/heat sensitivity coefficient measures usage per HDD and not usage per customer per HDD.[43] The current load forecasting model is thus, simpler and has only one equation that is used for each month by city gate, while the model under CAP mechanism has12 equations, one for each month. Further, in this rate case the heat sensitivity coefficient is evaluated based on a ten-year relationship (from 2004-2014) between actual usage and actual HDDs per month, thus providing more accurate coefficients. To have consistency between the methods used to determine total sales under normal weather and for more

[42] Specifically, the Company runs the linear regression model y = (m*x) + b for each month where y = therms/customer/day, m = therms/customer/degree day, x = degree day/day; therefore, m*x = therms/customer/day, b = therms/customer/day. After running the regression and having 12 monthly coefficients (m) and an intercept (b), the Company calculates what the number of therms/customer/day for all 12 months should have been if it were a normal month by using a normal degree/day. Then, multiplying the number of days in a month and the customers for that month to therms/customer/day, total therms are derived if it were a normal HDD month.

[43] Staff/205, Cascade Response to Staff DR 172.

accurate measures, Staff is proposing that the Company measure the CAP weather adjusted therms as:

Customers* Difference*Coefficient, where:

Difference = Normal HDD – Actual HDD, (60°F as the threshold value and 30 year average of heating degree days for normal HDD)

Coefficient = Usage/HDD

Staff also recommends using 25 or 20- year averages for "normal HDD" as well as different threshold HDD values, as proposed above for robustness checks.

Staff's proposal on public purpose funding (Schedule 31):

Staff agrees to the Company's proposal to collect the total amount provided to the ETO and other Agencies for conservation programs from rate schedules 101, 104, 105, and 111 through the PPC tariff – Schedule 31.

Reasons: Staff believes that collecting 1.85 percent of current revenues and the additional $500,000 through the PPC tariff (Schedule 31) from residential, commercial and industrial rate schedules 101, 104, 105, and 111 will spread the costs of conservation programs across all customers that benefit from these programs.

Based on the Company's response to OPUC Data Request Nos. 220, 221, and 222, Staff understands that: a) the ETO uses the public purpose fund (Schedule 31) monies collected from Schedule 101 and 104 customers to fund programs for Schedule 101 and 104 customers; and b) the ETO uses funds from the additional $500,000 to provide programs to Schedule 105 and 111 customers. During 2014, approximately $283,000 of $500,000 was used to fund Schedule 105 and 111 customer projects.

<u>Staff's proposal on the continuation of the decoupling mechanism:</u>

Staff agrees to the Company's proposal to effectively make the CAP permanent by removing the sunset date currently present in the tariffs. A review of the CAP, including both components, should be required, however, to allow Staff and interested parties to conduct a review and recommend any changes, if any.

<u>Billed and unbilled therms:</u> Staff agrees to the Company's proposal to include actual billed volumes for the monthly decoupling adjustments.[44] Under the current mechanism, each month's actual usage includes billed and unbilled therms (due to meter reading cycle).[45] The billed therms already include therms associated with last month's estimated unbilled usage (again due to meter reading cycle) but not billed until the current month. So, under the Company's current methodology, it is necessary to reverse the last month's estimated unbilled therms. The proposed method will simply use actual billed therms, where all estimated unbilled therms from one month will be included in the actual billed therms the next month. This will have no impact to the adjustments on an annual basis.

Q. Does this conclude your testimony?

A. Yes.

[44] CNG/300 Parvinen/16.
[45] Staff/205, Cascade Response to Staff DR 300 (a).

CASE: UG 287
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

July 31, 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, decoupling mechanism, revenue requirements, and tariff verification.	

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CASE: UG 287
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

July 31, 2015

Staff's 2015 Sales Forecast for Oregon by Rate Schedules (DTH)

CNGOR101	CNGOR104	CNGOR105	CNGOR111		CNGOR170	TOTAL SALES
			Commercial	Industrial		
39,683,203	27,988,505	2,526,939	541,774	1,017,954	2,632,348	74,390,724

Staff's 2015 Sales Forecast for Oregon by City Gate (Therms)

ATHENA	BAKER	UMATILLA	CHEMULT	GILCHRIST	HERMISTON	HUNTINGTON	LAPINE	MADRAS	MILTON	MISSION	NYSSA	PENDLETON	PRINVILLE	PRONGHORN	REDMOND	STANFIELD	STERNS	BEND
35,980	366,388	162,831	4,465	13,223	531,595	8,378	51,478	268,291	36,608	46,341	568,579	596,625	278,541	66,137	798,520	15,784	446,065	3,142,775

CASE: UG 287
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

July 31, 2015

		Present Billing					Current Rates				Proposed Rates				Staff's Total 2015 Revenue Adjustment
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Staff's 2015 Sales Forecast (Dth)	Rate	Margin	Staff's 2015 Revenue Adjustment	Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin	
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N) (K*L)	(O)
															$ 509,143
Rate 101	**General Residential Service**														
1	**Basic Service Charge**		699,743	$ 3.00		**$ 2,099,229**	711,020	$3.00	**$ 2,133,060**	**$ 33,830**		711,020	$ 3.00	**$ 2,133,060**	
2															
3	Delivery Charge (Jan. - Oct.)			$0.357900											
4	All therms		31,908,410 Therms		31,908,410 Therms	$ 11,420,020	39,683,203	$0.35951	**$ 14,266,508**	**$ 2,846,488**		39,683,203 Therms	0.37960	**$ 15,063,744**	
5	Delivery Charge (Nov. - Dec.)			$ 0.359510											
6			6,875,502 Therms		6,875,502 Therms	$ 2,471,812				**$ (2,471,812)**					
7	**Total Delivery Charge**		38,783,912 Therms		38,783,912 Therms	**$ 13,891,832**									
8	**Average Cost of Gas**					**21,069,994**									
9	Adjustment					(1,437)									
10	Franchise Tax					586,771									
11	PPC and Adjustments					(1)									
12	Public Purpose Fund					1,310,748									
13	Subtract out PPC Fund & Ajustments					(1,310,747)									
14	Current Month Unbilled +					21,134,752									
15	Previous Month Unbilled -					(21,673,627)									
16	CAP Adjustment					112,909									
17	Deferrals					368,007									
18	Deficiency					-									
19	**Total Non-Gas Revenue**					527,374									
20															
21	**Total Rate Schedule 101 Revenue**					**$ 37,588,429**									
Rate 104	**General Commercial Service**														
22	**Basic Service Charge**		116,330	$ 3.00		**$ 348,990**	118,063	$3.00	**$ 354,188**	**$ 5,198**		118,063	$ 3.00	**$ 354,188**	
23															
24	Delivery Charge (Jan. - Oct.)			0.258970											
25	All therms		23,046,491 Therms		23,046,491 Therms	$ 5,968,350	27,988,505	$0.25655	**$ 7,180,451**	**$ 1,212,101**		27,988,505 Therms	$ 0.298620	**$ 8,357,927**	
26	Delivery Charge (Nov. - Dec.)			$ 0.256550											
27			4,600,640 Therms		4,600,640 Therms	$ 1,180,294				**$ (1,180,294)**					
28	**Total Delivery Charge**		27,647,131 Therms		27,647,131 Therms	**$ 7,148,644**									
29	Therms Adjustment				-63,365 Therms										
30	**Average Cost of Gas**					**14,988,464.83**									
31															
32	Franchise Tax					392,987.78									
33	PPC and Adjustments					(1,666.09)									
34	Public Purpose Fund					791,751.81									
35	Adjustment					**(52,155)**									
36	Subtract out PPC Fund & Ajustments					(790,086)									
37	Current Month Unbilled +					13,445,169									
38	Previous Month Unbilled -					(13,652,915)									
39	CAP Adjustment					96,559									
40	Deferrals					284,917									
41	Deficiency					0									
42	**Total Non-Gas Revenue**					**$ 514,563**									
43															
44	**Total Rate Schedule 104 Revenue**					**$ 23,000,662**									

Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Staff's 2015 Sales Forecast (Dth)	Rate	Margin	Staff's 2015 Revenue Adjustment	Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin	Staff's Total 2015 Revenue Adjustment
	Present Billing						Current Rates				Proposed Rates				
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N) (K*L)	(O)
															$ 509,143
Rate 105	**General Industrial Service**														
45	**Basic Service Charge**		1,319	$ 12.00		$ **15,828**	1,331	$12.00	$ **15,974**	$ **146**		1,331	$ 25.00	$ **33,279**	
46															
47	**Total Delivery Charge**		2,820,467 Therms	$ 0.180320	2,820,467 Therms	$ **508,587**	**2,526,939**	$0.18032	$ **455,658**	$ **(52,929)**		2,526,939 Therms	$ 0.211060	$ **533,336**	
48															
49	**Average Cost of Gas**					**1,558,137.85**									
50															
51	Franchise Tax					46,994.09									
52	Adjustment					0.00									
53	Deferrals					93.11									
54	Deficiency					1,808.47									
55	**Total Non-Gas Revenue**					**48,895.67**									
56															
57	**Total Rate Schedule 105 Revenue**					$ **2,131,448**									
Rate 111	**Firm Commercial Service**														
	Basic Service Charge											156	$ 125.00	$ **19,500**	
58	**Total Delivery Charge**		594,477	0.14617		$ **86,895**	541,774	$0.14617	$ **79,191**	$ **(7,704)**		541,774	$ 0.16322	$ **88,428**	
59															
60	**Average Cost of Gas**					**329,000.98**									
61															
62	Franchise Tax					3,639.89									
63	Adjustment					0.00									
64	Deferrals					11.40									
65	Deficiency					0.00									
66	**Total Non-Gas Revenue**					**$3,651.29**									
67															
68	**Total Rate Schedule 111 Revenue**					$ **419,547**									

Staff's Total 2015 Revenue Adjustment

$ 509,143

		Present Billing					Current Rates				Proposed Rates				
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Staff's 2015 Sales Forecast (Dth)	Rate	Margin	Staff's 2015 Revenue Adjustment	Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin	
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N) (K*L)	(O)
	Rate 111 Firm Industrial Service														
69	**Total Delivery Charge**		1,116,978	0.14617		**$ 163,269**	1,017,954	$0.14617	**$ 148,794**	**$ (14,474)**		1,017,954	0.16322	**$ 166,150**	
70															
71	**Average Cost of Gas**					**$ 618,061**									
72															
73	Franchise Tax					$ 7,555									
74	Adjustment					$ -									
75	Deferrals					$ 28									
76	Deficiency					$ -									
77	**Total Non-Gas Revenue**					**$ 7,583**									
78															
79	**Total Rate Schedule 111 Revenue**					**$ 788,913**									
	Rate 170 Interruptible Service														
	Basic Service Charge											48	$ 160.00	**$ 7,680**	
80	**Total Delivery Charge**		2,799,401	0.12309		**$344,578**	2,632,348	$0.12309	**$324,016**	**$ (20,563)**		2,632,348	0.12302	**$323,831**	
81															
82	**Average Cost of Gas**					**$1,543,773**									
83															
84	Franchise Tax					$21,091									
85	Adjustment					0.00									
86	Deferrals					6.35									
87	Deficiency					0.00									
88	Previous Month CA1501A -					(1,909,441.81)									
89	Current Month CA1501A +					1,855,932.04									
90	**Total Non-Gas Revenue**					**(32,412.41)**									
91															
92	**Total Rate Schedule 170 Revenue**					**$1,855,938.40**									
	Rate 163 Interruptible Transportation														
93	**Dispatch Service Charge**		347	$ 500.00		**$ 173,500**	348	$500.00	**$ 174,000**	**$ 500**		348	$ 750.00	**$ 261,000**	
94															
95	Commodity Charge Jan - Nov														
96	Commodity Charge First 10,000 Therms		2,695,143 Therms	0.12393		$ 334,009	2,965,270	$0.12424	**$ 368,405**	**$ 34,396**		2,965,270 Therms	0.14596	**$ 432,811**	
97	Commodity Charge Next 10,000 Therms		2,047,727 Therms	0.11179		$ 228,915	2,250,498	$0.11210	**$ 252,281**	**$ 23,365**		2,250,498 Therms	0.13170	**$ 296,391**	
98	Commodity Charge Next 30,000 Therms		3,443,007 Therms	0.10503		$ 361,619	3,465,663	$0.10534	**$ 365,073**	**$ 3,454**		3,465,663 Therms	0.12376	**$ 428,910**	
99	Commodity Charge Next 50,000 Therms		2,580,164 Therms	0.06447		$ 166,343	2,698,995	$0.06478	**$ 174,841**	**$ 8,498**		2,698,995 Therms	0.07611	**$ 205,420**	
100	Commodity Charge Over 100,000 Therms		6,661,057 Therms	0.03266		$ 217,550	8,417,447	$0.03297	**$ 277,523**	**$ 59,973**		8,417,447 Therms	0.03873	**$ 326,008**	
101							104,524	$0.03297	**$ 3,446**	**$ 3,446**		104,524 Therms	0.02194	**$ 2,293**	
102	Commodity Charge Dec														
103	Commodity Charge First 10,000 Therms		262,139 Therms	0.12424		$ 32,568				**$ (32,568)**					
104	Commodity Charge Next 10,000 Therms		211,944 Therms	0.11210		$ 23,759				**$ (23,759)**					
105	Commodity Charge Next 30,000 Therms		386,316 Therms	0.10534		$ 40,695				**$ (40,695)**					
106	Commodity Charge Next 50,000 Therms		217,091 Therms	0.06478		$ 14,063				**$ (14,063)**					
107	Commodity Charge Over 100,000 Therms		531,504 Therms	0.03297		$ 17,524				**$ (17,524)**					
108	**Total Commodity Charge**		19,036,092 Therms			**$ 1,437,045**									
109															
110	Franchise Tax					$ 22,742									
111	Gross Revenue Fee					$ 34,377									
112	Adjustment					$ -									
113	Previous Month CA1501A -					$ (1,667,664)									
114	Current Month CA1501A +					$ 1,670,084									
115	Deferrals					$ 1,029									
116	**Total Non-Gas Revenue**					**$ 60,568**									
117															
118	**Total Rate Schedule 163 Revenue**					**$ 1,671,113**									

Staff's Total 2015 Revenue Adjustment
$ 509,143

	Present Billing						Current Rates				Proposed Rates				
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Staff's 2015 Sales Forecast (Dth)	Rate	Margin	Staff's 2015 Revenue Adjustment	Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin	
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N) (K*L)	(O)
Rate 164	**Interruptible Transportation**														
119	Dispatch Service Charge		31	$ 500.00		$ 15,500	36	$500.00	$ 18,000	$ 2,500		36	$ 750.00	$ 27,000	
120															
121	Commodity Charge Jan - Nov														
122	Commodity Charge First 10,000 Therms		220,000 Therms	0.12393		$27,265	360,000	$0.12424	$44,726	$ 17,462		360,000 Therms	0.14596	$52,546	
123	Commodity Charge Next 10,000 Therms		220,000 Therms	0.11179		$24,594	360,000	$0.11210	$40,356	$ 15,762		360,000 Therms	0.13170	$47,412	
124	Commodity Charge Next 30,000 Therms		660,000 Therms	0.10503		$69,320	1,080,000	$0.10534	$113,767	$ 44,447		1,080,000 Therms	0.12376	$133,661	
125	Commodity Charge Next 50,000 Therms		1,100,000 Therms	0.06447		$70,917	1,800,000	$0.06478	$116,604	$ 45,687		1,800,000 Therms	0.07611	$136,998	
126	Commodity Charge Next 400,000 Therms		8,642,740 Therms	0.03266		$282,272	9,629,514	$0.03297	$317,485	$ 35,213		9,629,514 Therms	0.03873	$372,951	
127	Commodity Charge Over 500,000 Therms		2,505,614 Therms	0.01746		$43,748	1,651,887	$0.01777	$29,354	$ (14,394)		1,651,887 Therms	0.02194	$36,242	
128															
129	Commodity Charge Dec														
130	Commodity Charge First 10,000 Therms		20,000 Therms	0.12424		$ 2,485				$ (2,485)					
131	Commodity Charge Next 10,000 Therms		20,000 Therms	0.11210		$ 2,242				$ (2,242)					
132	Commodity Charge Next 30,000 Therms		60,000 Therms	0.10534		$ 6,320				$ (6,320)					
133	Commodity Charge Next 50,000 Therms		100,000 Therms	0.06478		$ 6,478				$ (6,478)					
134	Commodity Charge Next 400,000 Therms		723,500 Therms	0.03297		$ 23,854				$ (23,854)					
135	Commodity Charge Over 500,000 Therms		110,264 Therms	0.01777		$ 1,959				$ (1,959)					
138	**Total Commodity Charge**		14,382,118 Therms			$561,453									
139															
140	Gross Revenue Fee					$ 12,315									
141	Previous Month CA1501A -					(589,268.54)									
142	Current Month CA1501A +					$ 592,608									
143	**Total Non-Gas Revenue**					$ 15,654									
144															
145	**Total Rate Schedule 164 Revenue**					$ 592,608									
Rate 902	**Interruptible Transportation**														
146	**Dispatch Service Charge**		12	500		$6,000	12	$500.00	$6,000	$ -		12	500	$6,000	
147															
148	Commodity Charge Jan-Oct		151,419,156 Therms	$0.0014931		$226,083.94	199,635,071	$0.0015244	$304,323.70	$ 78,240		199,635,071 Therms	$0.0015244	$304,324	
149	Commodity Charge Nov-Dec		33,116,889 Therms	$0.0015244		$50,483.39				$ (50,483)					
150	**Total Commodity Charge**		184,536,045 Therms			$276,567.33									
151															
152	Contract Demand Charge		10800000		$0.1005555	$1,085,999.40	10,800,000	$0.10056	$1,085,999.40			10800000	$0.1005555	$1,085,999	
153															
154	Gross Revenue Fee					$29,212									
155	Previous Month CA1501A -					(1,397,778.76)									
156	Current Month CA1501A +					1,388,199.64									
157	**Total Non-Gas Revenue**					19,632.93									
158															
159	**Total Rate Schedule 902 Revenue**					$1,388,199.66									
Rate 903	**Interruptible Transportation**														
160	**Dispatch Service Charge**		12	500		$6,000	12	$500.00	$6,000	$ -		12	500	$6,000	
161															
162	Commodity Charge Jan-Oct		7,569,950 Therms	0.0114416		$86,612	9,130,035	$0.01168	$106,656	$ 20,044		9,130,035 Therms	0.0116819	$106,656	
163	Commodity Charge Nov-Dec		1,487,374 Therms	0.0116819		$17,375				$ (17,375)					
164	**Total Commodity Charge**		9,057,324 Therms			$103,988									
165															
166	Contract Demand Charge		192000	0.09375		$18,000	192,000	$0.09375	$18,000			192000	0.09375	$18,000	
167															
168	Gross Revenue Fee					$2,732									
169	Previous Month CA1501A -					-$130,720									
170	Current Month CA1501A +					$130,198									
171	**Total Non-Gas Revenue**					$2,210									
172															
173	**Total Rate Schedule 903 Revenue**					$130,198									
Rate 904	**Interruptible Transportation**														
174	**Dispatch Service Charge**		12	500		$6,000	12	$500.00	$6,000	$ -		12	500	$6,000	
175															
176	Commodity Charge Jan-Oct		6,975,192 Therms	0.0076744		$53,530	10,261,867	$0.00784	$80,408	$ 26,877		10,261,867 Therms	0.0078356	$80,408	
177	Commodity Charge Nov-Dec		1,728,057 Therms	0.0078356		$13,540				$ (13,540)					
178	**Total Commodity Charge**		8,703,249 Therms			$67,071									
179															
180	Contract Demand Charge		499200	0.0877404		$43,800	499,200	$0.08774	$43,800			499200	0.0877404	$43,800	
181															
182	Gross Revenue Fee					$2,495									
183	Francise Tax					$2,387									
184	Previous Month CA1501A -					-$121,753									
185	Current Month CA1501A +					$122,827									
186	**Total Non-Gas Revenue**					$5,956									
187															
188	**Total Rate Schedule 904 Revenue**					$122,827									
Rate 905	**Interruptible Transportation**														
189	**Dispatch Service Charge**		12	500		$6,000	12	$500.00	$6,000	$ -		12	500	$6,000	
190															
191	Commodity Charge Jan-Oct		7,338,029 Therms	0.0107411		$78,819	9,414,232	$0.01097	$103,242	$ 24,424		9,414,232 Therms	0.0109666	$103,242	

		Present Billing					Current Rates					Proposed Rates			Staff's Total 2015 Revenue Adjustment
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Staff's 2015 Sales Forecast (Dth)	Rate	Margin	Staff's 2015 Revenue Adjustment	Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin	
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N) (K*L)	(O)
															$ 509,143
192	Commodity Charge Nov-Dec		1,586,093 Therms	0.0109666		$17,394				$ (17,394)					
193	**Total Commodity Charge**		8,924,122 Therms			**$96,213**									
194															
195	Contract Demand Charge		480000	0.04375		**$21,000**	480,000	$0.04375	**$21,000**			480000	0.04375	**$21,000**	
196															
197	Gross Revenue Fee					$2,630									
198	Previous Month CA1501A -					-$125,843									
199	Current Month CA1501A +					$124,589									
200	**Total Non-Gas Revenue**					**$1,376**									
201															
202	**Total Rate Schedule 905 Revenue**					**$124,589**									

CASE: UG 287
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Opening Testimony

July 31, 2015

Request No. 169

Date prepared: 5/28/2015

Preparer: Michael Parvinen

Contact: Pamela Archer

Telephone: (509)-734-4591

169. Please refer to Exhibit CNG/307 that presents monthly weather and conservation deferrals from July, 2013 through June, 2014.

a. Provide the electronic version of Exhibit 307 (with cell formulae intact);
b. Provide all electronic spreadsheets (with cell formulae intact) used to derive the weather and conservation deferral balances shown in Rows 110 and 111 of Exhibit 307;
c. Weather normalization is calculated as customers* difference*coefficient. Provide electronic spreadsheets showing customer counts and the calculation of actual Degree Days, normal Degree Days, and coefficients for therms per Degree Days, by month for the period July, 2013 through June, 2014;
d. Provide electronic spreadsheets (with cell formulae intact) used to calculate baseline commodity margin/customer for residential schedule (Row 39) and commercial schedules (Row 91); and
e. Provide responses to parts b, c, and d for the time period July 2014 through December 2014.

Response:

a. Please see spreadsheet A169a.xls.
b. Please see spreadsheet A169a.xls.
c. Please see spreadsheet A169c Weather Normalization.xlsm.
d. Please see spreadsheet A169d Jul-Oct Baseline Adjustment.xlsx & A169d Nov-Jun Baseline Adjustment.xlsx.
e. Please see spreadsheet A169e 12-14 OR Cap.xls, A169e Jul-Oct CAP Baseline Adjustment.xlsx, A169e Nov-Dec CAP Baseline Adjustment.xlsx, and A169e Weather Normalization.xlsm.

Request No. 172

Date prepared: 5/19/2015

Preparer: Brian Robertson

Contact: Pamela Archer

Telephone: (509)-734-4591

172. CNG/300, Parvinen 16, reports that 60 Heating Degree Day (HDD) is a better fit than the historical 65 HDD. Please explain the methodology used in the present rate case, UG 287, to calculate use per HDD. Please explain if the current method is different from that used in prior years for weather normalization equation.

Response:

Please refer to CNG/401 Page 18 of 24 where the methodology to calculate use per HDD is discussed.

The current model is different from that used in prior years for weather normalization equation. The current model uses therms/HDD as the coefficient to forecast while the old model used therms/customer/HDD. The current model has one equation that is used for each month by CityGate while the old model has 12 equations, one for each month.

Request No. 174

Date prepared: 5/19/2015

Preparer: Brian Robertson

Contact: Pamela Archer

Telephone: (509)-734-4591

174. Please refer to Archer Workpapers PJA Exhibit 601.xlsx. Row 4 of Tab "Volume Forecast 2015" shows Annual Oregon Volume Forecasts (in therms) by rate schedules for the test year 2015. Please provide the following:

   a. The monthly volume forecasts (in therms) by rate schedules for the time period January 2015 to December 2015. Provide the data in electronic spreadsheet format with all cell references and formulae intact;

   b. The final dataset and programming files used in UG 287 to generate the monthly volume forecasts for each rate schedule for the test period January 2015 to December 2015. Provide the data in electronic spreadsheet format with all cell references and formulae intact;

   c. The definition of response and independent variables used to generate monthly volume forecasts for each rate schedule;

   d. Please provide the information requested in sections (a-c) for the years 2011, 2012, 2013, and 2014;

   e. The monthly volume forecasts (in therms) by rate schedules for the time period January 2015 to December 2015, before the EIA energy efficiency adjustments are applied, but after all other adjustments are done. Provide the data in electronic spreadsheet format with all cell references and formulae intact; and

   f. Provide the monthly volume forecasts (in therms) by rate schedules generated in Washington for the test year 2015. Provide the data in electronic spreadsheet format with all cell references and formulae intact.

Response:

174(a) Please refer to the "DemandForecast_Tariff" tab in Excel spreadsheet Confidential 174.xlsx[1].

174(b) See 174(a) above.

174(c) The response, or dependent, variable used to generate the monthly volume forecast for each rate schedule is therms/HDD. The independent variable is the HDD for the CityGates respective weather location by month.

174(d) Cascade pulls historical CityGate data from each pipeline Energy Bulletin Board (EBB) systems. EBB systems are where pipeline companies post volumes for the benefit of operators (in this case, Cascade) and pipeline transport shippers scheduling natural gas for delivery to those specific CityGates. The EBB systems offer historical volume data by CityGate but do not break the data down by rate schedule. Historical monthly data for the years 2011, 2012, 2013 and 2014 are provided in the "Demand" tab in Excel spreadsheet Confidential 174.xlsx[1].

174(e) Cascade decided that any Energy Efficiency gains will be determined by the conservation department using their models. The monthly volume forecasts provided do not have an EIA energy efficiency adjustment.

174(f) Please refer to the "DemandForecast_Tariff" tab in Excel spreadsheet Confidential 174.xlsx[1].

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1 Excel spreadsheet 174.xlsx contains proprietary information and should be given confidential treatment.

Request No. 300

Date prepared: June 29, 2015

Preparer: Mike Parvinen

Contact: Pamela Archer

Telephone: (509)-734-4591

300. Please refer to CNG/300, Parvinen/16. Lines 10-16 state that Cascade's proposal to eliminate the use of unbilled volumes will have no impact on the monthly decoupling adjustments.

a. Please provide a detail explanation of the method used to include and exclude unbilled volumes from one month to another under the current and proposed decoupling mechanism.

b. The company provided an excel file "A169e 12-14 OR CAP.xls" showing the current decoupling adjustments in response to OPUC staff data request 169 (e). In this file, Rows 42 and 94 of tab "JUNE302014" shows the actual therms from July, 2013 through June, 2014 for schedules 101 and 104.

   i. Please explain how you include billed and unbilled therms to calculate the actual therms for each month.
   ii. Is the actual therms for each month calculated as (billed therms + current month unbilled therms – previous month unbilled therms)?
   iii. Please provide the excel spreadsheet (with cell formulae intact) showing the calculation of actual therms for schedules 101 and 104, from July 2011 through Dec 2015.

c. The company provided an excel file "A168 Proposed 12-14 OR CAP.xls" showing the proposed decoupling adjustments in response to OPUC staff data request 168. In this file, Row 19 of tab "JUNE302014" shows the actual therms from July, 2013 through June, 2014 for Schedule 101.

   i. Please explain why you have included only billed therms to calculate the actual therms for each month.
   ii. How do you account for unbilled therms in calculating actuals for each month under proposed mechanism?

iii. Please provide the excel spreadsheet (with cell formulae intact) showing the calculation of actual therms for schedules 101 and 104, from July 2013 through Dec 2015.

Response:

a. Under the current mechanism, unbilled therms are included in the calculation of actual revenue from customers each month. This method is consistent with how revenues are actually booked each month. Each month's actual usage includes some amount of therms that are billed and some therms that have been estimated to be consumed but not yet billed (due to meter reading cycle). The billed therms also include therms associated with last month's extimated unbilled usage (again due to meter reading cycle) but not billed until the current month.

   The next month's billed amount from the meter read will include the unbilled therms from the previous month so a reversal of the last month's estimated unbilled therms used is important to not double counts the volumes. Them, the estimated unbilled but consumed therms is estimated again for the month but will be reversed again the next month.

   The proposed method simply uses actual billed volumes. On an annual basis a total of 12 months actual usage is included. The only difference from the previous method is the timing of the first and last month's unbilled volumes which are estimated numbers. The proposal is an acceptance from the independent evaluator's recommendation of improvements to the decoupling mechanism.

b. i. See a. above.
   ii. Yes. This number represents estimated actual consumed therms in any given month.
   iii. Refer to the tab labeled "Unbilled Ths" in the excel file referenced in this request for the calculation. Specifically rows 71 and 64, respectively.

c. i. The independent evaluator of Cascade's mechanism recommended to removing all unbilled volumes and only use billed volumes in the calculation. Cascade is proposing to accept and utilize that recommendation. The spreadsheet referred to in this request performs the calculation based on the recommendation from the independent evaluator.
   ii. Unbilled therms are not specifically included. All estimated unbilled therms from one month are included in the actual billed therms the next month.
   iii. Refer to b.iii. above.

Request No. 328

Date prepared: July 17, 2014

Preparer: Brian Robertson

Contact: Pamela Archer

Telephone: (509)-734-4591

328. Please consider 2004-2013 as the estimation period and provide the excel spreadsheet (with cell formulae intact) showing the 2014 sales forecast for the core customers by city-gate.

Response:

See excel spreadsheet A328.xlsx for the 2014 sales forecast for the core customers by city-gate considering 2004-2013 as the estimation period and 2014 actual HDDs.

CASE: UG 287
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

July 31, 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/301.

Q. Did you include any other exhibits for this testimony?

A. Yes. Exhibit Staff/302 contains Cascade's response to Staff Data Request No. 310.

Q. What is the purpose of your testimony?

A. I discuss two topics related to Cascade Natural Gas' (CNG's or Company's) miscellaneous operating revenue. The first is Staff's continuing investigation into CNG's inclusion of revenue due to Purchased Gas Adjustment (PGA) Commodity Sharing and the second is whether an adjustment is warranted to any other component of miscellaneous operating revenue.

ISSUE, MISCELLANEOUS OPERATING REVENUE

Q. Please summarize what Cascade includes in revenue requirement for miscellaneous operating revenue.

A. The Company's test year adjusted total for miscellaneous operating revenue is $663,281. This value is the sum of an initial calculation of $277,779.00 and an adjustment due to Purchased Gas Adjustment (PGA) Commodity Sharing of $385,502.00.

Q. Why is Staff concerned that the Company included the PGA Commodity Sharing adjustment in its test year miscellaneous operating revenue?

A. Staff is concerned that there could be double-counting if this type of revenue is included to reduce base rates and also included in annual PGA sharing computations. Staff has an outstanding follow-up data request asking for explanation about the inclusion of the PGA Commodity Sharing adjustment within miscellaneous operating revenue. Further, Staff has discussed this issue with the Company. From this discussion, it appears that the Company will likely remove $385,502.00 from its initial derivation of miscellaneous revenue. This is the focal point of Staff's follow-up data request. If this is a one-time event with the level of PGA Commodity Savings potentially being positive or negative in benefit to customers, Staff will recommend the appropriate vehicle for handling this issue is through the PGA.

Q. Please summarize Staff's analysis of the remaining components of miscellaneous operating revenue.

A. Staff initiated two data requests to identify the major components in miscellaneous operating revenue and to review the entire balance by component. The Company's initial calculation for 2014 miscellaneous operating revenue is the sum of: miscellaneous service revenue, service line modification, rent from gas property, interdepartmental rents, third party damage, and other gas revenue.[1] Miscellaneous service revenue, at $193,624.08, represents the majority of this sum.[2] Miscellaneous service revenue is revenue from the miscellaneous charges listed in Rate Schedule No. 200 in the Company's tariff. Examples include reconnection charges, late payment charges, and returned check charges.[3]

Q. Have you included an exhibit that displays the Company's yearly miscellaneous operating revenue by component?

A. Yes, Cascade's response to Staff Data Request No. 310 shows this information. I include this response as Exhibit Staff/302.

Q. Please summarize Staff's position regarding miscellaneous service revenue.

A. In some years, the Company accounted for multiple miscellaneous service revenue components. To simplify, Staff summed the miscellaneous service

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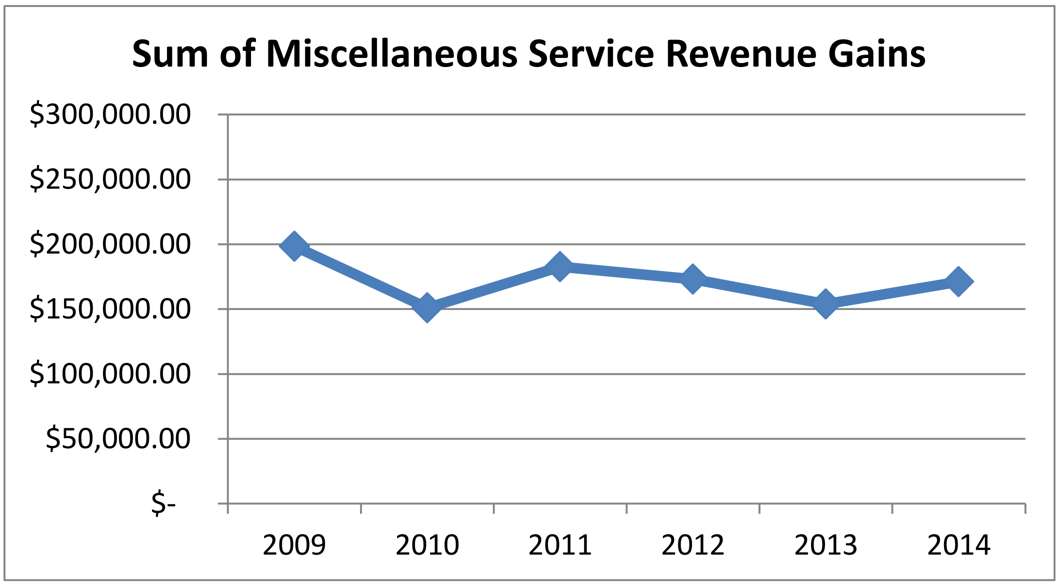
[1] Staff/302, St Brown/1-4, Cascade Response to Staff Data Request No. 310.
[2] Staff/302, St Brown/1-4, Cascade Response to Staff Data Request No. 310.
[3] Staff/302, St. Brown/5, Cascade Natural Gas Corporation, Rates, Rules and Regulations for Natural Gas Service in Oregon.

revenue gains in each year and the miscellaneous service revenue losses in each year. Figure 1 below, demonstrates that the sum of miscellaneous service revenue gains has remained relatively stable since 2009. Staff's analysis does not include years prior to 2009 because the Company reports that the years 2006-2008 are not accessible due to software upgrades in February 2009.[4]

Figure 1



Because miscellaneous charges contribute to miscellaneous service revenue gains, yearly miscellaneous service revenue is expected to be impacted by the yearly number of customers.

Q. What is Staff's conclusion regarding 2014 miscellaneous service revenue?

A. Staff has reviewed the Company's 2014 miscellaneous service revenue and is in agreement with the Company's computation.

[4] Staff/302, Cascade Response to Staff Data Request 310.

Q. Please summarize Staff's position regarding miscellaneous operating revenue.

A. As noted above, the Company included PGA Commodity Sharing revenues in its miscellaneous operating revenue estimate. Staff is continuing to investigate whether inclusion of these revenues in base rates is appropriate. Staff has no other adjustment to miscellaneous operating revenues.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 287
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

July 31, 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. 9730
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 287
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

July 31, 2015

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 310

Date prepared: July 2, 2015

Preparer: Candice Tschauner

Contact: Pamela Archer

Telephone: (509)734-4591

310. For calendar years 2006 through 2014, inclusive, please provide the value of other revenues, and for each year identify the major components included in other revenues.

Response: Please see A310.xlsx for details. Please note that years 2006-2008 are not accessible due to software upgrades in February 2009. Data is provided for years 2009-2014.

A310.xlsx, "Summary" tab

CNG Other Operating Revenue Summary 2009-2014

2014			
Object Code	**Subsidiary account**	**Explanation**	**Amount**
4880	MSRV	Miscellaneous Service Revenue	171,148.79
4880	SLMD	Service Line Modification	22,475.29
4930	None	Rent from Gas Property	11,000.00
4940	None	Interdepartmental Rents	24,264.04
4950	DAMG	Third Party Damage	48,791.15
4950	MMAT	Miscellaneous Material Sales	100.00
			277,779.27

2013			
Object Code	**Subsidiary account**	**Explanation**	**Amount**
4880	MSRV	Miscellaneous Service Revenue	153,961.10
4880	SLMD	Service Line Modification	12,136.54
4880	SPLS	Service Plus	3,475.00
4930	None	Rent from Gas Property	11,049.10
4940	None	Interdepartmental Rents	22,681.99
4950	DAMG	Third Party Damage	24,132.24
4950	MISC	Miscellaneous Other	2,462.16
4950	MMAT	Miscellaneous Material Sales	39.04
5192	2488	Miscellaneous Service Revenue	1.72
5192	2488	Miscellaneous Service Revenue	12.52
5400	2488	Miscellaneous Service Revenue	(124.71)
			229,826.70

2012			
Object Code	**Subsidiary account**	**Explanation**	**Amount**
4880	MSRV	Miscellaneous Service Revenue	173,054.95
4880	SLMD	Service Line Modification	23,824.28
4880	SPLS	Service Plus	5,467.75
4930	None	Rent from Gas Property	11,000.00
4940	None	Interdepartmental Rents	-
4950	DAMG	Third Party Damage	12,650.39
4950	MISC	Miscellaneous Other	4,612.99
4950	MMAT	Miscellaneous Material Sales	138.56
5110	2488	Miscellaneous Service Revenue	(346.18)
5191	2488	Miscellaneous Service Revenue	(28.60)
5192	2488	Miscellaneous Service Revenue	(0.31)
5194	2488	Miscellaneous Service Revenue	(32.65)
5195	2488	Miscellaneous Service Revenue	(94.58)
5197	2488	Miscellaneous Service Revenue	(6.40)
5199	2488	Miscellaneous Service Revenue	(2.51)
5300	2488	Miscellaneous Service Revenue	(970.78)
5410	2488	Miscellaneous Service Revenue	(37.61)
5421	2488	Miscellaneous Service Revenue	(2.70)
			229,226.60

2011			
Object Code	**Subsidiary account**	**Explanation**	**Amount**
4880	MSRV	Miscellaneous Service Revenue	182,639.97
4880	SLMD	Service Line Modification	23,629.06
4880	SPLS	Service Plus	127,063.05
4880	MMAT	Miscellaneous Material Sales	(135.11)
4930	None	Rent from Gas Property	13,000.00
4940	None	Interdepartmental Rents	-
4950	DAMG	Third Party Damage	5,276.39
4950	SLMD	Service Line Modification	450.55
4950	MMAT	Miscellaneous Material Sales	491.51
5110	2488	Miscellaneous Service Revenue	(17,110.60)
5120	2488	Miscellaneous Service Revenue	(7,229.57)
5131	2488	Miscellaneous Service Revenue	(271.95)
5191	2488	Miscellaneous Service Revenue	(2,177.97)
5192	2488	Miscellaneous Service Revenue	(29.79)
5194	2488	Miscellaneous Service Revenue	(2,104.61)
5195	2488	Miscellaneous Service Revenue	(2,508.87)
5196	2488	Miscellaneous Service Revenue	1,570.61
5197	2488	Miscellaneous Service Revenue	(790.34)
5199	2488	Miscellaneous Service Revenue	(189.91)
5211	2489	Miscellaneous Service Revenue	(2,161.34)
5300	2490	Miscellaneous Service Revenue	(19,945.38)
5410	2491	Miscellaneous Service Revenue	(3,648.46)
5421	2492	Miscellaneous Service Revenue	(357.94)
5521	2493	Miscellaneous Service Revenue	(187.73)
5522	2494	Miscellaneous Service Revenue	(45.73)
5652	2495	Miscellaneous Service Revenue	(3.22)
			295,222.62

2010			
Object Code	**Subsidiary account**	**Explanation**	**Amount**
4880	MSRV	Miscellaneous Service Revenue	146,840.55
4880	SLMD	Service Line Modification	14,043.37
4880	SPLS	Service Plus	75,470.21
4880	MMAT	Miscellaneous Material Sales	396.69
4880	TUNE	Tune Up Inspections	250.00
4930	None	Rent from Gas Property	13,435.00
4940	None	Interdepartmental Rents	-
4950	DAMG	Third Party Damage	27,723.42
4950	SLMD	Service Line Modification	5,632.99
4950	MMAT	Miscellaneous Material Sales	765.61
4950	MISC	Miscellaneous Other	183.72
5110	2488	Miscellaneous Service Revenue	(55,857.68)
5120	2488	Miscellaneous Service Revenue	(7,339.97)
5150	2488	Miscellaneous Service Revenue	(9.74)
5191	2488	Miscellaneous Service Revenue	(5,218.37)
5192	2488	Miscellaneous Service Revenue	(349.13)
5194	2488	Miscellaneous Service Revenue	(5,708.73)
5195	2488	Miscellaneous Service Revenue	(6,179.24)
5196	2488	Miscellaneous Service Revenue	4,069.50
5197	2488	Miscellaneous Service Revenue	(3,294.24)

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5199	2488	Miscellaneous Service Revenue	(639.55)
5211	2488	Miscellaneous Service Revenue	(43,555.46)
5300	2488	Miscellaneous Service Revenue	(22,423.33)
5410	2488	Miscellaneous Service Revenue	(8,310.07)
5421	2488	Miscellaneous Service Revenue	(96.45)
5511	2488	Miscellaneous Service Revenue	(49.04)
5514	2488	Miscellaneous Service Revenue	(26.18)
5521	2488	Miscellaneous Service Revenue	(1,371.39)
5522	2488	Miscellaneous Service Revenue	(2,018.85)
5630	2488	Miscellaneous Service Revenue	(1,036.00)
5640	2488	Miscellaneous Service Revenue	(516.97)
5932	2488	Miscellaneous Service Revenue	(243.50)
			124,567.17

2009

Object Code	Subsidiary account	Explanation	Amount
4880	MSRV	Miscellaneous Service Revenue	198,300.20
4880	SLMD	Service Line Modification	5,443.46
4880	SPLS	Service Plus	84,544.98
4880	MMAT	Miscellaneous Material Sales	-
4880	TUNE	Tune Up Inspections	3,995.00
4930	None	Rent from Gas Property	14,058.00
4940	None	Interdepartmental Rents	-
4950	DAMG	Third Party Damage	14,404.40
4950	SLMD	Service Line Modification	34,272.50
4950	MMAT	Miscellaneous Material Sales	1,469.73
4950	MISC	Miscellaneous Other	244.27
5110	2488	Miscellaneous Service Revenue	(53,823.96)
5120	2488	Miscellaneous Service Revenue	(4,166.02)
5191	2488	Miscellaneous Service Revenue	(4,660.25)
5192	2488	Miscellaneous Service Revenue	(2,755.26)
5194	2488	Miscellaneous Service Revenue	(6,342.79)
5195	2488	Miscellaneous Service Revenue	(1,450.96)
5197	2488	Miscellaneous Service Revenue	(3,113.40)
5199	2488	Miscellaneous Service Revenue	(544.92)
5211	2488	Miscellaneous Service Revenue	(10,135.37)
5300	2488	Miscellaneous Service Revenue	(12,650.44)
5410	2488	Miscellaneous Service Revenue	(6,489.96)
5421	2488	Miscellaneous Service Revenue	(115.85)
5511	2488	Miscellaneous Service Revenue	(80.65)
5521	2488	Miscellaneous Service Revenue	(412.39)
5522	2488	Miscellaneous Service Revenue	(989.13)
5610	2488	Miscellaneous Service Revenue	(12.52)
5630	2488	Miscellaneous Service Revenue	(321.90)
5640	2488	Miscellaneous Service Revenue	(544.66)
5651	2488	Miscellaneous Service Revenue	(2.91)
5851	2488	Miscellaneous Service Revenue	(64.09)
5912	2488	Miscellaneous Service Revenue	(947.43)
5932	2488	Miscellaneous Service Revenue	-246.5
			246,861.18

VARIOUS MISCELLANEOUS CHARGES
RATE SCHEDULE NO. 200

APPLICABILITY:
This schedule sets forth the provisions for various charges throughout these rules and regulations. The name and amount of the charges are listed below. The rules or rate schedules to which each charge applies are in parenthesis.

I. Reconnection Charge (Rule 3 - Part G, Rule 3 - Part H, Subsection 3):

A standard reconnection charge of 32 dollars ($32.00) will be required to reestablish service between the business hours of 8 a.m. and 5 p.m. on Monday through Friday, excluding holidays. Customers may schedule an After Hours reconnection for reestablishment of service between 5 p.m. and 9 p.m., Monday through Friday for a charge of 50 dollars ($50). Customers requesting after hours reconnection for the same business day, or on a Saturday, Sunday or holidays will be charged a fee of 100 dollars ($100.00) to reestablish service.

A reconnection charge will be required for reestablishment of service at the same address for the same person taking service under a rate schedule specifying a yearly contract, if service has been disconnected at the customer's request, in the amount of 32 dollars ($32.00).

II. Deposit for Meter Test - (Rule 6 - Paragraph 4):

$50.00

III. Disconnect Visit Charge - (Rule 3 - Part L), Rule 3 - Part M, Subsection 7:

A disconnect charge of ten dollars ($10.00) may be charged, whenever Cascade is required to visit a customer's address for the purpose of disconnecting service or reconnecting service and due to the customers action is unable to complete the disconnection or reconnection.

IV. Late Payment Charge – (Rule 3 - Part N):

A late payment charge at a rate determined by the Commission based upon a survey of prevailing market rates will be charged to the customer's current bill when the customer has a prior balance owing of $200 or more.

V. Returned Check Charge - (Rule 4 - Part D):

A returned check fee of ten dollars ($10.00) may apply for any check returned from the bank unpaid.

VI. Residential Excess Flow Valves – (Rule 7):

In Conjunction With The Construction Of A New Service Line:		$ 38.00
Modifying an Existing Service Line:		
Time of Construction Crew	up to	$220.00 per hour
Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.		
Installation of the Excess Flow Valve		$ 38.00

(Continued on Next Page)

CASE: UG 287
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

July 31, 2015

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

A. My name is Erik Colville. My business address is 201 High St SE, Suite 100, Salem, OR 97301.

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 present Staff's recommendations regarding the rate treatment of gas storage in rate base and "other gas supply expense," and an issue related to the Integrated Resource Plan (IRP) process.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/401, consisting of one page, and Exhibit Staff/402, consisting of one page.

ISSUE: 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.[1] "Working gas inventory" is the gas that flows in and out of the storage reservoir (or LNG tank) to serve customer loads.[2] Cascade does not own its own storage facilities and owns no "cushion gas." [3] Accordingly, the

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[1] See e.g., Order No. 13-349 (UM 1651).
[2] Id.
[3] According to Cascade's response to Staff Data Request 199.

only costs for storage gas at issue in this rate case are those for working gas inventory.

Q. Please summarize Cascade's and your proposed rate treatment of Cascade's gas storage costs.

A. Cascade includes $552,675 for gas storage in its rate base. This amount is the 2014 end-of-year balance for Cascade's working gas inventory.[4] I do not oppose including the cost of working gas inventory in rate base. However, I propose to adjust the amount Cascade includes in rate base downward by $16,804, so that the amount included in rate base is 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 expressly address the appropriate regulatory treatment of working gas inventory costs, but all three gas utilities in Oregon currently include these costs in rate base.[5] In 1977, the Commission expressly allowed Cascade to include its gas storage costs as an asset in rate base.[6]

Q. Did Staff oppose inclusion of working gas inventory in rate base in NW Natural's last general rate case (UG No. 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

[4] CNG/301, Parvinen/Page 1 of 1, line 26, Column (1).
[5] See e.g., Order No. (although not expressly addressed, Avista's rate base includes working gas inventory); and Order No. 13-349 (Commission adopting stipulation Including NW Natural Gas Company's working gas inventory in rate base).
[6] Re Cascade Natural Gas Corporation, Order No. 77-125 (1977 WL 440903 at 3).

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.[7]

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 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 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.

[7] Order No. 13-049.

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.

To supplement the contents of Cascade's rate case filing, I issued data request (DR) 122 and follow up DRs 199, 200 and 201. DR 122 requested, by month, data supporting the dollar amount of gas in storage that was or is included in rate base for the year 2004-2014. Cascade's DR 122 revised response provided the 2014 monthly amounts of storage gas. That data and the calendar year average of that data is calculated and presented in the table below.

	2014
Jan	$677,955
Feb	$394,933
Mar	$285,751
Apr	$436,258
May	$500,136
Jun	$500,136
Jul	$551,439
Aug	$639,098
Sep	$639,098
Oct	$643,821
Nov	$609,150
Dec	$552,675
Cal Yr Avg	$535,871

Based upon the DR 122 revised response data, the gas storage in rate base, using the average for calendar year 2014, is $535,871.

Q. Please describe your proposed adjustment to Gas Storage in Rate Base.

A. I propose to reduce Cascade's gas storage in rate base by $16,804, from $552,675 to $535,871.

Issue: Other Gas Supply Expense (FERC Account 813)

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.[8]

Q. Please summarize Cascade's proposal related to other gas supply expense.

A. Cascade proposes to use its total other gas supply expense for calendar year 2014 for the test year expense. This proposed amount is $10,273, based upon Cascade's response to my DRs 195 and 196. Cascade does not adjust the 2014 base year amount.

Q. Please summarize Commission historical treatment of other gas supply 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.

[8] See 18 C.F.R. FERC Account 813.

Q. What is your recommendation?

A. I conclude that using the actual 2014 expense is not the optimum way to calculate the appropriate amount to include in revenue requirement. Accordingly, my recommendation is based on review of Cascade's actual other gas expense for the previous three years.

Q. Please summarize your analysis.

A. Exhibit Staff/402 contains the information as described below.

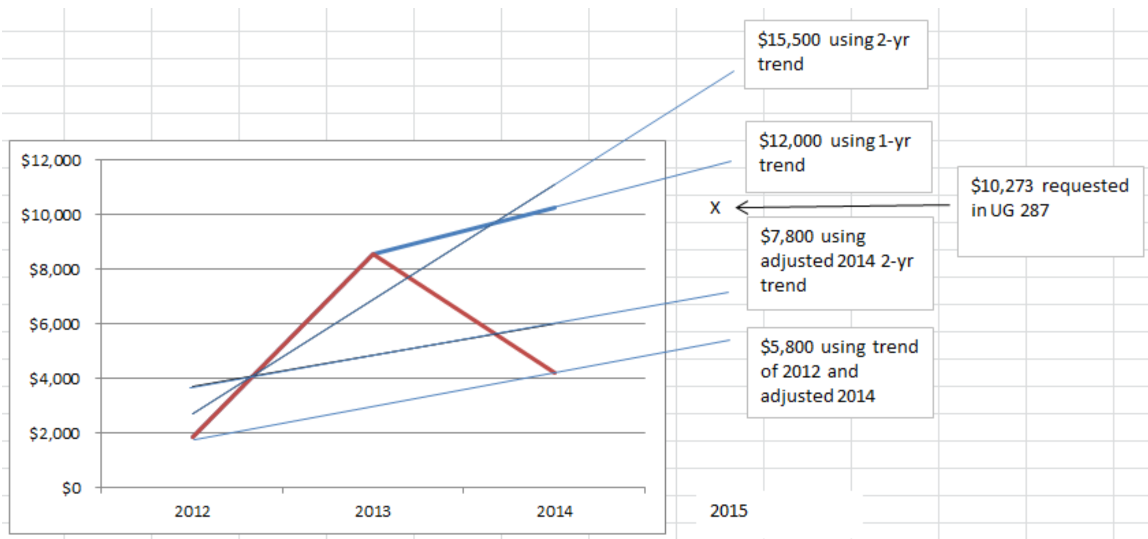
First, I obtained Cascade's actual other gas expense for 2012, 2013, and 2014 in response to DRs 195 and 196. I graphed the three years' expense to observe the expense pattern. The pattern is shown in the figure below with the red line from 2012 to 2013 and the blue line from 2013 to 2014.

Second, as reflected in the graph, other gas expense is lower in 2013 than in 2012 and 2014. In response to DR 193, Cascade explained that the amounts reported in 2013 and 2014 more accurately reflect the expenditure level in FERC 813 as compared to 2012. In 2014 there was a purchase made for some software maintenance totaling $20,941.32, of which $6,088.74 was allocated to Oregon.

Third, based on Cascade's explanation that 2014 expenses included expense for a significant software purchase that was not representative of normal expense, I removed the cost of the software ($6,088.74) from 2014 expenses, which results in an adjusted actual expense of $4,185 for that year. I then re-graphed the results to observe the pattern (in the figure below this is depicted with the red line). As shown in the figure below, the adjustment for extraordinary expenses in 2014 greatly changed the expense pattern compared to the pre-adjusted 2014 expense pattern.

Fourth, after making the adjustment to 2014 expenses, 2013 expenses stand out as possibly also including extraordinary expenses. Cascade did not identify any 2013 extraordinary expenses.

Fifth, to eliminate the influence of the suspect 2013 expenses, I propose that the pattern represented by the 2012 expenses and 2014 adjusted expenses most closely aligns with on-going expenses. Using a straight-line trend of the 2012 and adjusted 2014 expenses, I conclude $5,800 is a reasonable amount to include as CNG's test year expense in this rate case.



Q. Please summarize your proposed adjustment to Other Gas Supply Expense.

A. I propose to reduce Cascade's requested $10,273 by $4,473 to $5,800.

<u>Issue: Underground Storage Expense (FERC Accounts 814-837)</u>

Q. Please summarize Cascade's proposal related to underground storage expense.

A. No expenses in FERC accounts 814-837 are requested in this rate case.

Q. Please describe your proposed adjustment of underground storage expense.

A. Cascade does not propose an amount for underground storage expense, I therefore have no proposed adjustment.

<u>ISSUE: PURCHASED GAS EXPENSE</u>

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 this rate case at this time.

<u>ISSUE: IRP</u>

Q. Does Cascade make a proposal related to its IRP in this rate case?

A. No.

Q. Do you have an IRP related concern?

A. Yes. Cascade's staffing approach has created deficiencies in its ability to perform its required regulatory IRP activities. My specific example comes from the 2014 IRP preparation process. On May 6, 2015, Cascade filed a request under OAR 860-027-0400(3) to extend the filing date of its 2014 IRP from May 29, 2015, to July 17, 2015. The Commission had previously issued Order

No. 14-054 on February 18, 2014, extending the filing date from August 14, 2014, to February 11, 2015, and issued Order No. 14-303 on September 2, 2014, extending the filing date from February 11, 2015, to May 29, 2015.

Cascade filed its most recent request for an extension due to a medical emergency that impacted a key Cascade employee and halted its progress to finalize its draft 2014 IRP. I am concerned that a medical emergency impacting a single employee could cause such a delay with its 2014 IRP filing.

Q. Please describe your proposed adjustment related to the IRP.

A. I propose that Cascade evaluate its staffing approach and changes be made where needed, to ensure that its required regulatory IRP activities are performed on schedule and in compliance with Commission requirements.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 287
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

July 31, 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 287
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

July 31, 2015

Exhibit Staff/402 Colville

From DR58 Response file name "A58_Revised.xlsx"

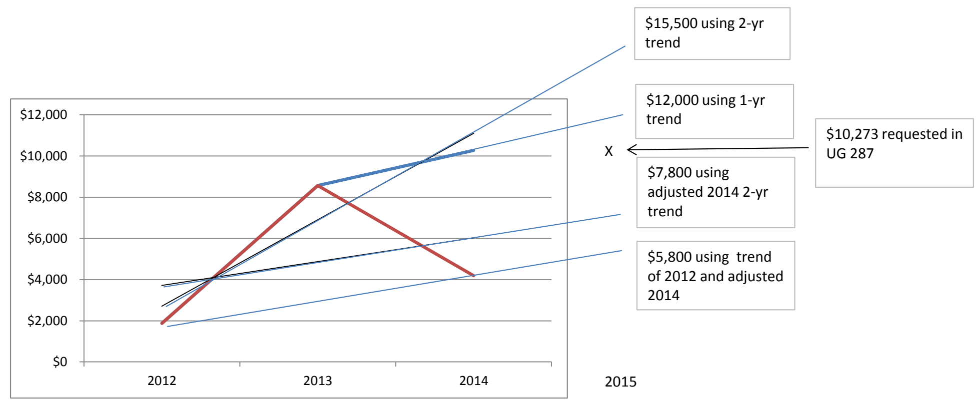
FERC ACCOUNTS	Oregon SS Total	2014 Oregon Sorted	Rounding Error
813	10,273.37	10,273.36	0.01

FERC ACCOUNTS	Oregon SS Total	2013 Oregon Sorted	Rounding Error
813	8,567.37	8,567.42	(0.05)

FERC ACCOUNTS	Oregon SS Total	2012 Oregon Sorted	Rounding Error
813	1,879.08	1,879.08	0.00

From DR58 Response file name "A58_Revised.xlsx"

Other Gas Expense	2012	2013	2014	2015
	$1,879	$8,567	$10,273	0
"One-Time" Adjustment			$6,089	
	$1,879	$8,567	$4,185	$0



From DR 193 Response:

Cascade feels that the amounts reported in 2013 & 2014 more accurately reflect the expenditure level in FERC 813 as compared to 2012. In 2014 there was a purchase made for some software maintenance totaling $20,941.32 of which $6,088.74 was allocated to Oregon.

From DR 196 Response:

Please see response to Staff Data Request 195 for calendar year 2014 for amount requested to be included in this rate request. No adjustment is being proposed to the base year amount for Other Gas Supply Expenses.

CASE: UG 287
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

July 31, 2015

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

A. My name is Linnea Wittekind. 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/501.

Q. What is the purpose of your testimony?

A. I recommend removal of costs appropriately allocated to Washington and discuss my review of other expense included in Cascade's rate case.

Q. Did you prepare an exhibit for this docket?

A. Yes. In addition to my witness qualification statement, I prepared Exhibit Staff/502, which is the Company's response to Staff Data Request 190.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Pipeline Inspection Cost Adjustment

Q. Please explain the pipeline inspection cost adjustment.

A. The Pipeline Inspection Cost Adjustment is an operation and maintenance (O&M) expense associated with distribution. In this case, the Company proposed an adjustment to increase costs associated with pipeline inspections over and above those already performed on an annual basis[1].

Q. How much is the Pipeline Inspection Cost Adjustment for?

A. The Pipeline Inspection Cost Adjustment is $205,548.[2]

Q. Does Staff recommend allowing the Pipeline Inspection Cost Adjustment?

A. No. According to the Company, the Pipeline Inspection Cost Adjustment is only allocable to Washington, not Oregon.[3]

Q. Do you propose any other adjustments to Distribution O&M?

A. No.

[1] *See* CNG/300/Parvinen/6-7.
[2] *See* CNG/300/Parvinen/7.
[3] See Staff Exhibit 502, copy of Company's response to Staff data request no. 190.

Issue 2, Other Issues

Q. Did you review any other issues?

A. Yes. In addition to reviewing Distribution O&M expenses (FERC Accounts 700 -897), I also reviewed customer operation expenses (FERC Accounts 901-916), gains on sales of utility property, and taxes other than income.

Q. Did you make any adjustments to the additional areas reviewed?

A. No.

Q. Please explain your analysis of customer operation expenses.

A. Cascade includes $4.7 million in test year revenue for customer operation expense. I reviewed trends in costs as well as transaction level detail for expenses that are not allowable for rate recovery. Customer operation expenses include expenses for meter reading, billing and collection as well as customer service included in FERC Accounts 901 - 916. Cascade maintains separate meter reading personnel in Washington and Oregon and I did not identify any cross-subsidization.

Cascade's costs for customer service and customer billing are allocated. I reviewed Cascade's allocated costs for both cost categories over the last several years, and Cascade's 2015 forecast for these costs are consistent with Cascade's historic costs. Staff witness Matt Muldoon will testify regarding Cascade's allocation methodology.

Customer operation accounts also includes costs for items such as meals and entertainment expenses. Staff witness Brian Bahr reviewed these expenses and has proposed an adjustment in Staff/700.

I also reviewed the annual total of customer operation expenses from 2012 to 2014 as well as what are forecasted for 2015 and did not find a substantial increase in expenses.

Q. Please explain your analysis of gains on utility property.

A. As for the gains on sales of utility property, there were not any gains or losses associated with the disposition of property that were deferred for later inclusion in rates. As explained in Order No. 12-286, Cascade does not currently have a property sales deferred account. Instead to be consistent with previous treatment of Cascade property sales, and with the proposed treatment by the Washington Utility and Transportation Commission, Staff routinely recommends Oregon's portion of gain be applied to depreciate reserves to offset costs associated with the acquisition of new property. Similar treatment concerning Cascade property was authorized by the Commission in Order No. 10-047 (UP 256) and Order No. 10-301 (UP 262).

Q. Please explain your analysis taxes other than income.

A. Taxes other than income include taxes such as county taxes, property taxes and payroll taxes. In reviewing these taxes, I analyzed annual tax amounts from years 2012 through 2014 as well as those forecasted for 2015. I did not note any out of period expense.

Q. How many data requests did you review as part of your analysis?

A. I reviewed 14 multi-part standard data requests and seven follow up data requests.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 287
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

July 31, 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 287
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

July 31, 2015

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 190

Date prepared: 5/30/2015

Preparer: Michael Parvinen

Contact: Pamela Archer

Telephone: (509)-734-4591

190. Please provide in an Excel spreadsheet a detailed breakout of the "Pipeline Inspection Cost Adj" of $205,548 included in the rate case in CNG/300/Parvinen/6-7.

   a. How long in years does Cascade expect these costs to occur?
   b. When did the Pipeline Inspection Cost Adj begin?
   c. According to CNG/300/Parvinen/7 at 1 – 2, "It is anticipated that these additional costs will continue for several years". Please explain in detail the reasons Cascade believes these costs will continue. Provide proof if available.

Response:

Upon further review it was determined that the identified costs are Washington state specific. The same program is planned for Oregon but may not be implemented in the test period. Cascade will remove this adjustment in its rebuttal testimony.

CASE: UG 287
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

July 31, 2015

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

A. My name is Mitchell Moore. 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/601.

Q. What is the purpose of your testimony?

A. I demonstrate that the Company has not met the requirements contained in the Oregon Administrative Rules to support including some of its advertising expenses in the revenue requirement. Accordingly, I recommend an adjustment that reduces the test year for advertising expenses by $96,000.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/602, consisting of 4 pages. This exhibit contains Company responses to data requests. I also prepared Exhibit Staff/603, an Excel file that also contains data request responses.

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. Does the Commission have a standard means of defining how advertising-related expenses are treated?

A. Yes, it does. OAR 860-026-0022 sets out how advertising-related expenses are addressed in a rate case. Each type of advertising expenses is classified by category (Categories A-E), and each category has a different standard for inclusion in rates that is applied by the Commission.[1]

Cascade does not specify categories for its advertising expense in its rate filing. However the Company's actual expenses in 2014 all belonged to either Category A or Category C.[2] Accordingly, Staff uses these categories to analyze Cascade's advertising expenses in this docket.

Category A expenses are for utility service advertising expenses and utility information advertising expense.[3] 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.[4]

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]."[5] 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

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[1] OAR 860-026-0022.
[2] Staff Exhibit 603, Cascade response to DR Nos. 243-244
[3] OAR 860-026-0022(2)(a).
[4] OAR 860-026-0022(3)(a).
[5] OAR 860-026-0022(2)(c).

and ORS 759.180, the utility shall separately state the amount of advertising expenses in Category C.

Q. What amount of advertising expenses does Cascade include in its 2015 test year?

A. It is not clear. The initial filing and accompanying workpapers subsume advertising expenses within Administrative and General (A&G) expenses. I was unable to discern what portion of A&G expenses is attributable to advertising. However, Cascade did provide its 2014 actual expense for advertising, as well as its system-wide budgeted expense for 2015, which is based on an escalation from its 2014 base year budget. If Cascade's revenue requirement is based on Cascade's 2015 system-wide budget, using its stated allocation factor of 24.3 percent, Cascade includes approximately $96,000 for advertising in the test year revenue requirement. However, if Cascade's revenue requirement is based on historical spending in 2013 and 2014, the Company includes approximately $106,000. If based on the Company's system-wide budget and using the actual allocation used in 2013-2014, the Company includes approximately $118,000.

Q. How did Staff perform its analysis of Cascade's proposed advertising expenses?

A. I reviewed the Company's response to a Standard Data Request, to which it provided only a partial response.[6] I then followed up with several additional data requests for a complete response to the standard data request,

[6] Staff Exhibit 602, Cascade response to SDR No. 104.

transaction-level detail of advertising expense in the 2014 base year, additional budgeting information, as well the rationale that would support including some types of advertising expense in the rates.

Q. How did the Company budget advertising expenses for the 2015 test year?

A. Cascade did not provide test year expenses broken down by category for Oregon, as was requested in the standard data request and followup data requests. The only Company-provided information for the test year was system-wide budget information. For the base year, 2014, the Company did provide expenses broken down by category. The Company increased its 2014 system-wide budget by using an escalation factor of 2.5%. On a system-wide basis, the Company proposes the following budget for the test year:

Object Account	Description	2015 Estimate Total Company
5711	Radio Advertising	20,491.82
5712	Newspaper Advertising	15,682.50
5713	Television Advertising	20,491.80
5714	Co-Op Advertising	255,148.55
5715	Other Utility Advertising	47,228.93
5731	Marketing Incentives	10,250.00
5740	Public Information Meetings	26,650.01
	Total	**395,943.61**

[7]

If we apply the standard 24.3 percent allocation factor to the system-wide budget, the resulting Oregon allocation of advertising expenses equates to approximately $96,000. However, as noted above, in previous years Cascade

[7] See Staff/602, Cascade DR Response No. 246.

has allocated approximately 30 percent of advertising expenses to Oregon. Based on this historical treatment, the 2015 Oregon allocated budget is projected to be approximately $118,000.

Q. What is Staff's recommendation regarding Cascade's advertising expenses?

A. First, I recommend using 2014 actual expenses, escalated by the All-Urban CPI, as the basis for establishing the 2015 test year expense. Second, based on my review of transaction-level detail for advertising expenses in the 2014 base year, I believe that the majority of Cascade's advertising expense for 2015 should be removed from the test year. Most of Cascade's advertising expenses are Category C advertising expenses that the Company must, according to OAR 860-026-0022(3)(c), separately state and prove are just and reasonable for ratemaking purposes. The Company has not done so.

Q. Did Staff ask the Company to provide justification for inclusion of its Category C advertising in rates?

A. Yes. Both the Standard Data Request (#104), and a follow-up DR (#244) requested justification for including these expenses in rates. The Company did not do so.[8] In the absence of any evidence showing that the Company's Category C advertising expenses are just and reasonable for ratemaking purposes, Staff recommends excluding them from the Company's test year expense.

[8] See Staff Exhibit 602, response to DR No.104, and Staff Exhibit 603, response to DR Nos. 243-244.

Q. What is Staff's recommended adjustment for Cascade's 2015 Test Year Expense?

A. I include Cascade's Category A advertising expenses in Cascade's 2015 test year expense. I determine the Company's Category A advertising expenses using Cascade's actual 2014 expenses for this category ($22,000) escalated by the All-Urban CPI, which is generally used by the Commission as an escalation factor. However, the May 2015 Index is -.04, which has virtually no effect (~$100) on this adjustment.

As discussed above, Category A expenses are presumed reasonable if they are 0.125 percent or less of the gross retail operating revenues determined in the proceeding. The $22,000 for Category A advertising expenses satisfies that criteria.

I remove all other advertising expenses from Cascade's test year expense based on the assumption the remaining advertising expenses are Category C expenses. Based on Cascade's 2015 system-wide advertising budget, and the historical allocation to Oregon, this amount is approximately $96,000. However, as noted above, I am not sure what amount of advertising expenses Cascade included in its test year. But, any amount in addition to the $22,000 for Category A expenses should be removed.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 287
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

July 31, 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 design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UG 287
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 602

Exhibits in Support Of Opening Testimony

July 31, 2015

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 104

Date prepared: 01/30/2015

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509)734-4591

104. 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 period rates 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.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

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:

See attached spreadsheet **A104.xlsx** for item (e)

For items (a) through (d) and item (f)……N/A

A247

Cascade does not budget by Category. Below is the breakdown that Cascade budgets for.

Object Account	Description	2014 Budget Total Company
5711	Radio Advertising	19,992.02
5712	Newspaper Advertising	15,300.00
5713	Television Advertising	19,992.00
5714	Co-Op Advertising	248,925.41
5715	Other Utility Advertising	46,077.00
5731	Marketing Incentives	10,000.00
5740	Public Information Meetings	26,000.01
	Total	**386,286.44**

Object Account	Description	2014 Actual Total Company	2014 Actual Oregon Amount
5711	Radio Advertising	10,000.37	2,294.27
5712	Newspaper Advertising	1,706.45	526.35
5713	Television Advertising	-	-
5714	Co-Op Advertising	-	-
5715	Other Utility Advertising	302,171.33	70,333.16
5731	Marketing Incentives	-	-
5740	Public Information Meetings	39,589.03	32,429.79
	Total	**353,467.18**	**105,583.57**

Object Account	Description	2013 Budget Total Company
5711	Radio Advertising	200.00
5712	Newspaper Advertising	1,200.00
5713	Television Advertising	20,040.00
5714	Co-Op Advertising	-
5715	Other Utility Advertising	205,035.76
5731	Marketing Incentives	9,999.99
5740	Public Information Meetings	135,592.04
	Total	**372,067.79**

Object Account	Description	2013 Actual Total Company	2013 Actual Oregon Amount	
5711	Radio Advertising	-	-	
5712	Newspaper Advertising	5,711.90	822.11	
5713	Television Advertising	3,000.00	245.50	
5714	Co-Op Advertising	-	-	
5715	Other Utility Advertising	145,844.98	34,233.44	
5731	Marketing Incentives	-	-	
5740	Public Information Meetings	200,611.48	70,200.99	
	Total	**355,168.36**	**105,502.04**	0.05

CASE: UG 287
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603
(ELECTRONIC ONLY)

Exhibits in Support
Of Opening Testimony

July 31, 2015

Advertising Expenditures
January 1 - December 31, 2014

												nse by Internal Acct (IA) *(please extend number of IA columns as nec*			
							Category (as defined by OAR 860-026-0022(1) &(2))					Radio Advertising	Newspaper Advertising	Other Utility Advertising	Public Information Meetings
Item No	**Description**	**Description 2**	**Total Co**	**OR alloc**	**Or Situs**	**FERC Acct**	**A**	**B**	**C**	**D**	**E**	**5711**	**5712**	**5715**	**5740**
1	iPROMOTEu	LUMINESQUE PENS	653.18	158.72		908			X					X	
2	NBS PROMOS, INC.	Key Ring, Barrel Squeezies (811 Advertising)	770.29	187.18		908	X							X	
3	S VOLK 4-14	E-gift cards	45.00	10.94		908			X					X	
4	S VOLK 4-14	E-gift cards	25.00	6.08		908			X					X	
5	NBS PROMOS, INC.	Stress Reliever, Excavator (811 Advertising)	4,971.21	1,208.00		908	X							X	
6	DEX MEDIA WEST INC	Kitsap County	1,258.05	305.71		908			X					X	
7	Valpak of Western Washington W	598,914 Postcards	41,804.74	10,158.55		908			X					X	
8	Valpak of Western Washington W	Postage for Postcards	113,502.35	27,581.07		908			X					X	
9	SANDER RESOURCES, LLC	Sponsorship of 2014 811 Day Nationwide Media Effort	2,000.00	486.00		908	X							X	
10	CGA	CALIFORNIA CHROME SPONSORSHIP (811 Advertising)	1,000.00	243.00		908	X							X	
11	S VOLK 6-14	Starbucks cards	25.00	6.08		908			X					X	
12	S VOLK 6-14	Starbucks cards	10.00	2.43		908			X					X	
13	S VOLK 6-14	Starbucks cards	45.00	10.94		908			X					X	
14	S VOLK 6-14	Starbucks cards	45.00	10.94		908			X					X	
15	S VOLK 6-14	Starbucks cards	45.00	10.94		908			X					X	
16	S VOLK 7-14	Kindle Fire	183.03	44.48		908			X					X	
17	S VOLK 8-14	Cake Decor	34.42	8.36		908			X					X	
18	S VOLK 8-14	Fruit Tray/Ice Cream	27.12	6.59		908			X					X	
19	S VOLK 8-14	Frosting for cake	5.85	1.42		908			X					X	
20	DEX MEDIA WEST INC	Kitsap County	3,041.69	739.13		908			X					X	
21	DEX MEDIA WEST INC	Kitsap County	1,541.98	374.70		908			X					X	
22	S VOLK 10-14	Starbucks Cards	2,500.00	607.50		908			X					X	
23	DEX MEDIA WEST INC	Kitsap County	1,521.28	369.67		908			X					X	
24	NBS PROMOS, INC.	Football, Plastic 6" (811 Advertising)	1,703.99	414.07		908	X							X	
25	iPROMOTEu	Javelina Corporate & Micro Sticky Book (811 Advertising)	2,577.43	626.32		908	X							X	
26	REVAK & ASSOCIATES	Shirts (811 Advertising)	17,085.41	4,151.75		908	X							X	
27	EAGLE PRINTING	NOTEPADS (811 Advertising)	321.02	78.01		908	X							X	
28	S VOLK 11-14	$5 Starbucks Cards	2,500.00	607.50		908			X					X	
29	S VOLK 11-14	2 - IPads	1,082.98	263.16		908			X					X	
30	DEX MEDIA WEST INC	Kitsap County	1,500.00	364.50		908			X					X	
31	JJ HARRISON, LLC	Anti-bullying assembly @ Stevens Middle School (811 Advertising)	500.00	121.50		908	X							X	
32	S VOLK 12-14	Mailing Supplies	126.51	30.74		908			X					X	
33	S VOLK 12-14	Mailing Supplies	103.84	25.23		908			X					X	
34	DEX MEDIA WEST INC	Kitsap County	1,500.00	364.50		908			X					X	
35	First Night Tri-Cities	Sponsorship of First Night Festival	1,000.00	243.00		908			X					X	
36	W WALKER 6-14	Fund Raiser Event	425.00		425.00	908			X						X
37	S POTJE 1-14	Mid OR Const Safety Summit	1,500.00		1,500.00	908			X						X
38	J STAUDENMAIER 2-14	Public Awareness	1,500.00		1,500.00	908			X						X
39	Central Oregon Classic Chevy C	2014 Flashback Cruz & vendor space (811 Advertising)	600.00		600.00	908	X								X
40	COSHA - SKILLS DEMO	Sponsorship Oregon Skills Demo & Safety Conference	600.00		600.00	908			X						X
41	KOHD	Bend OR	176.00		176.00	908			X						X
42	ZOLO MEDIA	Bend OR	816.00		816.00	908			X						X
43	K SIMPSON 4-14	Purchase of 500 baseballs (811 Advertising)	1,500.00		1,500.00	908	X								X
44	K SIMPSON 4-14	Purchase of 500 baseballs (811 Advertising)	1,642.63		1,642.63	908	X								X
45	W WALKER 4-14	Meal	39.75		39.75	908			X						X
46	S POTJE 4-14	Pacific Marketing	1,194.73		1,194.73	908			X						X
47	S POTJE 4-14	COBA	930.00		930.00	908			X						X
48	OREGON UTILITY NOTIFICATION CE	2014 OUNC Matching Media Ad Campaign	1,000.00		1,000.00	908			X						X
49	DAVIESMOORE	Safe Digging Radio Campaing (811 Advertising)	218.75		218.75	908	X								X
50	DAVIESMOORE	Cascade Gas - Spring '14 Radio	935.00		935.00	908			X						X
51	iPROMOTEu	Shirts (811 Advertising)	3,388.04		3,388.04	908	X								X
52	DAVIESMOORE	Cascade Gas - Spring '14 Radio	3,740.00		3,740.00	908			X						X
53	iPROMOTEu		3,397.09		3,397.09	908			X						X
54	iPROMOTEu	TABLE COVERS	1,149.00		1,149.00	908			X						X
55	DAVIESMOORE	Cascade Gas - Spring '14 Radio	330.00		330.00	908			X						X
56	J STAUDENMAIER 7-14	811 Night at the park	400.00		400.00	908	X								X
57	PETTY CASH - ALECIA INGALLINER	JUL 2014 PETTY CASH	60.00		60.00	908			X						X
58	iPROMOTEu	side walls	1,494.44		1,494.44	908			X						X
59	FOX CENTRAL OREGON	Night at the Ball Park (811 Advertising)	410.00		410.00	908	X								X
60	PETTY CASH - ALECIA INGALLINER		20.00		20.00	908			X						X
61	PETTY CASH - ALECIA INGALLINER		94.95		94.95	908			X						X
62	Combined Communications, Inc	Night at the Ball Park (811 Advertising)	(658.75)		(658.75)	908	X								X
63	ZOLO MEDIA	Night at the Ball Park (811 Advertising)	780.00		780.00	908	X								X
64	HORIZON BROADCASTING GROUP LLC	Night at the Ball Park (811 Advertising)	1,000.00		1,000.00	908	X								X
65	Combined Communications, Inc	Night at the Ball Park (811 Advertising)	318.75		318.75	908	X								X
66	Combined Communications, Inc	Night at the Ball Park (811 Advertising)	361.25		361.25	908	X								X
67	Combined Communications, Inc	Night at the Ball Park (811 Advertising)	178.50		178.50	908	X								X
68	ROTARY CLUB OF GREATER BEND	AD (811 Advertising)	400.00		400.00	908	X								X
69	KOHD	Night at the Ball Park (811 Advertising)	220.00		220.00	908	X								X
70	A INGALLINERA 10-14	SPONSORSHIP	100.00		100.00	908			X						X
71	Sisters Little League	Public Awareness 811 signage for 2015 (811 Advertising)	1,000.00		1,000.00	908	X								X
72	Ingallinera, Alecia Petty Cash	REIMBURSE PETTY CASH	100.00		100.00	908			X						X
73	S POTJE 7-14	Pro Golf	100.00		100.00	908			X						X
74	S POTJE 7-14	EDCO	40.00		40.00	908			X						X
75	First Night Tri-Cities	Sponsorship of First Night Festival	1,500.00	364.50		908			X						X
76	UPPER YAKIMA VALLEY UTILITY CO	811 LOGO TABLECLOTH (811 Advertising)	278.94	67.78		908	X								X
77	CEDC	Platinum Sponsorship CEDC Annual Meeting	500.00	121.50		908			X						X
78	S MCELHINNEY 11-14	Attendance Fee	15.00	3.65		908			X						X
79	S MCELHINNEY 11-14	Attendance Fee	15.00	3.65		908			X						X
80	Bicoastal Media, LLC	Call 811 Before You Dig Ads	249.00	60.51		909	X					X			
81	Bicoastal Media, LLC	Call 811 Before You Dig Ads	249.00	60.51		909	X					X			
82	Cascade Radio Group	Earth Day Ad	1,000.00	243.00		909	X					X			
83	Bicoastal Media, LLC	Call 811 Before You Dig Ads	289.00	70.23		909	X					X			
84	Cascade Radio Group	Coat Drive	750.00	182.25		909			X			X			
85	Bicoastal Media, LLC	Call 811 Before You Dig Ads	289.00	70.23		909	X					X			
86	Bicoastal Media, LLC	Call 811 Before You Dig Ads	200.00	48.60		909	X					X			
87	Bicoastal Media, LLC	Call 811 Before You Dig Ads	150.00	36.45		909	X					X			
88	Townsquare Media West Central	Call 811 Before You Dig Ads	1,150.00	279.45		909	X					X			
89	Bicoastal Media, LLC	Call 811 Before You Dig Ads	99.50	24.18		909	X					X			
90	Bicoastal Media, LLC	Call 811 Before You Dig Ads	1,539.00	373.98		909	X					X			
91	K MCCAULEY 12-14	Advertisement	600.00	145.80		909			X				X		
92	AG-NEWS	1/2 SPACE ORDERED	895.00	217.49		909			X				X		
93	Bend Sunrise Lions Club	2014 DEMO DERBY PROGRAM AD (811 Advertising)	250.00		250.00	909	X							X	
94	T BEACH 6-14	Office Materials	91.30	22.19		909			X					X	
95	M KINGERY 12-14	Facebook	2.19	0.53		909			X					X	
96	M KINGERY 10-14	Facebook Promotion	6.92	1.68		909			X					X	
97	M KINGERY 11-14	Facebook Promotion	7.28	1.77		909			X					X	
98	M KINGERY 9-14	Facebook	3.90	0.95		909			X					X	
99	M KINGERY 8-14	Outage Notification	11.80	2.87		909			X					X	
100	M KINGERY 8-14	Annual Subscription	36.13	8.78		909			X					X	
101	M KINGERY 7-14	Facebook Promotions	1.92	0.47		909			X					X	
102	M KINGERY 6-14	Facebook posting	9.10	2.21		909			X					X	
103	M KINGERY 6-14	facebook posting	17.78	4.32		909			X					X	
104	M KINGERY 4-14	Facebook Promotion	7.27	1.77		909			X					X	
105	A MARTIN 12-14	Phone Listings	557.00	135.35		909			X					X	
106	A MARTIN 12-14	Phone Listings	10.51	2.55		909			X					X	
107	A MARTIN 11-14	Phone Listings	1,032.00	250.78		909			X					X	
108	A MARTIN 11-14	Phone Listings	12.36	3.00		909			X					X	
109	A MARTIN 11-14	Phone Listings	10.51	2.55		909			X					X	
110	A MARTIN 9-14	Phone Listings	3,131.76	761.02		909			X					X	
111	A MARTIN 10-14	Phone Listings	649.60	157.85		909			X					X	
112	A MARTIN 10-14	Phone Listings	46.53	11.31		909			X					X	
113	A MARTIN 10-14	Phone Listings	24.00	5.83		909			X					X	
114	A MARTIN 10-14	Phone Listings	37.08	9.01		909			X					X	
115	A MARTIN 8-14	Phone Listings	231.00	56.13		909			X					X	

116	A MARTIN 8-14	Phone Listings	1,071.00	260.25		909			X					X	
117	A MARTIN 8-14	Line Listings	12.28	2.98		909			X					X	
118	A MARTIN 7-14	Phone Listings	49.44	12.01		909			X					X	
119	A MARTIN 6-14	Phone Listings	2,216.80	538.68		909			X					X	
120	A MARTIN 6-14	Phone Listings	735.00	178.61		909			X					X	
121	A MARTIN 6-14	Phone Listings	1,944.00	472.39		909			X					X	
122	A MARTIN 5-14	Phone Listings	1,580.00	383.94		909			X					X	
123	A MARTIN 5-14	Phone Listings	777.00	188.81		909			X					X	
124	A MARTIN 5-14	Phone Listings	231.00	56.13		909			X					X	
125	A MARTIN 4-14	Phone Listings	1,643.05	399.26		909			X					X	
126	A MARTIN 4-14	Phone Listings	1,643.05	399.26		909			X					X	
127	A MARTIN 3-14	Phone Listings	24.72	6.01		909			X					X	
128	A MARTIN 2-14	Phone Listings	1,182.00	287.23		909			X					X	
129	A MARTIN 2-14	Phone Listings	12.36	3.00		909			X					X	
130	M KINGERY 2-14	Web Promotion	1.64	0.40		909			X					X	
131	A MARTIN 1-14	Phone Listings	902.00	219.19		909			X					X	
132	COLUMBIA CENTER	NOV LEASE RENT	487.50	118.46		909			X					X	
133	COLUMBIA CENTER	OCT LEASE	487.50	118.46		909			X					X	
134	BRITTEN SERVICES	Banner for Columbia Center	103.97	25.26		909			X					X	
135	COLUMBIA CENTER	Rent	487.50	118.46		909			X					X	
136	COLUMBIA CENTER	Rent	975.00	236.93		909			X					X	
137	BRITTEN SERVICES	Banner for Columbia Center	104.86	25.48		909			X					X	
138	Mountain View High School, Yea	AD YEAR BOOK	90.00		90.00	909			X						X
139	K MCCAULEY 3-14	Advertising	135.00		135.00	913			X					X	
140	Pendleton Babe Ruth	CNG banner	250.00		250.00	913			X					X	
141	MARGIE BROWN	Window Painting	70.00		70.00	913			X					X	
142	HUNTINGTON LION CLUB	Ad for Catfish Derby	50.00		50.00	913			X					X	
143	LONGVIEW DAILY NEWS		(1,287.80)	(312.94)		921			X				X		
144	J SILVEIRA 2-14	Outreach Promo	4,861.00	1,181.22		921			X					X	
145	M KINGERY 3-14	Web Promotion	6.44	1.56		921			X					X	
146	E&M Consulting, Inc.	2013-14 SICBA member directory (811 Advertising)	699.00	169.86		921	X							X	
147	A SARGENT 2-14	Oven Mitts	453.50	110.20		921			X					X	
148	ENERGY SOLUTIONS CENTER	2014 Spring Edition of Natural Living Magazine	675.00	164.03		921			X					X	
149	LYNDEN TRIBUNE	BIA directory book ad	425.00	103.28		921			X					X	
150	SKYLINE PACIFIC NORTHWEST	WINDSCAPE TT & THROW	1,874.12	455.41		921			X					X	
151	A SARGENT 8-14	Outreach Photos	47.65	11.58		921			X					X	
152	ENERGY SOLUTIONS CENTER	2014 Fall Edition of Natural Living Magazine	390.00	94.77		921			X					X	
153	S MCELHINNEY 9-14	Propane	6.45	1.57		921			X					X	
154	A SARGENT 9-14	Paper	1.52	0.37		921			X					X	
155	A SARGENT 9-14	Paper	17.38	4.22		921			X					X	
156	A SARGENT 9-14	Parade of Homes&Columbia Mall	52.10	12.66		921			X					X	
157	A SARGENT 9-14	Parade of Homes&Columbia Mall	52.09	12.66		921			X					X	
158	A SARGENT 9-14	Outreach Supplies	8.61	2.09		921			X						X
159	T BEACH 4-14	Public Awareness	88.02	21.39		921			X						X
160	REVAK & ASSOCIATES	Shirts (811 Advertising)	1,876.82	456.07		921	X								X
161	REVAK & ASSOCIATES	Shirts (811 Advertising)	677.50	164.63		921	X								X
162	TOWNSQUARE MEDIA - TRI CITIES		1,133.33	275.40		930.1			X			X			
163	TOWNSQUARE MEDIA - TRI CITIES	contract 20910	296.00	71.93		930.1			X			X			
164	TOWNSQUARE MEDIA - TRI CITIES	contract 41146	249.00	60.51		930.1			X			X			
165	TOWNSQUARE MEDIA - TRI CITIES	contract 41144	454.00	110.32		930.1			X			X			
166	TOWNSQUARE MEDIA - TRI CITIES		16.07	3.91		930.1			X			X			
167	TOWNSQUARE MEDIA - TRI CITIES	CONT 10836&40869	1,328.47	322.82		930.1			X			X			
168	Town and Country Advertising	Acct 20856-New Years ad	68.00		68.00	930.1			X				X		
169	Town and Country Advertising	ACCT 20856	68.00		68.00	930.1			X				X		
170	Town and Country Advertising	Acct 20856	68.00		68.00	930.1			X				X		
171	Town and Country Advertising	Acct 20856	68.00		68.00	930.1			X				X		
172	TOWN & COUNTRY ADVERTISING	Acct 20856-Memorial Day	68.00		68.00	930.1			X				X		
173	Town and Country Advertising	ACCT 20856	68.00		68.00	930.1			X				X		
174	Town and Country Advertising	Acct 20856-New Years promo	68.00		68.00	930.1			X				X		
175	Central Oregon Builders Associ	HOLE SPONSOR	150.00		150.00	930.1			X					X	
176	MDUR 12-2014	MDU Resources expenses	778.12	189.08		930.1			X					X	
177	ETS 12-2014	ETS Charges	65.94	16.02		930.1			X					X	
178	MDUR 11-2014	MDU Resources expenses	367.85	89.39		930.1			X					X	
179	MDURJE 10-2014	MDU Resources expenses	2,582.23	627.48		930.1			X					X	
180	MDUR 09-2014	MDU Resources expenses	959.36	233.12		930.1			X					X	
181	MDUR 08-2014	MDU Resources expenses	1,711.59	415.92		930.1			X					X	
182	MDUR JE 07-2014	MDU Resources expenses	8,177.80	1,987.21		930.1			X					X	
183	MDUR JE 06-204	MDU Resources expenses	768.56	186.76		930.1			X					X	
184	MDUR 05-2014	MDU Resources expenses	704.62	171.22		930.1			X					X	
185	MDUJR 04-2013	MDU Resources expenses	1,078.64	262.11		930.1			X					X	
186	MDURJE 03-2013	MDU Resources expenses	616.20	149.74		930.1			X					X	
187	MDURJE 02-2014	MDU Resources expenses	894.40	217.34		930.1			X					X	
188	MDURJE 01-2014	MDU Resources expenses	1,125.07	273.39		930.1			X					X	
189	MDURJE 01-2014	MDU Resources expenses	(1,125.07)	(273.39)		930.1			X					X	
190	MDURJE2 01-2014	MDU Resources expenses	1,125.07	273.39		930.1			X					X	
191	R HARRIS 6-14	United Way Event Sponsor	3,500.00	850.50		930.1			X					X	
192	HOME BUILDERS ASSOCIATION	ACCT CASCADE NATU RECEP 2014	1,500.00	364.50		930.1			X					X	
193	Tri-City Dust Devils	outfield fence sign	14,500.00	3,523.50		930.1			X					X	
194	COLUMBIA CENTER	NOV LEASE RENT	487.50	118.46		930.1			X					X	
195	COLUMBIA CENTER	OCT LEASE	487.50	118.46		930.1			X					X	
196	BRITTEN SERVICES	Banner for Columbia Center	103.97	25.26		930.1			X					X	
197	COLUMBIA CENTER	Rent	487.50	118.46		930.1			X					X	
198	HOME BUILDERS ASSOCIATION	CASCADE NATU - GOLD SPONSOR	500.00	121.50		930.1			X					X	
199	BELLINGHAM WHATCOM C OF C	ACCT 1143 7-4 MAIN STAGE SPONS	2,500.00	607.50		930.1			X					X	
200	Skagit/Island Counties Builder	bronze sponsor	1,000.00	243.00		930.1			X					X	
201	ENERGY SOLUTIONS CENTER	video branding	1,000.00	243.00		930.1			X					X	
202	BRITTEN SERVICES	Banner for Columbia Center	104.87	25.48		930.1			X					X	
203	COLUMBIA CENTER	Rent	975.00	236.93		930.1			X					X	
etc															

A243

a) 811 Advertising - $21,650.46

b)

70,092,488	Operating Revenues
0.125%	
87,616	Category 'A' Limit

c) N/A

d) None

e) See table above.

f)

CASE: UG 287
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

July 31, 2015

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/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to specific issues in Cascade Natural Gas Company's (Cascade or Company) request for general rate revision. Staff responds to the issues of pension costs, medical benefits, affiliated interests, administrative and general (A&G) expenses, and utility plant and capital additions.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/702, consisting of 54 pages, Confidential Exhibit Staff/703, consisting of 1 page, Exhibit Staff/704, and Exhibit Staff/705. Exhibits Staff/704 and Staff/705 are provided in electronic format only. 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:

Issue 1, Pensions

Q. How are pension costs typically treated by the Commission?

A. Though most expenses approved for inclusion in rates are based on cash costs, 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 is currently conducting a general investigation into the recovery of pension costs in Docket No. UM 1633. In that docket, the Commission is investigating 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.

Q. Please describe the Company's request regarding pension costs.

A. The Company's proposed revenue requirement includes the 2014 base year pension expense of $359 thousand on a total company basis, which is approximately $87 thousand on an Oregon-allocated basis.[1] The Company's

[1] Exhibit Staff/702, Bahr/1-3. Company's response to Staff Data Request No. 59.

use of the 2014 base year amount is notable because the Company's estimated test year pension expense is $612 thousand.[2]

The Company also includes in rate base its estimated prepaid pension asset, net of its related accumulated deferred taxes.[3] 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 includes in the test year rate base the December 31, 2014, balance of the prepaid pension asset, net of the estimated $1.9 million of accumulated deferred taxes associated with it, of approximately $2.9 million (Oregon allocated).[4]

Q. How did Staff analyze the Company's requested pension costs?

A. Staff reviewed the Company's responses to nine Staff data requests related to pension costs as well as the testimony and supporting work papers included in the Company's filing. Staff also met with the Company to discuss aspects of its pension costs. In analyzing the Company's requested pension costs, Staff distinguished between the two parts of the proposed cost, the requested FAS 87 expense amount and the inclusion in rate base of both the prepaid pension asset and the related accumulated deferred taxes.

As described above, the Commission has historically relied on FAS 87 expense as a reasonable representation of cash costs in any given year. The

[2] Exhibit Staff/702, Bahr/4. Company's response to Staff Data Request No. 131.
[3] *See* CNG/300, Parvinen/6, at 21.
[4] *See* Parvinen WP 301-304 (3), tab "Pension Asset Adjustment."

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 (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.

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 NW Natural (Docket No. UG 221), PacifiCorp (Docket No. UE 263), Avista (Docket Nos. UG 246 and UG 288), 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 has recommended in each case that no change to current cost recovery methods is warranted until the conclusion of the general investigation.

As the balance of a prepaid pension asset grows, so also grows the balance of its associated deferred tax benefit. As discussed fully in Commission Docket No. UM 1633, though no companies in Oregon currently receive recovery of their prepaid pension asset balances, at least one passes on to customers the benefit of the associated accumulated deferred taxes by including them (as a reduction) in rate base. Staff notes that Cascade currently includes neither its prepaid pension asset in rate base nor its associated deferred tax benefit.[5]

Q. What were Staff's findings on review of the Company's proposed FAS 87 expense?

A. 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 following table using 2014 SEC 10k filings found online. As seen in the below table, the Company's EROA was less than four of the other five companies' in both 2013 and 2014.

Table 1. Expected Rate of Return used in FAS 87 calculations

Company	**2013**	**2014**
Avista[6]	6.6%	6.6%
Cascade[7]	7%	7%
Idaho Power[8]	7.75%	7.75%
NW Natural[9]	7.5%	7.5%
PacifiCorp[10]	7.5%	7.5%

[5] Exhibit Staff/702, Bahr/5. Company's response to Staff Data Request No. 130.
[6] 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/1302, Bahr/6.
[7] 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/1302, Bahr/7.
[8] 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/1302, Bahr/8.
[9] 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/1302, Bahr/9.
[10] PacifiCorp's 2014 10k can be found online at: https://www.last10k.com/Search/LoadPDF?u=http://www.last10k.com/sec-

PGE[11]	8.25%	7.5%
AVERAGE	**7.43%**	**7.31%**

Because of the Company's lower EROA, Staff discussed at length with the Company its discretion in determining the EROA and the discount rate. The Company essentially relies on its third party actuary to determine its pension expense, and has little, if any, input about the EROA and discount rate that are used in the calculation. Because the Company had not yet received its updated report from its actuary at the time of its filing, the Company included in its revenue requirement only the FAS 87 amount from its base year. Staff finds this amount reasonable as it is significantly less than the test year estimate.

Q. What were Staff's findings on review of the Company's proposed inclusion in rate base of the prepaid pension asset, net of deferred taxes?

A. Consistent with recent practice and Commission decisions, Staff's position is that the Company's current pension cost recovery method should be maintained until a conclusion is reached in Docket UM 1633. Because that docket is still pending, Staff finds no basis for changing the Company's current pension cost recovery method.

Q. What adjustments does Staff propose to the company's proposed pension costs?

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filings/75594/000007559415000003/pacificorp123114form10-k.htm.pdf. Page 79 is included as Exhibit Staff/1302, Bahr/10.

[11] 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/1302, Bahr/11.

A. Staff proposes no adjustment to the Company's proposed FAS 87 pension expense. The Company relies on a third party actuary and has included only the actual 2014 FAS 87 expense rather than the estimated test year expense. With regard to the prepaid pension asset, Staff recommends removing it from rate base, as well as the associated deferred taxes.

Issue 2, Medical Benefits

Q. Please describe the Company's request regarding medical, dental, vision, and other benefits.

A. The Company has requested approximately $6.6 million in test year expenses relating to benefits.[12] 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 80/20 (employees pay 20 percent of premium costs and the Company pays 80 percent).

Q. Please describe the analysis performed by Staff.

A. Staff reviewed the Company's responses to seven Staff data requests as well as the Company's filing and supporting work papers. For its review, Staff first analyzed the overall historical trend in benefits costs and the Company's forecasted increase in premium amounts. Staff has observed a general trend of medical benefits costs have been increasing in recent years. This trend is common among companies and supported by term sheets of the benefits providers, which indicate generally higher premiums and rising health care costs.[13]

Staff also compared the Company's actual annual costs to budgeted costs for recent years and found that actual costs were overbudgeted in 2014 by six

[12] Exhibit Staff/702, Bahr/12-13. Company's response to Staff Data Request No. 63.
[13] Exhibit Staff/702, Bahr/14-20. Company's response to Staff Data Request No. 64.

percent, in 2013 by 29 percent, in 2012 by 35 percent, and under budgeted in 2011 by 13 percent.

Table 2. Benefits Actual Costs versus Budgeted[14]

	2011	2012	2013	2014
Actual	5,826,298	4,586,789	5,162,155	6,302,579
Budgeted	5,163,153	7,009,171	7,255,535	6,719,604
Difference	-13%	35%	29%	6%

One of the primary causes of the variance between actual and budgeted costs is pension and other post retirement costs. Because these costs depend on calculations influenced by fluctuations in the market, they are difficult to forecast with accuracy. However, the Company has demonstrated a propensity to overbudget, as evidenced by overbudgeting by 16 percent on average over the last four years.

In addition to analyzing historical trends and comparing actual historical costs to budgets, Staff also compared the Company's costs to industry averages. A survey found in the 2014 Kaiser Family Foundation publication indicates that the 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*

[14] Exhibits Staff/702, Bahr/12-13 and Bahr/21. Company's responses to Staff Data Request No. 63 and 253, respectively.

18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2013.“[15]

Staff typically proposes no adjustment to sharing between the Company and 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?

A. Yes. Though the Company’s premium sharing structure is reasonable compared to industry averages, and the historical trend of overall cost parallels trends of general medical cost increases throughout the country, Staff is concerned about the Company’s budgeted versus actual costs. Because the Company has over budgeted benefit costs by an average of 16 percent over the past four years, Staff recommends adjusting the Company’s proposed test year benefits by that same 16 percent. This results in a Staff-recommended decrease of $1,060,217 to the Company’s test-period projected cost of $6,626,359. The Staff-recommended test period medical benefits expense is $5,566,142.

[15] 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/702, Bahr/22.

Issue 3, Affiliated Interests

Q. Please describe the Company's request associated with affiliated interest costs.

A. The Company did not propose any costs specifically related to affiliated interests.

Q. How did Staff analyze the Company's requested affiliated interest costs?

A. Because the Company files an annual report on its affiliated interests, docketed as RG 44, this was Staff's primary resource in reviewing the Company's affiliated interest transactions and costs. Based on the report, the Company paid $12.5 million ($3.0 million on an Oregon-allocated basis) to affiliates in 2014. Its affiliates include MDU Resources Group Inc. (Cascade's parent company), Knife River Corporation (a subsidiary of MDU that provides asphalt services), Loy Clark Pipeline Company, Inc. (an indirect, wholly-owned subsidiary of MDU), and WBI (another indirect, wholly-owned subsidiary of MDU providing monitoring of Cascade's distribution system). The table below shows payments made to and from affiliates in 2014 by the Company.

Table 3. Payments To and From Affiliates by Cascade in 2014

Payments to:	**Total Company**	**Oregon Allocated**
MDU Resources Group Inc.	$12,541,495	$3,047,583
Knife River Corporation	$65,950	$65,950
Williston Basin Interstate Pipeline Company	$66,906	$16,258
Loy Clark Pipeline Company	$1,848	$1,848
Payments to:	**Total Company**	**Oregon Allocated**
Knife River Corporation	$46,503	$46,503

Staff compared the amounts paid and received by the Company in 2014 with those reported for 2013 and 2012. These figures are shown in the table below. The three year average of payments to affiliates (Oregon allocated) is $3,303,270 and from affiliates is $47,736.

Table 4. Payments To and From Affiliates by Cascade 2012-2014

Payments to Affiliates:	**Total Company**	**Oregon Allocated**
2014	$12,676,199	$3,131,639
2013	$10,976,852	$2,894,892
2012	$15,200,917	$3,883,281
Payments to Affiliates:	**Total Company**	**Oregon Allocated**
2014	$46,503	$46,503
2013	$40,288	$40,288
2012	$56,416	$56,416

Q. Does staff have any proposed adjustment related to affiliated interests?

A. No. Staff has no adjustment relating to affiliated interests.

Issue 4, Miscellaneous A&G

Q. Please describe the Company's request associated with miscellaneous A&G expenses.

A. The Company proposes including $3.4 million in revenue requirement for the 2015 test year A&G costs, which are escalated from 2014 actual amounts. The Company obtained its test year estimate by escalating 2014 actual amounts by 2.1 percent.[16]

Q. Please describe Staff's analysis and recommendations regarding the Company's requested A&G costs.

A. Staff commonly proposes certain adjustments related to A&G, supported by Commission precedent, and these issues are typically settled. Issues typically addressed by Staff as part of A&G are directors and officers (D&O) insurance, education and training, research and development (R&D), and miscellaneous expenses.

D&O Insurance-

Staff has recently begun proposing the removal of 50 percent of total D&O insurance, rather than 50 percent of only certain layers, to more appropriately reflect that the majority of claims brought against directors and officers are from shareholders rather than customers. According to a 2012 Towers Watson survey, "Consistent with our last three reports, derivative shareholder/investor suits continue to lead the types of claims filed over the last 10 years."[17]

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[16] *See* Parvinen WP 301-304 (3), tab "Inflation Factor."
[17] Exhibit Staff/702, Bahr/23. Page 19 of the Towers Watson Directors and Officers Liability Survey 2012 Summary of Results, found online here: http://www.towerswatson.com/en-US/Insights/IC-

Although the Company has not had any claims brought against any of its directors or officers since at least 2007,[18] any suit brought against them would more likely be brought by shareholders rather than customers.

To analyze D&O insurance costs, Staff obtained from the Company its estimated D&O insurance costs for the test year and its actual costs for the three preceding years.[19] Staff reviewed the overall trend of the costs, noting that the cost decreased from 2012 to 2013 and again from 2013 to 2014. Per inquiry into the downward trend, the Company explained that the trend was due primarily to changes in premiums and in corporate allocations.[20] Staff was unable to compare actual costs to budgeted costs, as the Company responded to a Staff data request that yearly budget information was not available.[21]

Staff notes that the Company's proposed 2015 cost is higher than in recent years. Commission precedent supports sharing of costs between ratepayers and shareholders.[22] Staff's proposal to remove 50 percent of premiums costs is based on findings indicating that the majority of claims brought against directors and officers are brought by shareholders, rather than ratepayers, and customers have no say in electing a company's directors or officers; therefore, it is reasonable that customers should not bear the majority

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Types/Survey-Research-Results/2013/03/Directors-and-Officers-Liability-2012-Survey-of-Insurance-Purchasing-Trends.

[18] Exhibit Staff/702, Bahr/24. Company's response to Staff Data Request No. 248.

[19] Exhibit Staff/702, Bahr/25-26. Company's response to Staff Data Request No. 74.

[20] Confidential Exhibit Staff/703, Bahr/1. Company's Confidential response to Staff Data Request No. 241.

[21] Exhibit Staff/702, Bahr/27-28. Company's response to Staff Data Request No. 127.

[22] Exhibit Staff/702, Bahr/29-30. Commission Order No. 09-020 at 19-20.

of the insurance cost. This adjustment results in reduction to expenses of $56,598.

R&D Costs-

The Company reported that no R&D costs were included in the test year revenue requirement.[23] Staff's review supports this statement, as no R&D related costs were found in the Company's base year non-labor expenses.[24] Accordingly, Staff has no proposed adjustment related to R&D costs.

Training and Education Costs-

The Company's education reimbursement policy specifies that job-related courses are reimbursed 75 percent as non-taxable income to the employee and non-job-related courses are reimbursed as taxable income. The annual limit for tuition reimbursement is $5,250.[25] The Company's training and education expenses for the test year (estimated) and preceding three years are as follows:

Table 5. Oregon Allocated Training & Education Expenses[26]

Year	Expense
2012	$921
2013	$757
2014	$1,996
2015 (estimated)	$4,243

The average of 2012 through 2014 expense amounts is $1,225, and using a trend function to forecast the 2015 test year expense based on the years

[23] Exhibit Staff/702, Bahr/31. Company's response to Staff Data Request No. 126.
[24] Exhibit Staff/704. The Company's 2014 non-labor expenses were reported in response to Staff Data Request No. 57.
[25] Exhibit Staff/702, Bahr/32-38. Company's response to Staff Data Request No. 124.
[26] Exhibit Staff/705. Company's response to Staff Data Request No. 125.

2012 through 2014, Staff obtained a forecast of $2,300. The Company explained the 164 percent increase in training and education expenses between 2013 and 2014 by stating it "…is attributable to reimbursable education expenses…" The 113 percent increase between 2014 and 2015 was explained as being "…based off of the 2014 budget amount of $17,057.98, increased by using an escalation factor of 2.5%."[27]

Based on the analysis described above, Staff proposes reducing the Company's proposed $4,243 training and education expense amount to $2,300, which is the amount Staff forecasted for 2015 by trending the years 2012 through 2014. Staff sees no viable reason to include training and expense amounts in the revenue requirement above Staff's proposal, based on the historical trend of spending by the Company. The amount of the downward expense adjustment is $1,944

<u>Miscellaneous A&G Expenses</u>-

To identify any miscellaneous A&G expenses that appear to not be related to the provision of safe and reliable energy to customers, Staff first created a pivot table of the Company's 2014 A&G non-labor expenses.[28] Staff reviewed each expense explanation and identified those expenses that appeared inappropriate for inclusion in Cascade's revenue requirement. These potentially inappropriate costs were grouped into three categories. The first category contains costs relating to meals, entertainment, prizes, flowers, and

[27] Exhibit/702, Bahr/39. Company's response to Staff Data Request No. 250.
[28] Exhibit Staff/704. The Company's 2014 non-labor expenses were reported in response to Staff Data Request No. 57.

other miscellaneous expenses. The second category contains costs associated with memberships, sponsorships, dues, donations, etc. The third category contains travel expenses, flights, hotels, etc.

Category 1, which includes such line items as "$5 Starbucks Cards," "2014 Flashback Cruz," "5k fun run," and "8 metal seahawk sculptures," was adjusted by 50 percent in accordance with Commission precedent for meals and entertainment.[29] The amount of the adjustment for Category 1 expenses is $638,896.

The second category, containing such expense descriptions as "First Night Festival sponsor," "Leadership Conference," and "NACE membership," was adjusted by the Company in its adjustments from base year to test year. The Company removed 25 percent of membership fees, which resulted in a decrease in 2015 proposed test year revenue requirement of $3,648. However, Staff proposes 100 percent removal of the Company's dues, subscriptions, sponsorships, fees, etc. It is the burden of the Company to demonstrate that any expenses reasonably lead to the provision of safe and reliable services, and Staff believes the Company has not met its burden of proof for any of its proposed test year costs relating to dues and memberships. Staff's adjustment removes from the Company's A&G expenses $635,248.

Staff also proposes an adjustment related to the Company's travel costs, which Staff grouped into Category 3 and include line items such as baggage fees, taxis to airports, parking, and hotels. As it is virtually impossible to

[29] Exhibit Staff/702, Bahr/40. Commission Order No. 09-020 at 21.

determine which specific expenses should and shouldn't be included for recovery from customers, Staff proposes that 50 percent of the projected 2015 expenses be removed. Thus, expenses are better matched between ratepayers and reasonable costs to provide service. Staff's adjustment is a reduction to A&G expenses of $21,585.

The following table shows the amounts identified by Staff in each category that appear inappropriate to be included in rates.

Table 6. Selected Miscellaneous Base Year Expenses

	Oregon Total	Staff Adjustment
Total 2014 Misc Expenses	$4,721,777	
Less Company Adjustment	($3,648)	
	$4,718,129	
Category 1	$266,623	$133,312
Category 2	$638,896	$638,896
Category 3	$43,170	$21,585
Total 2014 Adjustment		$793,793
2015 Escalation Factor[30]		-0.04%
Total 2015 Adjustment[31]		$794,110

Staff's summary table regarding the three A&G adjustments is shown below. Note that the D&O adjustment was based on the Company's proposed 2015 test year estimated cost provided by the Company, the training and education adjustment was based on a 2015 forecast calculated by Staff, and the miscellaneous expense adjustment was based on 2014 actuals, which were escalated to 2015.

Table 7. A&G Adjustment Proposed by Staff (OR allocated)

[30] The Urban Consumers 2015 CPI was used to escalate 2014 expenses, and obtained from the following quarterly report: http://www.oregon.gov/DAS/OEA/docs/economic/appendixa.pdf.
[31] The 2015 adjustment was calculated by escalating the 2014 amount by -0.04 percent.

Adjustment Description	Company Filing	Staff Proposed	Adjustment Amount
D&O	$27,506	$13,753	$13,753
Training & Education	$4,243	$2,300	$1,944
Miscellaneous	$4,718,129	$3,928,302	$794,110
		Total	$809,807

<u>Issue 5, Utility Plant & Capital Additions</u>

Q. Please describe the Company's request associated with plant and capital additions.

A. In addition to the Company's $181 million in plant as of December 31, 2014, the Company proposed a test year capital additions budget of approximately $12 million on an Oregon-allocated basis ($63.6 million total company). Associated with the proposed capital additions is also a property tax expense of approximately $178 thousand.[32]

Q. How are plant and capital additions usually treated by the Commission?

A. Staff typically uses a company's last general rate case as a starting point for the amount of plant approved in rate base and then reviews all capital additions through the present and all proposed capital additions through the end of the test year. Staff's goal in reviewing plant is to ensure that costs associated with capital additions are prudent and reasonable and that rate payers are not paying any costs that aren't directly related to providing service to customers. Because it is not feasible for Staff to physically verify all the plant out in the field, it is important for Staff to understand the capital planning, budgeting, and accounting processes.

Q. How did Staff analyze the Company's requested plant and capital additions?

[32] See Parvinen WP 301-304 (3) tabs "Exh 301 – ROO Summary Sheet" and "2015 Plant Additions."

A. Staff reviewed the Company's responses to 29 Staff data requests related to plant and capital additions as well as the testimony and supporting work papers included in the Company's filing. Additionally, Staff visited Company offices to discuss aspects of the Company's capital budgeting, accounting, field work, and regulatory affairs. Because of the length of time since the Company's last general rate case, Staff was unable to obtain reliable records of all plant additions dating back since the Company's rate base was last approved by the Commission. However, Staff relied upon work performed by Commission Staff outside of general rate cases to confirm the capital balance through December 31, 2014.

Staff also reviewed the general trend of the Company's capital balances to ensure reasonableness. The two tables below show the Company's annual plant in service balances over the past 10 years as well as the monthly balances in the base year, 2014.

Table 8. 2014 Monthly Plant in Service Balances[33]

Dec 2013	$168,307,838
Jan 2014	$173,429,424
Feb 2014	$173,526,790
Mar 2014	$173,760,840
Apr 2014	$174,031,016
May 2014	$174,319,872
Jun 2014	$174,566,735
Jul 2014	$175,190,257
Aug 2014	$175,797,950
Sep 2014	$177,562,143
Oct 2014	$178,134,169
Nov 2014	$178,697,249

[33] Exhibit Staff/702, Bahr/41. Company's response to Staff Data Request No. 138.

Dec 2014	$180,947,303

Table 9. 2005-2014 December 31st Plant in Service Balances[34]

2005	$125,669,644
2006	$134,519,880
2007	$144,495,778
2008	$152,588,416
2009	$154,702,141
2010	$156,411,817
2011	$158,853,770
2012	$164,348,791
2013	$172,709,350
2014	$180,947,303

Staff's review resulted in four adjustments related to Plant and Capital Additions. These are described in detail below.

Q. Please describe Staff's first adjustment related to blanket projects.

A. Using information provided by the Company, Staff carefully reviewed the proposed test year capital additions budget in detail. First, Staff identified all costs associated with work orders labeled as "blanket." The Company explained that "Blanket Funding Projects are annual estimates of spending for projects/items with costs under $100,000 that have been aggregated together into one budgeting bucket called a "Funding Project".[35] The Company's annual total costs for Oregon situs blanket projects and Company projects that are allocated to Oregon are shown in the table below.

Table 10. 2010-2015 Blanket Projects[36]

2010	$1,989,973
2011	$3,062,544
2012	$3,062,454

[34] Exhibit Staff/702, Bahr/42. Company's supplemental response to Staff Data Request No. 137.
[35] Exhibit Staff/702, Bahr/43-44. Company's response to Staff Data Request No. 237.
[36] Exhibit Staff/702, Bahr/45-46. Company's supplemental response to Staff Data Request No. 312.

2013	$4,702,514
2014	$7,195,791
2015 (proposed)	$7,499,680

The amounts in the table above indicate a 262 percent increase from 2010 to 2014, including a 53 percent increase from 2013 to 2014 alone. Though capital projects increased in recent years due to the implementation of Department of Transportation requirements[37] and easy access to capital because of low interest rates, the increase in blanket projects appears excessive.

The three year average (2012-2014) is $4,986,920, which represents approximately 66 percent of the Company's 2015 budget. Staff's proposed adjustment results from applying that 66 percent to the Company's proposed 2015 Oregon situs and allocated blanket costs amount of $4,877,881. Therefore, Staff's proposed rate base adjustment related to blanket projects is $1,634,329.[38]

Q. Please describe Staff's second adjustment relating to in-service dates of capital projects.

A. Again using information provided by the Company, Staff reviewed the proposed in-service date for each non-blanket capital project the Company proposed be included in the test year. Of the 28 projects, Staff identified 15 that no longer appear will be completed by the end of 2015. Though Staff requested the Company provide support for all projects the Company proposed

[37] *See* CNG/100, Madison/3, at line 13, as well as the Company's response to Staff Data Request No. 184, included as Exhibit Staff/702, Bahr/47.
[38] Adjustment calculated as $4,877,881 * (1 – 66.4951%) = $1,634,329.

to include in the test year, none was provided.[39] Of the $7,165,538 of non-blanket projects included in the revenue requirement by the Company, $3,193,357 appears to be associated with projects that are not scheduled to be completed by December 31, 2015, and is the amount of Staff's proposed adjustment to rate base.

Q. Please describe Staff's third adjustment relating to actual costs versus budgeted costs?

A. Of the non-blanket projects scheduled for 2015 completion, Staff selected three with high dollar amounts. Two of the projects are Oregon-allocated and one is Oregon situs. The cumulative cost of the three projects amounts to over 75 percent of the total 2015 capital addition costs. For these three projects, Staff compared the amount spent for each project during the first half of 2015 to the amount budgeted for the entire year.

Table 11. Dollars spent in first half 2015 versus full year budget[40]

Project	2015 full year budget	First half actual $ spent	% Spent of Budget
FP-200688 - BEND PIPE REPL	$2,450,964	$144,652	6%
FP-200352 - CC&B COSTS	$394,320	$986,110	61%
FP-200663 - UG GIS ENHANCEMENTS CNG DIRECT	$162,463	$17,105	3%
Total	$4,742,250	$1,147,867	24%

[39] Exhibits Staff/702, Bahr/48-49 and Bahr/50-51. Company's responses to Staff Data Request Nos. 313 and 315, respectively.
[40] Exhibits Staff/702, Bahr/52-54 and Bahr/48-49. Company's responses to Staff Data Request Nos. 311 and 313, respectively.

From the monthly information for 2014 provided in Table 8 above, it is evident that although capital costs may fluctuate from month to month, almost exactly half of the Company's 2014 costs occurred in the first half of the year, and the other half occurred in the second half.

Table 12. 2014 Capital Additions (first half versus second half)[41]

	Jan-Jun 2014	Jul-Dec 2014
Amount spent	$6,258,897	$6,380,568
% of full year cost	49.5%	50.5%

It is reasonable to assume that 2014 represents a typical year of capital spending for the Company, and that dollars spent on capital projects in 2015 would follow a similar pattern.

Because the Company's spending in the first half of the test year represents only 24 percent of the full year budget, and the 2014 data indicates spending in the first and second half of the year should be similar, Staff suspects the Company has over-estimated its 2015 capital budget. Therefore, Staff estimated the Company's actual full-year cost by extrapolating the amount spent in the first half. Staff then compared this amount to the Company's proposed budget, resulting in an adjustment to rate base of approximately $2 million.

Q. Please describe Staff's fourth adjustment, relating to property taxes.

A. Staff adjusted the property tax expense associated with the Company's proposed capital additions to reflect Staff's three adjustments to rate base. This results in an adjustment to expense of approximately $102 thousand.

[41] Exhibit Staff/702, Bahr/41. Company's response to Staff Data Request No. 138.

Q. Please summarize Staff's adjustments relating to plant and capital additions.

A. Staff reduced the Company's proposed "blanket" project costs based on historical data and trends. Staff also removed all projects not expected to be completed in the test year and reduced the Company's budget to reflect the lower amount of actual costs compared to the budget. Property tax expense was also reduced to reflect Staff's proposed adjustments to rate base. The adjustments are shown in the table below.

Table 13. Staff's proposed capital additions adjustments

Company proposed 2015 capital additions	$12,043,418
Adjustment 1 ("Blanket" Projects)	$1,634,329
Adjustment 2 (In-Service)	$3,192,357
Adjustment 3 (Actual vs Budget)	$2,049,755
Staff proposed 2015 capital additions	$5,166,977
Company proposed property tax expense	$178,375
Adjustment 4 (Property Taxes)	$101,847
Staff proposed property tax expense	$76,528

Summary of Recommendations

Q. Please provide a summary of Staff's recommendations.

A. The table below illustrates the adjustments proposed by Staff.

Table 14. Adjustments proposed by Staff

	Adjustment (000)	Expense or Rate Base
FAS 87 Pension Cost	N/A	N/A
Prepaid Pension Asset (net of deferred taxes)	$2,873	Rate Base
Medical Benefits	$1,060	Expense
Affiliated Interests	N/A	N/A
Miscellaneous A&G	$810	Expense
Plant & Capital Additions	$6,876	Rate Base
Property Taxes	$102	Expense

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 287
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

July 31, 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 287
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

July 31, 2015

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 59

Date prepared: 4/7/2015

Preparer: Mike Parvinen

Contact: Mike Parvinen

Telephone: (509)-734-4593

59. In the following table format, please provide the FAS 87 and FAS 106 Post-retirement Plan information for the Test Year, Base Year, and the three years prior to the Base Year. Please explain any variation between Long-term Rate of Return on Assets, and Actual Rate of Return on Assets.

	Test Year	Base Year	Base Year – 1	Base Year – 2	Base Year – 3
Obligation at December 31					
Fair Value of Plan					
Actual Return on Assets					
Benefits Paid					
Funded Status					
Accumulated Benefit Obligation					
Funded Ratio					
Service Cost					

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Interest Cost					
Expected Return on Assets					
Amortization of Transition Asset					
Amortization of Prior Service Cost					
Recognized (Gain) Loss					
Net Periodic Pension Cost (Income)					
Company's Contribution to Plan					
Discount Rate for Benefit Obligation					
Discount Rate for Annual Expense					
Long-term Rate of Return on Assets					
Actual Rate of Return on Assets					

Response:

The blanks in the charts indicate inability to locate specific information in the Actuarial reports. The actuarial reports (2010 and 2011) are also attached to provide a complete record. Please see response to A82 for copies of actuarial reports for 2012 – 2014.

	Test Year	Base Year	Base Year – 1	Base Year – 2	Base Year – 3
Obligation at December 31			$81,736,849	$91,932,961	$87,103,752
Fair Value of Plan		$67,194,603	$63,514,799	$61,515,517	$53,264,719

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
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Actual Return on Assets					
Benefits Paid					
Funded Status					
Accumulated Benefit Obligation					
Funded Ratio		80%	84.17%	80%	80%
Service Cost		$0	$0	$1,252,349	$1,075,305

Interest Cost		$3,619,743	$3,296,525	$3,506,605	$3,751,943
Expected Return on Assets		$4,292,182	$4,071,689	$4,527,611	$4,001,747
Amortization of Transition Asset					
Amortization of Prior Service Cost		0	0	($155,991)	($155,991)
Recognized (Gain) Loss		41,031,162	$1,403,946	$3,410,842	$2,627,451
Net Periodic Pension Cost (Income)		$358,723	$628,782	$3,486,194	$3,296,961
Company's Contribution to Plan		$2,475,877	$2,185,778	$1,803,754	$3,605,167
Discount Rate for Benefit Obligation		4.56%	3.68%	4.15%	5.25%
Discount Rate for Annual Expense					
Long-term Rate of Return on Assets		7.00%	7.00%	7.75%	7.75%
Actual Rate of Return on Assets					

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 131

Date prepared: 5/11/15

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)734-4591

131. With regard to the Company's response to Staff Data Request No. 59

a. What is the amount of FAS 87 expense included in the test year revenue requirement?
b. Please provide the calculation of the FAS 87 expense included in the test year revenue requirement.
c. Please provide a narrative description explaining how the Company arrived at its test year pension expense forecast.

Response:

a. **$612,000** is the test year total system amount. However, Cascade did not propose a change from the the base year total system amount of $359,000.

b. The calculation of the $612,000 is just an estimate for 2015. Cascade Natural Gas will receive the 2015 actual expense amount by the end of June, which will include the calculation documentation.

c. CNG receives a report identifying our estimated expense to book for the calendar year in January of each year. This report is followed up with by the end of June (as stated in section b.) with the actual expense amount then the books are trued up with the current actnal amount

Please see Confidential A131-Assumptions used for estimate.pdf

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 130

Date prepared: 5/12/2015

Preparer: Michael Parvinen

Contact: Pamela Archer

Telephone: (509)-734-4591

130. Was the Company's prepaid pension asset balance (net of associated accumulated deferred taxes) included in rate base of the Company's last general rate case?

Response:

No.

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			$ 50,276	$ 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	17,882	16,249	17,598	3,521	3,215	4,166
Expected return on assets	(21,218)	(19,917)	(23,536)	(4,817)	(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

Staff/702
Bahr/7

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.

	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

* 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.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 63

Date prepared: 02/17/2015

Preparer: Candice Tschauner

Contact: Pam Archer

Telephone: (509)-734-4591

63. In the following table format, please provide medical benefit costs for the Test Year, Base Year, and the three years prior to the Base Year. Please also explain if the amounts reflected in the Company's response are before or after employer/employee sharing. For the Test Year estimates, please explain the assumptions relied upon (i.e. increased employees, specific escalation factor to premiums, etc.) in arriving at the forecasted amounts.

	Test Year	Base Year	Base Year – 1	Base Year – 2	Base Year – 3
Medical					
Dental					
401(k)					
Group Life Insurance					
Retiree Life Insurance					
Long-Term Disability					
Other (*Please Label*)					
Total					

Response:

Please see spreadsheet A63.xlsx.

CNG OPUC DR 63

	Escalation Factor	2015	2014	2013	2012	2011
5192 Other Benefits	1.025	38,528.02	187,158.19	37,588.31	54,975.05	48,139.54
5194 Medical/Dental & Life Insurance	1.06	2,971,975.29	2,808,428.22	2,276,096.20	2,207,277.56	2,004,772.45
5195 Pension	0.5272	307,139.81	287,890.21	515,732.40	569,156.02	2,534,799.12
5196 Post Retirement	0.8416	410,230.88	91,575.46	471,328.05	363,617.11	(927,072.35)
5197 401-K Plan	1.025	2,145,172.87	2,254,741.48	2,025,412.23	1,045,523.70	878,820.32
5199 Workers Compensation	1.025	239,148.96	228,012.89	280,677.55	267,186.11	242,374.10
5921 Supplemental Defined Plan & Contributi	1.025	514,162.85	444,772.38	(444,679.89)	79,052.96	1,044,465.03
		$6,626,358.68	**$6,302,578.83**	**$5,162,154.85**	**$4,586,788.51**	**$5,826,298.21**

Explanations

1.) Amounts reflected are after employer/employee sharing.

2.) Assumptions for test year estimate are used with specific escalation factors applied to 2014 Budget to arrive at forecasted amounts.

3.) Assumptions for test year estimate for 5192 Other Beneftis are used with specific escalation factor applied to 2013 acutals. Cascade does not budget for Other Benefits, and there was an unusual high cost in 2014.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 64

Date prepared: 3/30/15

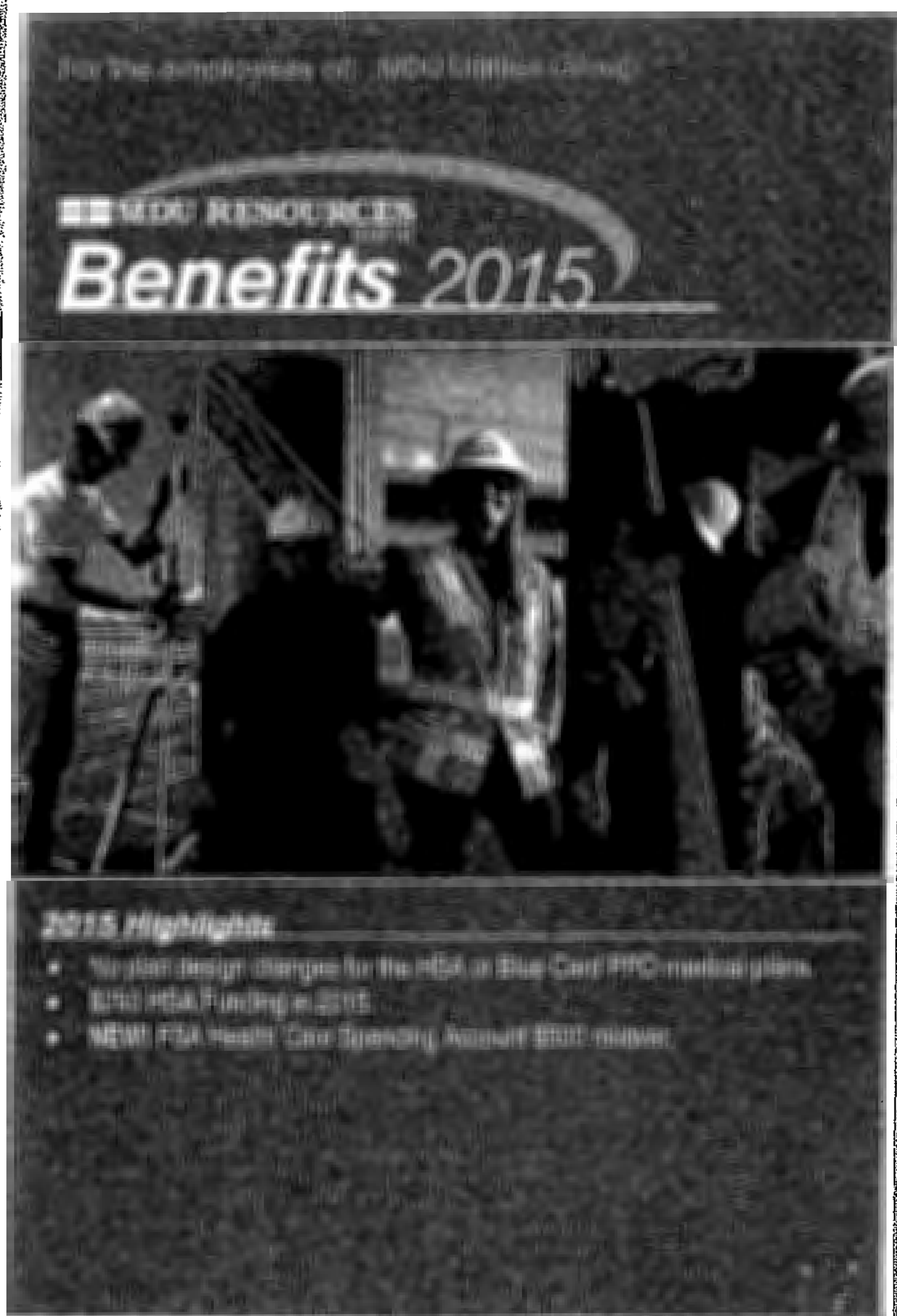
Preparer: Bob Harris

Contact: Pam Archer

Telephone: (509)-734-4591

64. For each Medical (Health, Dental, and Vision) plan, please identify the premium for the Test Year, Base Year, and two calendar years prior to the Base Year. If the premium amounts vary by labor group, please provide the information for each labor group separately.

Response: Attached are monthly Employee/Employer premiums for years 2015, 2014 & 2013 Premium amounts do not vary between groups.



Enrollment Open November 10-28, 2014

Enroll at eserve.mdu.com

Medical Benefits

Health Savings Plan and Account (HSA)

The HSA Plan is a high-deductible plan that allows employees to establish a separate account to make pretax deferrals up to IRS limits of $3,350 (single) or $6,650 (family). If you are 55 or older, you can contribute an additional $1,000. To contribute:

- You must elect a 2015 HSA contribution level; prior year elections do not carry over.
- You may not be covered under any non-high deductible health plan, including your spouse's flexible spending account or any part of Medicare.
- New HSA participants will receive a *Welcome Kit*, including account contract terms and debit card, by January 10, 2015.

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$4.15	$347
Employee + Child	$6.92	$589
Employee + Children	$9.69	$726
Employee + Spouse	$20.31	$774
Family	$33.23	$1,046

BlueCard PPO Plan

The BlueCard PPO plan provides comprehensive coverage with a copay, deductible, and co-insurance structure.

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$36.46	$364
Employee + Child	$63.23	$617
Employee + Children	$78.46	$761
Employee + Spouse	$94.15	$816
Family	$128.31	$1,116

Opt-Out Feature

- If you elect to opt-out of the Company's medical insurance due to other available coverage, $100/month (taxable) will be included in your first paycheck each month.
- If you, your spouse, or your dependents are employees of the Company, the Opt-Out Feature is not available if anyone is covered by the Company medical plan.

Premiums are based on the total expected cost of the self-insured plans covered under the MDU Resources Group, Inc. Health and Welfare Benefit Program. The Company's practice is to share premium increases with the employee; however, the maximum aggregate medical increase to the employer contribution will not exceed 6% annually.

Dental Benefits

The Company offers a choice of three dental plans. These dental plans provide first-dollar coverage for routine oral examinations, cleanings, and certain X-rays, along with coverage for other services after meeting a deductible. The Dental with Orthodontia plan provides $1,500 lifetime maximum orthodontia benefit for children under age 19. These plans access the Delta Dental provider network.

The two-year dental lock-in provision requires employees to maintain elected coverage for at least two years. Upgrades are allowed at open enrollment or at the time of a qualifying event, but restart the two-year lock-in requirement.

Dental Maintenance Plan

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$2.61	$16
Employee + 1	$4.15	$29
Family	$7.35	$50

Dental

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$6.46	$21
Employee + 1	$10.62	$41
Family	$16.46	$73

Dental with Orthodontia

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$10.62	$21
Employee + 1	$19.85	$39
Family	$35.08	$68

Vision Benefits

The vision plan provides coverage for an exam, lenses and frames, with applicable copays and allowance maximums. The plan accesses the VSP provider network.

Coverage	Employee Contribution (per pay period)	Company Contribution (per pay period)
Employee	$4.62	$0
Employee + 1	$6.00	$0
Family	$10.15	$0

Other Benefits

Flexible Spending Account (FSA)

The FSA allows you to defer up to $2,500 to a Health Care Spending Account to use for eligible health care expenses, and/or up to $5,000 per household to a Dependent Care Spending Account for eligible dependent care expenses incurred while you are at work.

- **NEW!** Any unused Health Care Spending Account funds from the current plan year account – up to $500 – will automatically rollover for use in the following plan year (no action is required). Any funds over $500 will be forfeited. The rollover amount does not count toward or reduce the annual $2,500 contribution maximum. Even if an election for the new plan year is not made, remaining funds will be carried over into the new plan year.
- If enrolled in the HSA Plan, the FSA Health Care Spending Account reimbursements are limited to dental and vision expenses until the HSA Plan deductible has been reached.
- When you elect the FSA Health Care Spending Account, you are enrolled in Crossover (automatic claims submission for payment). If you have dual coverage, an Opt-Out form should be completed to avoid duplicate payment. If you are covered under the HSA Plan, you are not able to have an HSA debit card and be enrolled in Crossover.

2014 MONTHLY PREMIUMS

MDU Utilities Group

Medical, Dental, and Vision

	Employee Contribution Monthly	Employee Contribution Pay Period (26)	Company Contribution Monthly	Full Premium Monthly
Health Savings Account (HSA) Plan				
Employee	$8	$3.69	$330	$338
Employee + Child	$15	$6.92	$594	$609
Employee + Children	$19	$8.77	$691	$710
Employee + Spouse	$35	$16.15	$736	$771
Family	$67	$30.92	$995	$1,062
BlueCard PPO				
Employee	$76	$35.08	$346	$422
Employee + Child	$137	$63.23	$622	$759
Employee + Children	$162	$74.77	$724	$886
Employee + Spouse	$191	$88.15	$770	$961
Family	$264	$121.85	$1,060	$1,324
Dental Maintenance Plan				
Employee	$5	$2.31	$16	$21
Employee + 1	$9	$4.15	$29	$38
Family	$17	$7.85	$50	$67
Dental				
Employee	$14	$6.46	$21	$35
Employee + 1	$23	$10.62	$41	$64
Family	$40	$18.46	$73	$113
Dental with Orthodontia				
Employee	$23	$10.62	$21	$44
Employee + 1	$43	$19.85	$39	$82
Family	$76	$35.08	$68	$144
Vision				
Employee	$10	$4.62	$0	$10
Employee + 1	$13	$6.00	$0	$13
Family	$22	$10.15	$0	$22

The premiums above are based on the total expected cost of the self-insured plans covered under the MDU Resources Group, Inc. Health and Welfare Benefit Program. The Company's practice is to share premium increases with the employee; however, the maximum aggregate medical increase to the employer contribution will not exceed 6% annually.

Life Insurance

Age As of January 1, 2014	Life Insurance Monthly Rate per $1,000 of Coverage	Life Insurance Pay Period Rate per $1,000 of Coverage
	Employee/Spouse:	
Under 30	$0.08	$0.037
30-34	$0.09	$0.042
35-39	$0.12	$0.055
40-44	$0.17	$0.078
45-49	$0.30	$0.138
50-54	$0.46	$0.212
55-59	$0.77	$0.355
60-64	$1.00	$0.462
65-69	$1.96	$0.905
70+	$3.25	$1.500
	Child(ren):	
	$ 5,000 $.30	
	$10,000 $.60	

Voluntary AD&D Insurance

Coverage Amount	Monthly Premium	Pay Period Premium
$25,000	$0.63	$0.291
$50,000	$1.25	$0.577
$100,000	$2.50	$1.154
$150,000	$3.75	$1.731
$200,000	$5.00	$2.308

MDU Resources Group, Inc. expects to continue these benefit plans indefinitely; however, it reserves the right to amend or terminate these plans at any time for any reason to comply with any federal or state laws governing welfare benefits, the requirements of the Internal Revenue Code or ERISA.

2013 PREMIUMS
MDU UTILITIES GROUP

Medical, Dental, and Vision	Monthly Employee Contribution	Pay Period (26) Company Contribution	Monthly Company Contribution	Monthly Full Premium
Health Savings Account (HSA) Plan				
Employee	$8	$3.69	$316	$324
Employee + Child	$14	$6.46	$569	$583
Employee + Children	$18	$8.31	$662	$680
Employee + Spouse	$33	$15.23	$705	$738
Employee + Spouse + Child(ren)	$63	$29.08	$954	$1,017
BlueCard PPO				
Employee	$73	$33.69	$331	$404
Employee + Child	$132	$60.92	$596	$728
Employee + Children	$156	$72.00	$693	$849
Employee + Spouse	$184	$84.92	$738	$922
Employee + Spouse + Child(ren)	$260	$120.00	$1,010	$1,270
Dental Maintenance Plan				
Employee	$5	$2.31	$16	$21
Employee + 1	$9	$4.15	$29	$38
Family	$17	$7.85	$50	$67
Dental Basic Plan				
Employee	$14	$6.46	$21	$35
Employee + 1	$23	$10.62	$41	$64
Family	$40	$18.46	$73	$113
Dental with Orthodontia				
Employee	$23	$10.62	$21	$44
Employee + 1	$43	$19.85	$39	$82
Family	$76	$35.08	$68	$144
Vision				
Employee	$10	$4.62	$0	$10
Employee + 1	$13	$6.00	$0	$13
Family	$22	$10.15	$0	$22

The premiums above are based on the total expected cost of the self-insured medical plans covered under the MDU Resources Group, Inc. Health and Welfare Benefit Program. The Company's practice is to share premium increases with the employee; however, the maximum aggregate increase to the employer contribution will not exceed 6% annually.

Life Insurance

Age As of January 1, 2013	Employee/Spouse: Monthly Rate per $1,000 of Coverage	Employee/Spouse: Pay Period Rate (26)	Child(ren): Coverage Amount	Child(ren): Monthly Rate	Child(ren): Pay Period Rate (26)
Under 30	$0.08	$0.037	$5,000	$0.30	$0.139
30-34	$0.09	$0.042	$10,000	$0.60	$0.277
35-39	$0.12	$0.055			
40-44	$0.17	$0.079			
45-49	$0.30	$0.139			
50-54	$0.46	$0.212			
55-59	$0.77	$0.355			
60-64	$1.00	$0.462			

Lower Employee Coverage Cost

Voluntary AD&D Insurance

Coverage Amount	Monthly Premium Amount	Pay Period (26) Premium Amount
$25,000	$0.63	$0.291
$50,000	$1.25	$0.577
$100,000	$2.50	$1.154
$150,000	$3.75	$1.731
$200,000	$5.00	$2.308

MDU Resources Group, Inc. expects to continue these benefit plans indefinitely; however, it reserves the right to amend or terminate these plans at any time for any reason to comply with any federal or state laws governing welfare benefits, the requirements of the Internal Revenue Code, or ERISA.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 253

Date prepared: June 19, 2015

Preparer: Becky Mellinger

Contact: Pamela Archer

Telephone: (509)734-4591

253. Please provide annual budgeted costs for 2011 through 2015, in the same format as the Company's response to Staff Data Request No. 63.

Response:

		Escalation Factor	2015 Preliminary Budget	2014	2013	2012	2011
5192	Other Benefits	1.025	18,486.60	18,035.71	37,786.58	15,101.08	14,343.54
5194	Medical/Dental & Life Insurance	1.06	2,971,975.29	2,803,750.27	2,500,463.13	2,448,066.68	2,300,296.38
5195	Pension	0.5272	307,139.81	582,586.89	1,016,213.02	2,145,575.07	1,552,138.83
5196	Post Retirement	0.8416	410,230.88	487,441.64	716,714.95	391,688.73	(575,899.02)
5197	401-K Plan	1.025	2,145,172.87	2,092,851.58	2,235,312.37	1,260,121.42	1,110,638.22
5199	Workers Compensation	1.025	239,148.96	233,316.06	214,951.87	150,295.83	182,125.47
5921	Supplimental Defined Plan & Contribut	1.025	514,162.85	501,622.29	534,092.89	598,322.48	579,509.17
			$ 6,606,317.26	$ 6,719,604.44	$ 7,255,534.81	$ 7,009,171.28	$ 5,163,152.59

2015 Budget amounts for DR 63 & DR 253 are preliminary 2015 budget data derived from 2014 Budget amount multiplied by an escalation factor.

Staff/702
Bahr/22

Employer Health Benefits

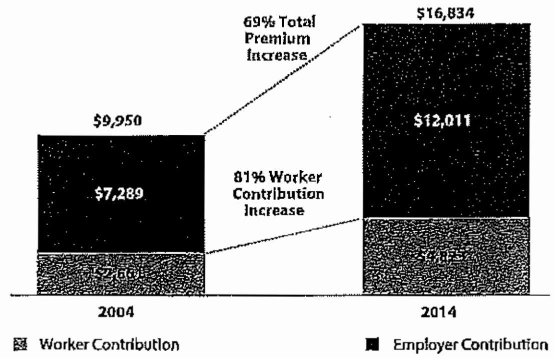
2014 Summary of Findings

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

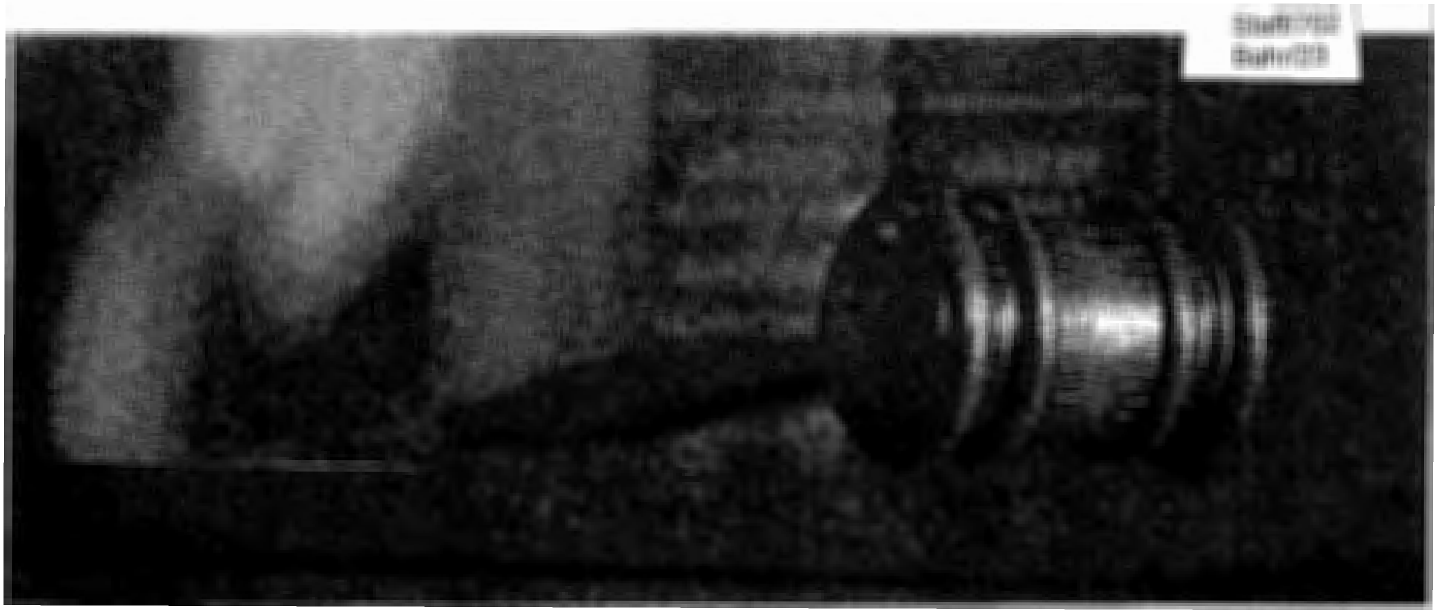
In 2014, the average annual premiums for employer-sponsored health insurance are $6,025 for single coverage and $16,834 for family coverage. The average family premium rose 3% over the 2013 average premium. Single coverage premiums rose 2% in 2014 but are not statistically different than the 2013 average 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).

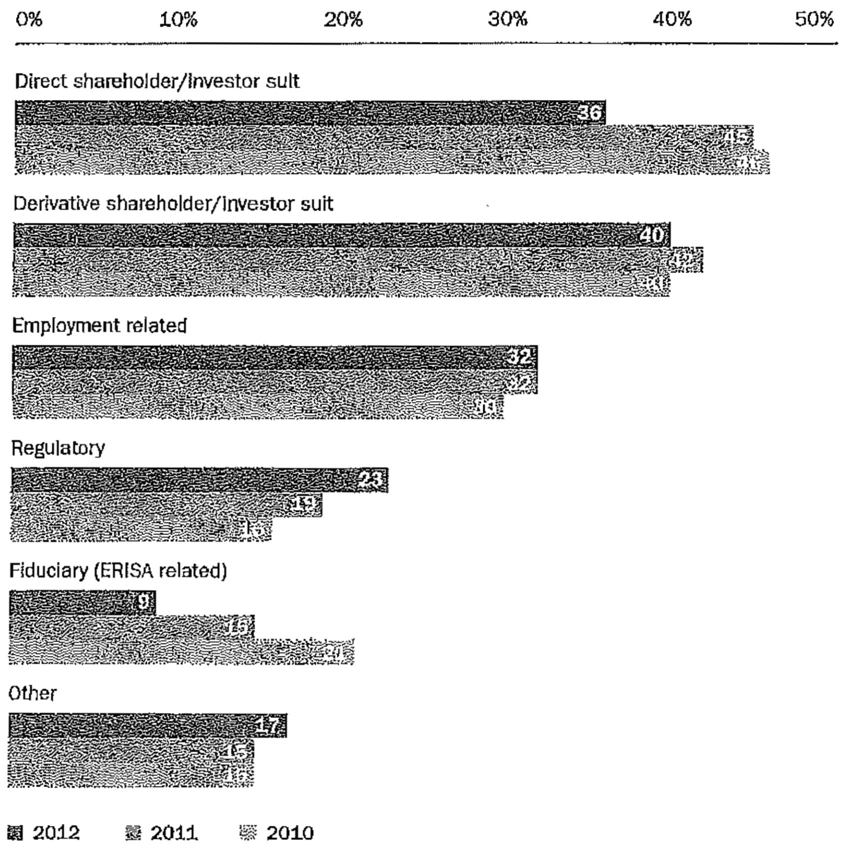
Most often, employers require that workers make a contribution towards the cost of the premium. Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2013. Workers in small firms (3–199 workers) contribute a lower 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



actions, increasing to 23% of responses from 19% in 2011 and 16% in 2010 *(Figure 34)*. Consistent with our last three reports, derivative shareholder/investor suits and direct shareholder/investor suits continue to lead the types of claims filed over the last 10 years. Direct shareholder suits have trended downward, with derivative shareholder suits remaining relatively constant over the same period (Figure 34).

Figure 34. Types of claims in the last 10 years



CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 248

Date prepared: June 19, 2015

Preparer: Vicki Kunz

Contact: Pamela Archer

Telephone: (509)-734-4591

248. With regard to the Company's response to Staff Data Requests Nos. 74 and 191, please identify any legal cases brought against directors or officers of the Company in the last 10 years and provide a brief description of each, including the result.

Response:

There have been no D&O legal actions against Cascade since purchased in July 2, 2007.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 74

Date prepared: 4/7/2015

Preparer: Jonathan Fleischer

Contact: Pam Archer

Telephone: (509)-734-4591

74. Regarding Director's and Officer Liability Insurance, please fill in the table below:

Insurance	2012 Base Yr -2 Yrs	2013 Base Yr -1 Yr	2014 Base Year	2015 Test Year
D & O Liability Premium				
D & O Liability Deductible				
First Excess D & O Premium				
First Excess D & O Deductible				
Second Excess D & O Premium				
Second Excess D & O Deductible				
Third Excess D & O Premium				
Third Excess D & O Deductible				
4th Excess D&O – Side A DIC Premium				
4th Excess D&O – Side A DIC Deductible				
Total Premium (primary, and all excess)				

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Response:

Insurance	2012 Base Yr -2 Yrs	2013 Base Yr -1 Yr	2014 Base Year	2015 Test Year
D & O Liability Premium	$46,157	$43,746	$46,030	$56,361
D & O Liability Deductible	$1,000,000	$1,000,000	$1,000,000	$1,000,000
First Excess D & O Premium	$39,616	$37,632	$31,286	$35,889
First Excess D & O Deductible	None	None	None	None
Second Excess D & O Premium	$9,344	$9,054	$7,343	$8,249
Second Excess D & O Deductible	None	None	None	None
Third Excess D & O Premium	$4,399	$4,262	$3,457	$3,883
Third Excess D & O Deductible	None	None	None	None
4th Excess D&O – Side A DIC Premium	$10,183	$9,673	$7,846	$8,813
4th Excess D&O – Side A DIC Deductible	None	None	None	None
Total Premium (primary, and all excess)	$109,699	$104,367	$95,962	$113,195

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 127

Date prepared: 5/1/2015

Preparer: Jonathan Fleischer

Contact: Pam Archer

Telephone: (509)734-4591

127. Please fill in the table below:

Insurance	2012 Base Yr -2 Yrs	2013 Base Yr -1 Yr	2014 Base Year	2015 Test Year
D & O Liability Premium	$46,157	$43,746	$46,030	$56,361
D & O Liability Deductible	$1,000,000	$1,000,000	$1,000,000	$1,000,000
First Excess D & O Premium	$39,616	$37,632	$31,286	$35,889
First Excess D & O Deductible	None	None	None	None
Second Excess D & O Premium	$9,344	$9,054	$7,343	$8,249
Second Excess D & O Deductible	None	None	None	None
Third Excess D & O Premium	$4,399	$4,262	$3,457	$3,883
Third Excess D & O Deductible	None	None	None	None

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

4th Excess D&O – Side A DIC Premium	$10,183	$9,673	$7,846	$8,813
4th Excess D&O – Side A DIC Deductible	None	None	None	None
Total Premium (primary, and all excess)	$109,699	$104,367	$95,962	$113,195

Response:

*Yearly budget information is not available for specific policies, as CNG budgets for entire company insurance policies in lump sum.

**2016 premium information is not presently available. Additionally, corporate allocation figures are not available for 2016, therefore any data that may be available, will not have accurate allocation factor for Cascade's cost.

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.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 126

Date prepared: 5/1/2015

Preparer: Chris Ryan

Contact: Pamela Archer

Telephone: (509)734-4591

126. Please provide the annual amount, for each year, the Company spent on research and development in 2012 through 2014, inclusive, the amount allocated to the Company for research and development in those years, inclusive, and also provide the amount included in the test year revenue requirement.

Response: None to report.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 124

Date prepared: 5/1/2015

Preparer: Chris Ryan

Contact: Pamela Archer

Telephone: (509)734-4591

124. Please provide a copy of the Company's current education reimbursement policy. If any costs for education are allocated to the Company for education reimbursement, please provide the education policy of the company employing the person receiving the training.

Response: See attached file A124 Policy.pdf

TRAINING AND EDUCATIONAL ASSISTANCE

I. PURPOSE

To identify the circumstances when training and education assistance is provided to employees. Tuition will be reimbursed to eligible employees who meet all of the requirements of this policy and follow all of the procedures set forth below.

II. SCOPE

A. To establish a policy and guidelines for the development, training and education of the Company's employees, as required by Corporate Policy Statement CORP 140.4. "Employees" as used in this policy means those persons eligible for consideration based on coverage as defined and outlined in Policy HR-1025 entitled "Benefit Eligibility."

B. This policy applies to all regular full-time employees. Tuition reimbursement requires twelve (12) months of continuous service. Employees may not apply for tuition reimbursement until the full twelve (12) months of continuous service have been completed.

C. Continued eligibility and reimbursement is contingent upon full-time employment and continued good performance, conduct, and attendance.

D. A written career plan and career discussion with the appropriate manager and a Human Resource Representative must be completed in order for college degree/certificate completion tuition reimbursement to be considered for approval.

E. Tuition reimbursement is available for courses offered by fully accredited colleges, universities, trade or technical schools. This includes face-to-face, online, independent-study, self-study, and correspondence courses.

F. Tuition for non job-related courses but required to complete a degree or certificate program that is related to employment may be reimbursable under this policy provided the appropriate approvals are obtained.

G. The company encourages employees to seek funding opportunities through grants, awards, scholarships and other financial support that will offset any reimbursable amount.

H. College Degree or certificate program completion must prepare the employee for more advanced/other positions within the Company as identified in the employee's career plan.

I. Career planning and development is the responsibility of each individual in order to maintain or attain skills and develop competencies necessary to be successful in their current or future job. Employees are encouraged and expected to manage their careers and seek out career opportunities. Financial assistance for developmental opportunities may vary based on business needs, industry practice, and budgetary limitations.

J. In some cases, tuition reimbursement may be used to assist with recruitment efforts as deemed necessary by the company, subject to appropriate taxable provisions.

III. POLICY

A. To qualify for tuition reimbursement the employee must be an active employee at the time payment is being requested. If the employee resigns or is terminated prior to successful completion of a course, no reimbursement will be made and the employee will be required to refund the amount of tuition reimbursement received within the past twelve (12) months of employment. Monies not repaid to the Company will be deducted from the employee's final paycheck to the extent allowable by law. The Repayment of Tuition Reimbursement, form no. 20002, must be completed when applying for Tuition Reimbursement.

B. Employees must receive grades of C or higher for undergraduate courses and courses at technical or trade schools. If a course is offered only as "pass-fail" a passing grade must be obtained. If an employee has the option of choosing to be graded under either a "pass-fail" or a letter grade system, the letter grade system must be used. If no grades are given, the employee must provide proof of successful completion of the course.

C. Individual study and other course work should be done outside of the employee's regular work schedule.

D. It is the employee's responsibility to obtain approval if the training or education requires time away from work and/or financial support before committing to participate.

E. Job-related courses paid for by the employer are not taxable to the employee (26 C.F.R. Sec. 1.162-5.) Courses not meeting the "job-related" test, but reimbursed by the Company, are included as wages in the employee's Form W-2 and will be subject to applicable federal and state withholding provisions. The Company is not responsible for employee's determination of reportable income to the IRS.

F. It is the employee's responsibility to request reimbursement in the year the course was approved. The Company may refuse to reimburse if requests are not timely.

G. Exceptions to the policy must be approved by the CEO and President.

IV. PROCEDURE

A. *Definition* - The Company recognizes several different types of continuing education. All must be evaluated on a course-by-course basis to determine whether they are job-related or not. Tuition reimbursement is limited to $5250 (IRS limit) each calendar year for any job-related and non-job related courses. The following definitions are applied:

   1. Job-related courses are reimbursed at 75% of the cost up to the annual limit (see *Definition*) IRS limitation, as non-taxable income to the employee provided a passing grade as defined in Section III.B. This includes tuition, lab fees, books and other designated fees. All other grades will not be reimbursed. Job-related courses, per the IRS definition, include those:

      a) which maintain or improve the skills required by individuals in their employment; or

b) which meet requirements imposed as a condition of job retention (e.g. continuing professional education requirements imposed by state or professional licensing or regulatory bodies).

2. Non job-related courses will be reimbursed at 75% of the cost up to the annual limit (see *Definition*), as taxable income to the employee, provided a passing grade as defined in Section III.B. This includes tuition, lab fees, books and other designated fees. Reimbursement will be considered wages subject to applicable federal and state withholding provisions. All other grades will not be reimbursed. Non job-related, per the IRS definition, include:

   a) courses that are required to meet minimum educational requirements for employment; or
   b) courses that will qualify the individual for a different position or job.

B. Types of training and education:

1. Home Study Courses - A Home Study Course list is available on the Company's Intranet providing a wide range of subjects from technical skills to human relation skills. Courses range in length from several weeks to four years. If the course is not completed in a timely manner, or employment is terminated, the cost of the course will be withheld from the employee's paycheck.

2. Apprenticeship - Where applicable, the Company and Collective Bargaining Unit collaborate on Department of Labor approved apprentice programs via Joint Apprenticeship and Training Committees in the power production area and region operations. This on-the-job training is considered job-related.

3. External Seminars, Training and Conferences - External learning opportunities include symposiums, conferences, industry related meetings, training workshops, technical training, or vendor sponsored training and may be approved as identified in the employee's career plan to advance their career, prepare for other positions and/or deemed necessary to maintain skills for proficiency in their current job.

4. Educational Courses – As part of an undergraduate degree program, credited courses will be evaluated on a course-by-course basis. Colleges must be listed with the "Higher Learning Commission" for colleges, universities, and degree-granting institutions of higher education.

5. Professional Certificates - Examples of these types of certifications may include Professional Engineer (PE), Certified Public Accountant (CPA), Certified Internal Auditor (CIA), Human Resources certificates (SPHR, PHR), and Information Technology certificates. The costs of such certificates are eligible for reimbursement provided the employee's manager supports and approves the pursuit of such certificates. Payment is conditioned on the certificate being job related, proof of successful completion or passing of the entire certification and the employee's manager's approval. Travel to the test site closest to the community in which the employee resides or the most economical and practical for the Company and

study material that are included in a seminar fee are eligible for reimbursement if approved by the employee's manager.

C. Approval Process - An application for training and education must be approved prior to registration, travel arrangements, and attendance if reimbursement by the Company is expected. The following steps must be taken for all educational courses, conferences, seminars, certifications, etc.:

1. Educational courses are reimbursed from the Human Resources Department budget; all other conferences, seminars, courses, certificates, etc. are reimbursed or paid out of the department budget of the employee.

2. The Application for Training or Educational Assistance (Form 20326) must be completed, submitted for approval and approved prior to the start of the event.

3. The application must always be approved by the immediate supervisor and an Officer. For Executive Development, a level two approval is necessary.

4. The Human Resources Department then approves all applications to ensure a uniform, consistent policy is in place and to ensure appropriate training records are maintained. A copy will be returned to the employee when all approvals have been obtained and the employee is thereby authorized to attend.

5. In the case of external seminars, conferences or other training, payment for registration fees, etc. may be made prior to attending the session, and the remaining costs submitted in accordance with normal expense reimbursement policy.

6. Department of Labor approved apprentices will be automatically enrolled in the appropriate program when they enter their new jobs through the hiring or bidding process. The Human Resources Department will review all forms to ensure appropriate training records are maintained.

7. After completion of the course, the employee must submit a Payment Request, Form 20693, if course is job-related, or the Tuition Reimbursement Request, Form 20285, if course is not job-related. A copy of an invoice or proof of payment, the grade report, and a copy of the approved application form must be attached. Requests for reimbursement must be approved by the employee's supervisor and the Human Resources Department.

V. ADMINISTRATION

The President and Chief Executive Officer (CEO) is responsible for establishing this policy. Administration of the policy is the responsibility of the Director of Human Resources. Requiring compliance with this policy is the responsibility of all officers, directors, managers and supervisors (management). It is also the responsibility of management to ensure that policies are accessible and understood by all employees.

The Company reserves the right to deny any Application for Training or Education assistance for courses, seminars, conferences and programs.

The Company reserves the right to modify or cancel its tuition reimbursement program at any time, with our without notice to employees.

REVIEWED:	[signature]	12/7/12	APPROVED:	[signature]	12/7/12
	DIRECTOR OF HUMAN RESOURCES	DATE		PRESIDENT & CEO	DATE

Repayment of Tuition Reimbursement Agreement

I, ______________________________, understand that if my employment with Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, or Intermountain Gas Company (the Company) ends within one-year following the completion of this course/program, I must pay the amount of the tuition benefit received back to the Company. By signing this agreement, I am authorizing the Company to deduct monies received for tuition reimbursement for the twelve (12)-month period prior to my termination date.

Termination Date: ____________________

Course Name: ____

Employee Signature: ______________________________ **Date:** ______________

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 250

Date prepared: 6/15/15

Preparer: Chris Ryan

Contact: Pam Archer

Telephone: (509) 734-4591

A250. With regard to the Company's response to Staff Data Request No. 125, please provide a narrative description and any supporting documentation explaining the 164 percent increase in Education and Training Expenses between 2013 and 2014 and the 113 percent increase from 2014 to 2015.

Response:

The 164 percent increase between 2013 and 2014 is attributable to an increase in reimbursable Education expenses (mainly the attached Education expense reimbursement for E. Martuscelli) per the attached Policy HR-1060.2

The 113 percent increase from 2014 to 2015, is based off of the 2014 budget amount of $17,057.98, increased by nsing an escalation factor of 2.5%.

See attached PDF file A250_Education Reimbursement Policy.pdf
See attached PDF file A250_E Martuscelli Reimbursement.pdf

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.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 138

Date prepared: 5/12/2015

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)734-4591

138. Please provide monthly plant balances for December 2013 through the present and note whether balances are as of month end or based on monthly average.

Response:

December 2013	168,307,838	Average of averages
January 2014	173,429,424	Balance as of month end
February 2014	173,526,790	Balance as of month end
March 2014	173,760,840	Balance as of month end
April 2014	174,031,016	Balance as of month end
May 2014	174,319,872	Balance as of month end
June 2014	174,566,735	Balance as of month end
July 2014	175,190,257	Balance as of month end
August 2014	175,797,950	Balance as of month end
September 2014	177,562,143	Balance as of month end
October 2014	178,134,169	Balance as of month end
November 2014	178,697,249	Balance as of month end
December 2014	180,947,303	Balance as of month end

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 137

Date prepared: 5/12/2015

Preparer: Kevin Conwell

Contact: Pamela Archer

Telephone: (509)734-4591

137. With regard to Parvinen Exhibit 301, please provide annual plant balances since 2005 through 2014 and note whether balances are as of December 31 or based on each year's annual average.

Response:

Oregon plant in service balances		
2005	125,669,644	Balance as of 12/31/2005
2006	134,519,880	Balance as of 12/31/2006
2007	144,495,778	Balance as of 12/31/2007
2008	152,588,416	Balance as of 12/31/2008
2009	154,702,141	Balance as of 12/31/2009
2010	156,411,817	Balance as of 12/31/2010
2011	158,853,770	Balance as of 12/31/2011
2012	164,348,791	Balance as of 12/31/2012
2013	172,709,350	Balance as of 12/31/2013
2014	180,947,303	Balance as of 12/31/2014

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 237

Date Due to Regulatory: **June 9, 2015**

Date prepared: 6/10/2015

Preparer: Becky Mellinger/Scott Wanner

Contact: Pamela Archer

Telephone: (509)734-4591

237. With regard to the Company's response to Staff Data Request No. 135, please provide the most recent project status reports for each 2015 capital project.

Response:

See Excel spreadsheet A233-238.xlsx

DR 237 Current Project status reports for each 2015 Capital Project as referenced in DR135

Row Labels	2015 Approved Budget	Status (Continuous)
OR		
FP-101170 - MAIN-GROWTH-OREGON	489,544	Blanket
FP-101171 - MAIN-REINFORCE-OREGON	122,853	Blanket
FP-101172 - MAIN-RELO-REPL-OREGON	339,192	Blanket
FP-101173 - R STA-GROWTH-OREGON	108,253	Blanket
FP-101175 - R STA-RELO-REPL-OREGON	122,687	Blanket
FP-101176 - SERV-GROWTH-OREGON	1,146,321	Blanket
FP-101180 - IND M&R-GROWTH-OREGON	98,197	Blanket
FP-101181 - IND M&R-REMOVE&REPLACE-OREGON	49,315	Blanket
FP-101184 - GP TRAN. VEHICLE - OREGON	709,846	Blanket
FP-101186 - GP POWER EQUIP - OREGON	287,968	Blanket
FP-101218 - GP TOOLS - BEND	49,763	Blanket
FP-101234 - GP BUILDINGS - PENDLETON	38,945	Blanket
FP-101237 - GP TOOLS - PENDLETON	17,309	Blanket
FP-101255 - GP TOOLS - ONTARIO	29,533	Blanket
FP-200282 - R STA - SUN RIVER GATE UPGRADE	2,317,813	In Process-Design
FP-200688 - BEND PIPE REPL	2,450,964	In Process-Bidding
FP-200689 - RPL 12" BEND HP LINE #1	1,551	Moved to later budget year
FP-302000 - Baker City Office Purchase	43,272	In Process-Final Work
FP-302370 - GB - GROUNDBED OREGON	426,546	Blanket
FP-302650 - O-4 UMATILLA	206,223	In Process-Design
FP-302651 - O-6 ATHENA	211,111	In Process-Design
FP-302656 - PENDLETON R-9 REPLACEMENT	208,138	In Process-Design
FP-302714 - PENDLETON V-23 REPLACEMENT	67,109	In Process-Design
FP-307026 - ONTARIO 6" IP REPLACEMENT	303,175	Complete
FP-309300 - REPLACE O-3 HERMISTON	174,005	In Process-Design & Procurement
Allocated		
FP-101164 - GP COMM EQUIP - INTERSTATE	357,619	Blanket
FP-101209 - INTANGIBLES - SOFTWARE	129,262	Blanket
FP-101210 - PRE-CAP MTR-GROWTH-INTERSTAT	1,760,984	Blanket
FP-101215 - GP TRAN. VEHICLE - INTERSTAT	145,675	Blanket
FP-101216 - GP TOOLS - INTERSTATE	202,146	Blanket
FP-101259 - PRE-CAP REG-GROWTH-INTERSTAT	263,204	Blanket
FP-101472 - UG-INSTALL WORK MGT-GLE	325,338	In Process
FP-101478 - AUTOMATED VEHICLE LOCATION SYS	112,007	Moved to later budget year
FP-101479 - UG MWM PROJECT - CNGC SHARE	195,808	In Process
FP-101481 - UG GPSLS PROJECT - SOFTWARE	28,923	Delayed; projected 2016 Start
FP-101510 - UG GMS PURCHASE SOFTWARE	110,086	In Process (late June 2015)
FP-200064 - IVR-WEB IMPLEMENTATIION - DRCT	257,382	In Process; estimate complete late Fall
FP-200155 - UG GPSLS PROJECT - HARDWARE	332	Minimal
FP-200352 - CC&B COSTS	1,622,715	In Process
FP-200661 - DATA CENTER/NETWORKING EQUIP	96,065	Blanket
FP-200662 - PC SUPPORT EQUIPMENT	508,451	Blanket
FP-200663 - UG GIS ENHANCEMENTS CNG DIRECT	668,571	In Process
FP-301811 - WR-GAS SCADA Cyber Security	166,829	Analyzing; possible late 2015 Start
FP-301813 - WR-GAS SCADA Enhancements	233,259	In Process; approvals received
FP-302579 - PII - Personal Info Security	115,614	In Process
FP-302616 - Human Capital Management	35,693	In Process; Phase II complete Fall 2015
FP-302621 - LV Customer Website	11,842	In Process; est. complete 4th qutr '15/1st qtr '16
FP-302626 - ECM Upgrade	68,388	Waiting for ETS response
FP-306935 - Gas Analytics	13,549	Moved to later budget year
FP-306967 - District Office Access Control Sys	334,285	In Process
FP-309301 - Yakima Training Facility	564,300	Preliminary costs in 2015; majority of project cost moved to 2016/later
Grand Total	18,347,961	

** Blanket Funding Projects are annual estimates of spending for projects/items with costs under $ 100,000 that have been aggregated together into one budgeting bucket called a "Funding Project". The status of "blanket" has been used to denote those projects for this data request.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 312

Date prepared: 7/9/2015

Preparer: Becky Mellinger, Scott Wanner

Contact: Pamela Archer

Telephone: (509)-734-4591

312. With regard to the Company's response to Staff Data Request No. 237, please provide for all projects with a "Blanket" status the amount spent on those projects annually from 2010 through 2013.

Response:

See attached file entitled "A312 – 318.xlsx"

312. With regard to the Company's response to Staff Data Request No. 237, please provide for all projects with a "Blanket" status the amount spent on those projects annually from 2010 through 2013.

Power Plan Funding Project	JDE Project	2013	2012	2011	2010
FP-101170	BOR376G	182,502.71	(176,360.74)	(107,480.92)	114,490.19
FP-101171	BOR376N	39,716.24	-	-	6,145.36
FP-101172	BOR376R	200,131.45	153,525.69	87,975.96	99,983.92
FP-101173	BOR378G	-	-	11,904.19	20,201.59
FP-101175	BOR378R	186,231.38	18,407.22	68,479.41	45,214.68
FP-101176	BOR380G	1,363,424.65	817,662.27	500,448.02	493,846.95
FP-101180	BOR385G	78,691.63	21,361.80	40,668.44	55,550.44
FP-101181	BOR385R	14,073.06	36,579.71	7,030.95	-
FP-101184	BOR392V	251,383.25	462,439.89	359,734.96	216,421.82
FP-101186	BOR396V	47,065.60	300,145.19	106,190.03	(14,482.30)
FP-101218	B041394E	-	34,012.08	34,044.56	8,350.86
FP-101234	B042390F	-	-	7,940.62	-
FP-101237	B042394E	-	48,877.47	31,524.97	2,251.06
FP-101255	B043394E	6,436.84	20,209.73	33,595.78	2,257.84
FP-302370	N/A	-	-	-	-
FP-101164	BIN397E	105,311.06	14,465.21	540.54	151,407.38
FP-101209	BIN303T	-	-	14,271.50	7,720.22
FP-101210	BIN381G	1,273,849.38	680,813.85	1,277,984.81	347,355.04
FP-101215	BIN392V	234,543.28	162,909.31	243,666.81	151,253.03
FP-101216	BIN394E	74,025.13	61,976.50	60,690.66	22,800.82
FP-101259	BIN383G	347,537.58	405,429.10	283,332.35	259,204.00
FP-200661	N/A	94,230.04	-	-	-
FP-200662	N/A	203,360.36	-	-	-

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 184

Date prepared: 6/3/2105

Preparer: Jeremy Ogden

Contact: Pamela Archer

Telephone: (509)-734-4591

184. With regard to CNG/100, Madison/3, line 13, please provide further explanative detail regarding the 2011 requirement from the Department of Transportation and the process prepared by Cascade for evaluating physical conditions of its distribution pipelines.

Response:

The requirements for each operator to follow with regards to integrity management were added to CFR Part 192 on December 4, 2009, and were required to be implemented by August 1, 2011. When the requirements were added to federal code in 2009, Cascade began writing its Distribution Integrity Management Plan (DIMP). This plan was written to cover how Cascade would gather data on its facilities, how that data would be analyzed, and what the responses to that analysis would be.

Data gathering was accomplished through a review of historical forms covering Cascade's existing facilities. Subject Matter Experts (SMEs) were also interviewed to gather more information. Both of these sources of information were field verified through Exposed Pipe Reports which collected data on facilities as they were observed.

The gathered information was input into a GIS-based risk model for analysis. Exposed Pipe Reports were also used to verify model results. Cascade's first DIMP plan was completed in 2011 and audited in 2012.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 313

Date prepared: 7/9/2015

Preparer: Becky Mellinger

Contact: Pamela Archer

Telephone: (509)-734-4591

313. With regard to the Company's response to Staff Data Request No. 237, please identify any projects that have been delayed, postponed, or are otherwise not expected to be completed and put into service prior to December 31, 2015. Please also provide explanation for any projects identified.

Response:

See attached file entitled "A312 – 318.xlsx"

DR 313 In reference to DR 237 - projects that have been delayed, postponed, or otherwise not expected to be completed and put into service by December 31, 2015.
(Starting document is DR 237 Current Project status reports for each 2015 Capital Project as referenced in DR135)

Row Labels	2015 Approved Budget	Status as of DR 237	Status as of DR 313 (June 30,2015)
OR			
FP-101170 - MAIN-GROWTH-OREGON	489,544	Blanket	Blanket
FP-101171 - MAIN-REINFORCE-OREGON	122,853	Blanket	Blanket
FP-101172 - MAIN-RELO-REPL-OREGON	339,192	Blanket	Blanket
FP-101173 - R STA-GROWTH-OREGON	108,253	Blanket	Blanket
FP-101175 - R STA-RELO-REPL-OREGON	122,687	Blanket	Blanket
FP-101176 - SERV-GROWTH-OREGON	1,146,321	Blanket	Blanket
FP-101180 - IND M&R-GROWTH-OREGON	98,197	Blanket	Blanket
FP-101181 - IND M&R-REMOVE&REPLACE-OREGON	49,315	Blanket	Blanket
FP-101184 - GP TRAN. VEHICLE - OREGON	709,846	Blanket	Blanket
FP-101186 - GP POWER EQUIP - OREGON	287,968	Blanket	Blanket
FP-101218 - GP TOOLS - BEND	49,763	Blanket	Blanket
FP-101234 - GP BUILDINGS - PENDLETON	38,945	Blanket	Blanket
FP-101237 - GP TOOLS - PENDLETON	17,309	Blanket	Blanket
FP-101255 - GP TOOLS - ONTARIO	29,533	Blanket	Blanket
FP-200282 - R STA - SUN RIVER GATE UPGRADE	2,317,813	In Process-Design	Moved to 2016
FP-200688 - BEND PIPE REPL	2,450,964	In Process-Bidding	2015
FP-200689 - RPL 12" BEND HP LINE #1	1,551	Moved to later budget year	moved to later budget year
FP-302000 - Baker City Office Purchase	43,272	In Process-Final Work	2015
FP-302370 - GB - GROUNDBED OREGON	426,546	Blanket	Blanket
FP-302650 - O-4 UMATILLA	208,223	In Process-Design	2015
FP-302651 - O-6 ATHENA	211,111	In Process-Design	Moved to 2016
FP-302656 - PENDLETON R-9 REPLACEMENT	208,138	In Process-Design	Moved to 2016
FP-302714 - PENDLETON V-23 REPLACEMENT	87,109	In Process-Design	Est Completion 2016
FP-307026 - ONTARIO 6" IP REPLACEMENT	303,175	Complete	Complete
FP-309300 - REPLACE O-3 HERMISTON	174,005	In Process-Design & Procurement	2015
Allocated			
FP-101164 - GP COMM EQUIP - INTERSTATE	357,619	Blanket	Blanket
FP-101209 - INTANGIBLES - SOFTWARE	129,262	Blanket	Blanket
FP-101210 - PRE-CAP MTR-GROWTH-INTERSTAT	1,760,984	Blanket	Blanket
FP-101215 - GP TRAN. VEHICLE - INTERSTAT	145,675	Blanket	Blanket
FP-101216 - GP TOOLS - INTERSTATE	202,146	Blanket	Blanket
FP-101259 - PRE-CAP REG-GROWTH-INTERSTAT	263,204	Blanket	Blanket
FP-101472 - UG-INSTALL WORK MGT-GLE	325,338	In Process	In Service 2017
FP-101478 - AUTOMATED VEHICLE LOCATION SYS	112,007	Moved to later budget year	Moved to 2016
FP-101479 - UG MWM PROJECT - CNGC SHARE	195,808	In Process	In Service 2017
FP-101481 - UG GPSLS PRDJECT - SOFTWARE	28,923	Delayed; projected 2016 Start	Moved to 2016
FP-101510 - UG GMS PURCHASE SOFTWARE	110,086	In Process (late June 2015)	2015
FP-200064 - IVR-WEB IMPLEMENTATIION - DRCT	257,382	In Process; estimate complete late F	2015 For Cascade
FP-200155 - UG GPSLS PROJECT - HARDWARE	332	Minimal	N/A
FP-200352 - CC&B COSTS	1,622,715	In Process	2015
FP-200661 - DATA CENTER/NETWORKING EQUIP	96,065	Blanket	Blanket
FP-200662 - PC SUPPORT EQUIPMENT	508,451	Blanket	Blanket
FP-200663 - UG GIS ENHANCEMENTS CNG DIRECT	668,571	In Process	In Service; Ongoing upgrades
FP-301811 - WR-GAS SCADA Cyber Security	166,829	Analyzing; possible late 2015 Start	In Service; Ongoing upgrades
FP-301813 - WR-GAS SCADA Enhancements	233,259	In Process; approvals received	In Service; Ongoing upgrades
FP-302579 - PII - Personal Info Security	115,614	In Process	Est Completion 2017
FP-302616 - Human Capital Management	35,693	In Process; Phase II complete Fall 2015	
FP-302621 - LV Customer Website	11,842	In Process; est. complete 4th qutr '1!	2015
FP-302626 - ECM Upgrade	68,388	Waiting for ETS response	
FP-306935 - Gas Analytics	13,549	Moved to later budget year	moved to later budget year
FP-306967 - District Office Access Control Sys	334,285	In Process	2015
FP-309301 - Yakima Training Facility	564,300	Preliminary costs in 2015; majority of	Prelim cost 2015; majority 2016
Grand Total	18,347,961		

**** Blanket Funding Projects are annual estimates of spending for projects/items with costs under $ 100,000 that have been aggregated together into one budgeting bucket called a "Funding Project". The status of "blanket" has been used to denote those projects for this data request.**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 315

Date prepared: 7/9/2015

Preparer: Becky Mellinger

Contact: Pamela Archer

Telephone: (509)-734-4591

315. With regard to the Company's response to Staff Data Request No. 237, please identify the expected in-service date for each project not listed as "Blanket." For any project with an expected in-service date after December 31, 2015, please provide narrative description or supporting documentation justifying why it should be included in the test year for the purpose of setting rates.

Response:

See attached file entitled "A312 – 318.xlsx"

DR 315 In reference to DR 237 - not including "blankets" identify expected in-service dates for projects. For any projects expected to be put into service by December 31, 2015, please provide narrative description or supporting documentation justifying why it should be included in the test year for the purpose of setting rates.
(Starting document is DR 237 Current Project status report for each 2015 Capital Project as referenced in DR135)

Row Labels	2015 Approved Budget	Status as of DR 237	Status as of DR 313 (June 30,2015)
OR			
FP-101170 - MAIN-GROWTH-OREGON	489,544	Blanket	Blanket
FP-101171 - MAIN-REINFORCE-OREGON	122,853	Blanket	Blanket
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FP-200282 - R STA - SUN RIVER GATE UPGRADE	2,317,813	In Process-Design	Moved to 2016
FP-200688 - BEND PIPE REPL	2,450,964	In Process-Bidding	2015
FP-200689 - RPL 12" BEND HP LINE #1	1,551	Moved to later budget year	moved to later budget year
FP-302000 - Baker City Office Purchase	43,272	In Process-Final Work	2015
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FP-302650 - O-4 UMATILLA	206,223	In Process-Design	2015
FP-302651 - O-6 ATHENA	211,111	In Process-Design	Moved to 2016
FP-302656 - PENDLETON R-9 REPLACEMENT	208,138	In Process-Design	Moved to 2016
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FP-307026 - ONTARIO 6" IP REPLACEMENT	303,175	Complete	Complete
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FP-200352 - CC&B COSTS	1,622,715	In Process	2015
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FP-200662 - PC SUPPORT EQUIPMENT	508,451	Blanket	Blanket
FP-200663 - UG GIS ENHANCEMENTS CNG DIRECT	668,571	In Process	In Service; Ongoing upgrades
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FP-302579 - PII - Personal Info Security	115,614	In Process	Est Completion 2017
FP-302616 - Human Capital Management	35,693	In Process; Phase II complete Fall 2015	
FP-302621 - LV Customer Website	11,842	In Process; est. complete 4th qtr. '15	2015
FP-302626 - ECM Upgrade	68,388	Waiting for ETS response	
FP-306935 - Gas Analytics	13,549	Moved to later budget year	moved to later budget year
FP-306867 - District Office Access Control Sys	334,285	In Process	2015
FP-309301 - Yakima Training Facility	564,300	Preliminary costs in 2015; majority ol	Prelim cost 2015; majority 2016
Grand Total	18,347,961		

**** Blanket Funding Projects are annual estimates of spending for projects/items with costs under $ 100,000 that have been aggregated together into one budgeting bucket called a "Funding Project". The status of "blanket" has been used to denote those projects for this data request.**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 311

Date prepared: 7/10/2015

Preparer: Becky Mellinger, Jeremy Ogden

Contact: Pamela Archer

Telephone: (509)-734-4591

311. With regard to the Company's response to Staff Data Request No. 237, please provide for all projects with a 2015 budgeted cost over $0.5 million that are not listed as "Blanket" (FP-200282, FP-200688, FP-200352, FP-200663, FP-309301) the following:

a. Project justification forms or other supporting documentation from field personnel justifying the necessity of the proposed projected;
b. The annual amount spent on each project from its inception through the present;
c. Any presentation or manager approval used to justify the undertaking of the project;
d. A narrative discussing how DIMP was used in the selection of the project;
e. Any other supporting documentation identifying, demonstrating, or justifying why the project is necessary or prudent to be carried out at this time.

Response:

a. FP 200282 – The Sun River gate is being upgraded to meet increased demands. I have attached an email from Kathleen Chirgwin, the engineer serving the Bend District, detailing the pressure alarms that we have at the Sun River Gate due to demands.

FP 200688 – The Bend Bare Steel Replacement projects are driven by DIMP. The DIMP output is attached as "A311 a - FP 200688 (1).pdf" and "A311 a - FP 200688 (2).pdf". The first file is the original DIMP output for Bend in 2013 and the second file is an updated 2015 run after earlier phase completions.

FP 200352 – The CC&B project is a utility group project, meaning that all four utilities are implementing the software. Costs are shared accordingly. Go-Live for the software was staggered with Cascade going live in 2010, at which time CNGC's share of the costs were capitalized. As the other utilities proceed with implementation CNGC continues to receive its share of the total costs.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

FP 200663 – Continuing updates to the GIS system for CNGC. Includes additional functionality and Land base enhancements.

FP 309301 – Yakima Training Facility is a training ground for operations personnel to develop consistent, up-to-date, installation and maintenance standards. The training center will allow for consistently trained personnel in order to perform their jobs in a safe and consistent manner. Having the facility readily available will be convenient and avoid external training costs.

b. See attached spreadsheet entitled "A311 b-e.xlsx". Note that FP 200282 and FP 309301 have been postponed until 2016, therefor there are no costs include in the 2015 column.

c. FP 200282 – The Sun River Gate project has been delayed until next year due to concerns about forest fires in the area. For that reason it has not yet been approved in Power Plan.

FP – 200688 - The original email providing approval for the preliminary costs for 2013 phase of this project is provided as "A311 c – FP-200282.pdf". In May of 2013 CNGC implemented Power Plan and approval was granted through Power Plan, rather than email and JDE. The approvals for the 2014 and 2015 WOs are attached. Se files attached as "A311 c – FP-200282.pdf (1)", "A311 c – FP-200282.pdf (2)", "A311 c – FP-200282.pdf (2.1)", "A311 c – FP-200282.pdf (3)", and "A311 c – FP-200282.pdf (3.1)"

d. The Bend Bare Steel Replacement projects (FP-200688) is a multi-year project that will replace bare steel and pre-CNG pipe in the City of Bend, Oregon. This project was selected based on the output of Cascade's DIMP. Information gathered from field observations and Subject Matter Experts (SMEs) was entered into a GIS-based risk model and the output showed that the town of Bend had the highest risk score in Oregon.

e. See attached spreadsheet entitled "A311 b-e.xlsx".

311. With regard to the Company's response to Staff Data Request No. 237, please provide for all projects with a 2015 budgeted cost over $0.5 million that are not listed as "Blanket" (FP-200282, FP-200688, FP-200352, FP-200663, FP-309301) the following:

a. Project justification forms or other supporting documentation from field personnel justifying the necessity of the proposed projected;

b. The annual amount spent on each project from its inception through the present;

		Year									
Funding Project	Wor Order	2015	2014	2013	2012	2011	2010	2009	2008	2007	
FP-200282	166628	-	-	-	-	-	-	-	-	-	Sun River Gate Upgrade
FP-200688	Multiple	144,651.81	2,554,332.23	1,757,087.03	-	-	-	-	-	-	Bend Pipe Replacement
FP-200352	Multiple*	986,109.79	1,937,492.24	1,912,040.05	3,741,143.17	2,370,442.42	2,598,206.03	1,018,361.73	3,302,268.06	1,378,862.71	Utility Group CC&B Implementation - See below for item (e.) for this project
FP-200663	Multiple	17,105.14	61,921.27	118,713.69	-	-	-	-	-	-	Utility Group GIS Enhancements
FP-309301	N/A										Yakima Training Facility

*Funding project FP-200352 is for the implementation of CC&B. This implemenation was initiated prior to PowerPlan and even JDE. Driven by the mechanics of the implementations of JDE and PowerPlan only WO 173060 rolls up to this funding project, but all work orders are being included for purposes of this data request.

e. Any other supporting documentation identifying, demonstrating, or justifying why the project is necessary or prudent to be carried out at this time.

Funding Project FP-200352

The CC&B project is a utility group project, meaning that all four utilities are implementing the software and costs are shared accordingly. Go-Live for the software was staggered with Cascade going live in 2010, at which time CNGC's shared costs were capitalized. As the other utilities proceed with the implementation CNGC continues to receive its share of their costs. Therefore costs being seen now are ongoing utility group implementation costs that began back in 2007 as opposed to something that determined "necessary or prudent to be carried out at this time".

CASE: UG 287
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

Exhibits in Support
Of Opening Testimony

July 31, 2015

This page is confidential.

You must have signed the Protective Order No: 15-094

in Docket No. UG 287 to view this page.

CASE: UG 287
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 704
(ELECTRONIC ONLY)

Exhibits in Support Of Opening Testimony

July 31, 2015

CASE: UG 287
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 705
(ELECTRONIC ONLY)

Exhibits in Support
Of Opening Testimony

July 31, 2015

CASE: UG 287
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

July 31, 2015

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

A. My name is Matt Muldoon. 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/801.

Q. What is the purpose of your testimony?

A. I examine four issues regarding Cost of Capital (CoC) in this docket:

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

I also examine a separate topic:

5. Allocations

Q. Cascade filed for: 1) 51 percent Common Equity (Equity) / 49 percent LT Debt Capital Structure, 2) 9.55 percent ROE, and 3) 5.30 percent Cost of LT Debt. Does your analysis support these proposals?[1]

A. Yes. I recommend that the Commission adopt the Company's proposed values for Capital Structure, ROE, and LT Debt. The Company's proposals are reasonable in aggregate and in detail.

Q. Cascade calculated that the cost of capital parameters equate to a ROR of 7.47 percent.[2] Did you generate the same inputs and finding?

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1 Please note that the Company has no outstanding preferred stock.

2 See CNG/200, Chiles/2 at lines 1–6.

A. Yes.

Q. Why do you support Cascade's Cost of Capital recommendations?

A. There are a number of reasons, but primarily because proposed values are:

1. Derived using input assumptions acquired from unbiased referent sources;
2. Reflective of an appropriately screened peer group of like gas utilities;
3. Consistent with results of Staff's modeling;
4. Supportable for a utility that files infrequent rate change requests; and
5. Informed by Exhibit Staff/808 Confidential risk assessment.

Q. How long has Staff been analyzing issues related to Cascade's cost of capital?

A. Staff has been performing analysis for several months beginning prior to Cascade's filing because Staff was aware of Cascade's requirement to file a general rate case.

Q. How is your testimony organized?

A. My testimony is organized as follows:

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

A. Yes. I prepared the following other exhibits:
Staff/802 .... Staff Peer Screening
Staff/803 .... Staff Three Stage DCF Modeling
Staff/804 .... Staff Synthetic Forward Curve TIPS Analysis
Staff/805 .... Staff Historical GDP Analysis with BEA Data
Staff/806 .... **CONFIDENTIAL** Cost of LT Debt Table
Staff/807 .... Value Line (VL) Gas and Water Utility Industry Profiles
Staff/808 .... **CONFIDENTIAL** Risk Assessment

Q. Does Staff's recommended ROE meet appropriate legal and policy standards?

A. Yes. The ROE that I recommend meets the U.S. Supreme Court cases *Hope* Natural Gas[3] (Hope) and *Bluefield* Waterworks[4] (Bluefield) standards, as well as the requirements of Oregon Revised Statue (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]

ISSUE 1 – CAPITAL STRUCTURE

Q. Why is a Capital Structure of 51 percent Equity reasonable?

A. This Capital Structure is based on the Cascade-provided Equity and LT Debt for the test year as well as two prior and two subsequent years.[6]

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[3] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[4] Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692-693 (1923).

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

[6] Please see Confidential Exhibit CNG/201 Chiles for Long Term Debt / Equity and Debt Issuance.

Q. Does a 51 percent Equity Capital Structure represent a fact-based actual Capital Structure rather than one assumed or targeted?

A. Yes.

ISSUE 2 – COST OF COMMON EQUITY (ROE)

Q. Did you prepare tables showing current, Company proposed, and Staff proposed overall cost of capital?

A. Yes, the following tables provide that information.

Table 1

CNG Current Authorized (UG 173 Order No. 07-220)			CNG
Component	**Percent of Total**	**Stipulated or Implied Cost**	**Weighted Average**
Long Term Debt	55.00%	7.57%	4.165%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	45.00%	10.100%	4.545%
	100.00%		**8.710%**

Table 2

CNG Requested – UG 287		CNG Direct Testimony		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**49.00%**	**5.300%**	2.597%	**-1.242%**
Preferred Stock	0.00%		0.000%	
Common Stock	**51.00%**	**9.550%**	4.871%	
	100.00%		**7.468%**	
The Company rounds to 7.47% ROR, which Staff finds reasonable.				

Table 3

Staff Summary – UG 287		Staff Recommendation		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	49.00%	5.300%	2.597%	
Preferred Stock	0.00%		0.000%	-1.242%
Common Stock	51.00%	9.550%	4.871%	
	100.00%		7.468%	

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

A. I rely on two different multistage DCF models,[7] applied using a cohort group of peer utilities, to estimate the expected return on common equity required by Company 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 varied peer groups and input parameters to test the reasonableness of my modeling.

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 return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.[8] A DCF model has three primary

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[7] *See* Order No. 01-777, at page 2 in Docket No. UE 115, Commission discussion of multistage versus single-stage DCF models.

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

components: a current stock price, an expected dividend, and an expected growth rate in dividends.[9]

Staff infers the required ROE by applying its three-stage DCF models to a comparable sample of gas utilities. Cascade is wholly owned by MDU and hence is not publicly traded. Therefore my analysis will be based on proxy companies similar in risk profile and operations as Cascade.

Q Describe the two different multi-stage DCF models that you used.

A. The first 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" (Model X). The second is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (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 share to be received in the years 2014 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) 2014-2019, where I use Value Line's forecasts of dividends per share for each company; 2) 2020-2024, wherein the rate of dividend growth converges from the average rate over the 2014-2019 period to the growth rate in of the third stage; which is, 3) 2025-2044. Model X includes a terminal value calculation, in which I assume

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9 Order No. 07-015 at 32.

dividends per share grown indefinitely at the rate of growth in Stage 3 ("growing in perpetuity"). In contrast, Model Y terminates in a sale of stock wherein 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 in the most recent NW Natural general rate case, Docket No. UG 221.[10] 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 (VL) estimates of future dividends are available. I use five years for Stage Two as that seems a reasonable length of time for individual companies' Stage One dividend growth rates to converge to the Stage Three growth rate, which is representative of all gas utilities. I discuss the mechanics of this convergence below. I use about 20 years for Stage Three, corresponding to forward projections from federal sources, and calculate a terminal valuation for the sale of each company's stock in 2044.

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.

[10] UG221 Staff/1300, Storm/64.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values[11] 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 to calculate an adjustment for differences in capital structure between each peer utility and the Company-proposed and Staff-supported capital structure for Cascade.[12]

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 of 2015.

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 2044. This is a common approach in multistage DCF models.

Model Y uses the current price-earnings (P/E) ratio[13] multiplied by the estimated earnings per share (EPS) in 2044, which establishes the stock's

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

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

"selling price" in 2044 for terminal valuation. I estimate the 2044 EPS analogously with methods used to estimate the 2044 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 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. In this way Model X provides a check on Model Y and vice-versa.

PEER SCREEN

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

A. I used companies that meet the following criteria as peer utilities to the regulated gas utility activities of Cascade Natural Gas Corp.:

1. Covered by VL as a gas utility;
2. Forecasted by VL to have positive dividend growth;
3. S&P LT issuer credit rating greater than or equal to BBB–, or Moody's issuer credit rating greater than or equal to Baa3;
4. No decline in annual dividend in last five years based on SNL;
5. Has 80 percent or greater regulated assets *per* SEC filings;

[13] "Current" in this context means the price obtained, as previously described, divided by Value Line's estimated 2015 earnings per share (EPS); i.e., it is a forward P/E, not an historical P/E.

6. Has less than 56 percent LT Debt in VL capital structure; and
7. Has no recent or imminent merger and acquisition activity.

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

A. There is evidence that investors find common stock of dividend-cutting utilities less attractive. The FPL Group's Florida Power and Light and Niagara Mohawk Power Corporation stock prices declined sharply after dividend cuts.[14] These real world findings are consistent with Staff's screening out gas utilities that have recently cut dividends.

Q. What cohort of companies resulted from your screens?

A. Please see Staff/802 Muldoon/1-2 for detailed Staff screens and also for a table that shows the list of peer utilities obtained by Staff screens.

Q. Occasionally utilities float the idea of cutting dividends in the news to test whether this sentiment still exists. What happened on November 1, 2012, as Exelon floated that it was considering cutting its dividend to fund stock buy backs and possible acquisitions?

A. Before and after that date the utility said that its dividend was safe and reliable. The day after Exelon tested the idea of cutting its dividend, Exelon common stock fell 6 percent. Apparently, that feedback was sufficient to

[14] 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.

cause the utility to reassure investors that there had only been misunderstood communication and that the dividend was, as ever, safe and reliable.[15]

SENSITIVITY ANALYSIS

Q. In this case, does Staff consider a peer group that consists of all Value Line tracked publicly traded gas utilities?

A. Yes. Staff included it as a sensitivity case because this group is regularly proposed in direct testimony by gas utilities seeking general rate increases.[16] Water companies can also be a proxy group for natural gas operations as well. In fact, I use water utilities in my sensitivity analysis.

Q. Why do you include publicly traded U.S. water utilities in your sensitivity analysis?

A. Water utilities screened by the same criteria as gas utilities may offer a larger pool of potential peers.

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

A. No. However, the results of my sensitivity analyses inform the Commission and provide a check of reasonableness for recommendations herein.

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15 See Crain's Chicago Business article, "Exelon Shares Slump as It Mulls Cutting Dividend" of November 1, 2012 regarding the impacts of CEO Chris Crane's floated idea of cutting the Exelon dividend. Both institutional and individual investors started rapidly selling as the Company explained quickly that the press had misunderstood Exelon's intent to possibly cut dividends six months from then.

16 See the Avista general rate case filing in Docket No. UG 284.

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. I refer specifically to the long-term growth rate for multistage DCF models such as the models I use.

Q. What is the trend on investor expectation incorporated in these models?

A. Investors are seeing a broad consensus of referent sources projecting lower than historical GDP growth rates in both the short and long-term.

Q. What long-term growth rates do you use in the two DCF models? [17]

A. I used multiple different long-term growth rates shown in Figure 1 below.

The first method uses a 50 percent weight applied to the average annual growth rate resulting from estimates of long-term Gross Domestic Product (GDP) by the EIA, the OMB, and the CBO, with each receiving one-third of the 50 percent weight.[18] The remaining 50 percent is the average annual

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[17] 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 Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

[18] The EIA is the Energy Information Administration within the U.S. Department of Energy, 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, e.g., 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 2.35 percent, based on an averages 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.

historical real GDP growth rate, established using regression analysis, for the period 1980 through 2014,[19] to which I apply the TIPS inflation forecast.

Figure 1

UG 287 Staff ROE Growth Rates and Modeling Results

Stage 3 – Long-Term Annual Dividend Growth Rate					
Component	**Real Rate**	**TIPS Inflation Forecast**	**Nominal Rate**	**Weight**	**Weighted Rate**
EIA			4.89%	16.70%	0.82%
OMB			4.61%	16.70%	0.77%
CBO			4.55%	16.70%	0.76%
Historical 1980 – 2014	2.93%	2.35%	5.35%	50.0%	2.67%
Composite				100%	**5.02%**
Historical 1980 – 2014 Q4			5.35%	100.0%	**5.35%**
Indiana / Top 10 Blue Chip			5.78%	100.0%	**5.78%**
GDP Growth Rates Also Considered:					
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%**

Q. **Do these growth rates retain 2014 expectations while addressing a substantial drop in expectations of long-term GDP occurring in second quarter of 2015?**

A. Yes

Q. Are there many material trends in the growth inputs since the Company last filed a rate case in August 2006 in Docket No. UG 173?

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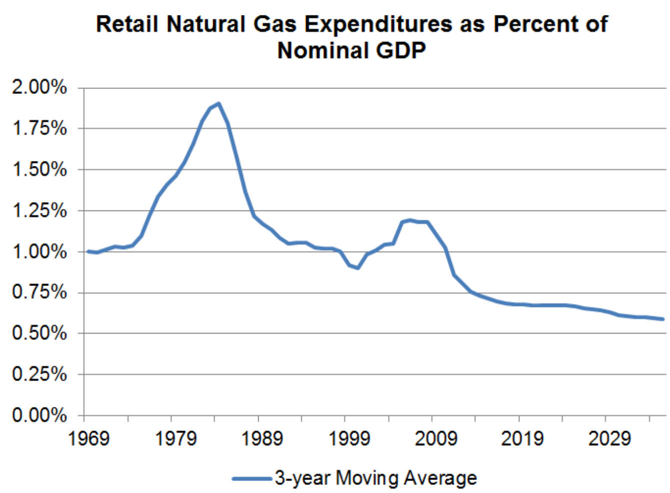
[19] Staff discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. See, e.g., Docket No. UE 233 Exhibit Staff/800, Storm/46, line 15 through Storm/50 line 3.

A. Yes, for example:

1. Historical GDP rose due to inclusion of creative works back to 1929;
2. Investors' expectation of inflation dropped substantially; and
3. The U.S. Social Security Administration (SSA) projects lower population growth and no delayed productivity surge following the 2008 great recession.

In aggregate, these and other drivers narrowed expectations, and lowered highest expected GDP growth. This is consistent with US Congressional Budget Office (CBO) and other findings.

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



A. Yes. Based on information from the U.S. Energy Information Administration (EIA), gas use per dollar of GDP has been declining for years and EIA expects the decline to continue.[20]

Q. Do you use an annual rate of long-term growth less than that estimated for GDP, given the EIA's outlook for the industry illustrated above?

20 Historical retail expenditures result from retail prices in the EIA's Annual Energy Review's Table 6.8 and quantities in Table 6.5. Estimated future retail expenditures are based on EIA's Annual Energy Outlook's (early release) "Natural Gas Supply, Disposition, and Prices." Historical GDP is from the U.S. Bureau of Economic Analysis.

A. I do not. Arguably, the EIA outlook supports a lower annual growth rate. But, Staff uses the GDP growth rate as conservative ceiling value.

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

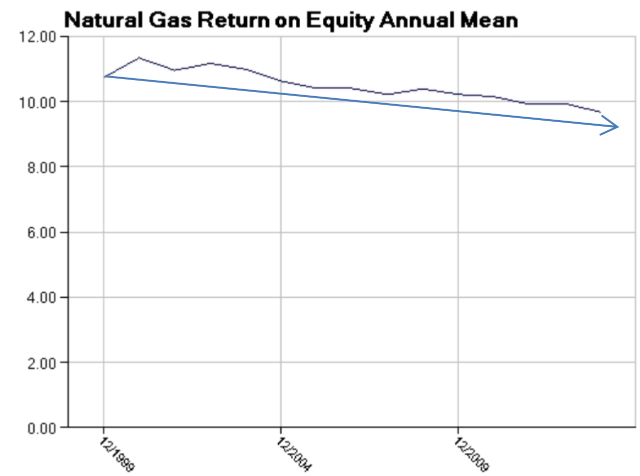
A. Please see Exhibit Staff/803 for a summary followed by modeling detail.

Q. How do these estimated ROE values compare with national historical gas utilities' authorized ROE values?

A. The top of my range of estimated required ROEs is eight basis points lower than the current year-to-date average for regulated gas utilities' authorized return on equity. For gas utilities, allowed ROEs averaged 10.19 percent in 2009, fell to 9.94 percent in 2012, declined further to 9.68 percent in 2013, and continued to decline through the 12-months-ended Sept. 30, 2014, to 9.63 percent.[21] There has been a consistent downward trend in average gas utility authorized ROEs in recent years.

[21] See "Earnings per Share Comparisons for the Third Quarter, Year-to-date, and 12-months ended Sept. 30, 2014" by Rob Schain of Regulated Research Associates (RRA), an affiliate of SNL Financial LC released Nov 24, 2014.

Figure 2 – SNL Gas ROE Downward Trend[22]



Q. What is your recommended ROE for COMPANY inclusive of flotation costs?

A. I recommend a range for consideration of 8.67 percent to 9.55 percent with a midpoint of 9.11 percent.

Q. What is the Company's requested ROE?

A. Cascade requested an authorized ROE of 9.55 percent.

Q. What is your assessment of the Company's proposed ROE?

A. Cascade's proposed ROE is supportable and consistent with mainstream growth estimates utilized in Staff's modeling.

Q. The Commission's decision regarding a just and reasonable point value for ROE may hinge on growth rates. Did your analysis include the construction of a synthetic forward curve using UST TIPS break even points?

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22 Staff Accessed SNL Rate Case Statistics on November 21, 2014 at https://www.snl.com/interactivex/RateStatisticsGraph.aspx?Service=1.

A. Yes. My forward curve is provided in Exhibit Staff/804, reflecting implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of diminished future inflation.

Q. Did Staff examine a historical GDP growth trend?

A. Yes, Staff extracted and ran a regression on 1980 through 2014 data from US Bureau of Economic Analysis (BEA) to generate the annual real historical GDP growth rate shown in Table 5. Staff's recommended range of ROEs includes values presuming GDP growth over the next thirty years would look like that of the past 30 years?

Q. Does Staff show this analysis in its exhibits?

A. Yes. Exhibit Staff/805 shows Staff's analysis in support of this finding.

Q. Are Staff's positions corroborated by Federal Sources?

A. Yes. Staff inputs are consistent with Federal, academic and business referent sources.

Q. If utilities' dividends and earnings per share 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. Utilities are not becoming a larger and larger part of the U.S. economy according to Standard and Poor's GICS Sector Scorecard of April 4, 2014 in Figure 3 below.[23]

[23] Staff accessed Standard and Poor's sector data on June 3, 2014 at: http://us.spindices.com/indices/equity/sp-500.

Figure 3 – Utilities' Share of S&P Market Index

MARKET REPRESENTATION	2007	2008	2009	2010	2011	2012
Utilities	3.62%	4.19%	3.71%	3.30%	3.87%	3.43%

Q. What changes does Staff see in modeling inputs for recent general rate cases?

A. Federal estimates of GDP growth whether short-, medium-, or long-term are down from a year ago. Federal estimates of population growth over all three time frames are also down. And no bounce following the economic downturn of 2008 has occurred.[24] Meanwhile low fixed income returns and losses in 2013 heighted investment in steady dividend stocks.[25]

CHECK OF REASONABLENESS

Q. What control modeling does Staff perform to corroborate DCF results?

A. I examined multiple peer groups and growth rates to validate modeling results. Model X validates Model Y and vice-versa.

EQUITY FLOTATION COSTS

Q. Has Staff included an upward adjustment to ROE to account for equity flotation costs?

A. Yes. Staff includes 12.5 bps addressing long-term equity flotation costs in its recommended range of reasonable ROE's.

24 "Economy Starts Year with Whimper" by Eric Morath and Ben Leubsdorf, WSJ, May 1, 2014.

25 "Investors Just Want to Get Paid" by Richard Barley, WSJ, Monday, May 12, 2014.

OUTBOARD ADJUSTMENTS OF MODELING RESULTS

Q. Why is application of the Hamada Equation to un-lever peer utility capital structures and to re-Lever at Cascade's target capital structure reasonable?

A. Staff usually employs the Hamada Equation. As earlier discussed, Staff's screening criteria already identify peers that have very close capital structure to the Company. Use of the Hamada adjusted results helps insure that Staff has captured all material risk in its analysis.

TRACTION WITH INVESTORS

Q. What assurance does the Commission have that your viewpoint has any practical traction with investors, financial managers and analysts?

A. Warren Buffett defines intrinsic value as: "the discounted value of the cash that can be taken out of a business during its remaining life."[26] For an investor without control of the business, the value of a stock is the discounted value of the cash flows that are realized while that stock is held (dividends), plus the discounted proceeds from any sale of the stock.[27] This approach is dispassionate, is the standard in Oregon, and constructively informs decision making.

Q. Please recap your thinking.

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[26] See Warren Buffett's discussions in the 2012 Berkshire Hathaway, Inc., New York Stock Exchange (NYSE) ticker symbol (BRK) annual reports regarding intrinsic BRK value.

[27] "Ruminations on Risk" by Michael Mauboussin and Alexander Schay, US Investment Strategy, Valuation Strategy, August 3, 2001. Please note that this publication is supported in part by Credit Suisse and First Boston.

A: Staff's criteria used to develop its proxy group reflects objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, and exposure to company specific factors. As a result, investors are likely to regard this group as having risks and prospects comparable to the Company.

Q. What kind of investors hold peer utility stock?

A: The majority of shares of peer companies examined in Exhibit Staff/807 are held by relatively few sophisticated institutional and mutual fund owners. For example, just 185 institutions hold shares of NW Natural Gas Company.

Q. Summarize the role of DCF modeling?

A: Staff's three-stage DCF models replicate market valuation that sets the price investors are willing to pay for a share of the Company's stock. By estimating the present value of the future cash flows investors expect to receive from the stock as dividends and capital gains, Staff estimates investors' required rate of return. This allows the Commission to back into the range of discount rates or cost of equity sophisticated investors implicitly used in bidding the stock up to that target price.

Q. Please provide a table summarizing your ROE analysis and estimates.

A: Table 4 below shows Staff ROE estimates.

TABLE 4 – STAFF HAMADA ADJUSTED ROE ESTIMATES

Staff Peer ROE Range from:		8.54%	to	9.43%
Upward Equity Flotation Cost Adjustment		+	0.125%	
Range of Reasonable ROE's		**8.67%**	to	**9.55%**
Midpoint			**9.11%**	

Q. How does the frequency of Cascade's general rate case filings inform Staff's understanding of modeling results?

A: Cascade's infrequent rate case filings are consistent with the upper end of Staff's range of reasonable ROE's

Q. How do rating agency assessments in Staff Exhibit 808 inform results?

A: Rating agency assessments are consistent with the Upper end of Staff's range of reasonable ROE's.

ISSUE 3 – COST OF LT DEBT

Q. What is the basis for Staff's recommendation for 5.30 percent Cost of LT Debt?

A. Staff researched Cascade's debt using Bloomberg resources. Staff also built and analyzed its usual spreadsheets to analyze this data. Please see Confidential Exhibit Staff/806 Muldoon/1. Staff's analysis supports Staff's conclusion that 5.30 percent Cost of LT Debt is a conservative and reasonable estimate.

Q. Did the Company overstate issuance costs, fail to address the current portion of LT Debt, or misstate the timing, amounts, maturity or coupon rates for planned debt issuances?

A. No. Cascade was conservative in its review of LT Debt. Exhibit Staff/806 adds more detail to the Company's filing, but corroborates Cascade's recommended 5.30 percent Cost of LT Debt. Cascade reviewed and agrees with Staff's analysis on this subject reflected in the response to DR 173.

Q. Are there discrepancies between the Company's filing and Staff's spreadsheet findings regarding Cost of LT Debt?

A. No. Both support a 5.30 percent Cost of LT Debt.

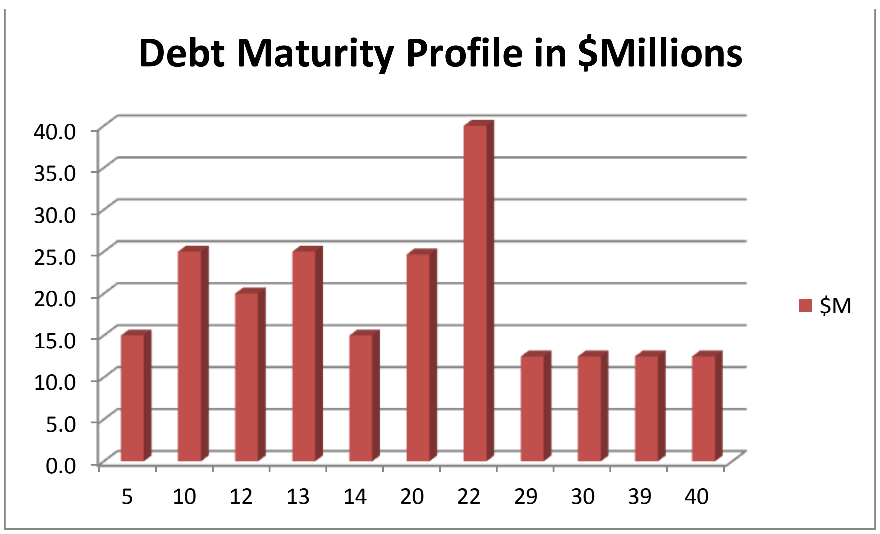
DEBT MATURITY PROFILE

Q. Has Staff reviewed the Company's debt maturities?

A. Yes. Staff has prepared Figure 4 below showing the Company's debt maturity profile. Staff makes no adjustment to the Company's maturities.

Figure 4

Years	$M
5	15.0
10	25.0
12	20.0
13	25.0
14	15.0
20	24.7
22	40.0
29	12.5
30	12.5
39	12.5
40	12.5



Years on the X axis are measured from the end of the test year.

ISSUE 4 – OVERALL RATE OF RETURN (ROR)

Q. In summary, are Staff's modeling results supportive of the Company's proposed 51 percent Equity / 49 percent LT Debt Capital Structure, 9.55 percent ROE and 5.30 percent Cost of LT Debt.?

A. Yes. This recommendation is based on Staff's modeling results and Staff's Risk Assessment in **CONFIDENTIAL** Exhibit Staff/808. Exhibit/808 also recommends the Commission consider several conditions in its Order.

Q. And you agree with the Company that these CoC findings are reasonably represented by a ROR of 7.47 percent

A. Yes.

Q. Does that conclude your opening testimony regarding Cost of Capital?

A. Yes.

ISSUE 5 – ALLOCATIONS

Q. How does the Company represent its follow through in compliance with Commission Order No. 07-221?

A. Cascade witness Marc Chiles testifies that the Company's allocated shared corporate costs and its allocated and assigned utility division costs do not exceed the costs that Cascade customers would otherwise have paid absent acquisition.[28] Cascade further represents that intercompany allocations provide necessary services at costs equal or lower than if Cascade had performed like services internally or contracted for the services with non-

[28] CNG/200 Chiles/2.

affiliated companies.[29] This testimony considers the reasonableness of approximately five and a half million dollars of Cascade's projected 2015 Administrative and General cost. This is about three and a half million dollars of Cascade's Oregon allocated activity and about one and a half million dollars of Oregon Capital Work Orders. It looks at what share of these and other costs was allocated by MDUR and affiliates to Cascade in Oregon, and whether there is good indication that these costs were deployed to deliver the benefits ratepayers are paying for.

Q. What types of services do these allocations address?

A. Among others, these services include: board and executive services, legal and accounting services, use of office facilities and equipment, customer billing and collection, accounts payable processing, information technology support and customer service support.[30]

Q. Under the Intercompany Administrative Services Agreement (IASA) what entity is responsible for record keeping?

A. The issuing party is responsible for record keeping and support of charges.[31]

Q. From your perspective has the maintenance of records, record support and reporting at the issuing party been conducive to timely response to data requests?

A. No. Substantial delays in returning data requests suggest that reporting within MDU Resources Group, Inc. (MDUR) may be more oriented to

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29 CNG/200 Chiles/5 at lines 8-12.

30 CNG/200, Chiles/8.

31 See CNG/200 Chiles/9 at lines 16-19

upwardly informing MDUR and its subsidiaries rather than Cascade Natural Gas Corporation (Cascade) operational and regulatory personnel.

Q. Are there principles or drivers for Cascade's cost allocations?

A. Yes. In a confidential exhibit and in 63 responses to Staff data requests, the Company described its Pricing Methodology.[32] In addition, Cascade files annual Affiliated Interest (AI) reports and annual results of operations with the Commission.

Q. Do MDUR annual or other reports filed with the SEC drill down to this level of detail?

A. No.

Q. In general, what was Staff's approach to reviewing Cascade allocations?

A. Staff common sized annual AI reports filed with the Commission under the umbrella of Docket No. RG 44 for the last three years. This highlighted various higher than proportional surrounding allocated costs and higher trending allocated costs. Staff then issued data requests asking for explanation of these values.

Q. How did Cascade respond to these data requests?

A. The Company indicated that there were errors in the compilation of annual AI reports over the past three years. By July 16, 2015, the Commission received replacement AI reports for each of calendar years 2012, 2013 and 2014.

Q. Did the replacement AI reports then conform to the Company's general rate case filing as addressed herein?

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32 CNG/204

A. Yes. In general, the costs are now like-proportional to other common sized similarly allocated costs. Assuming the corrections are accepted, the bases for some Staff concerns about specific cost center allocations are relieved.

Q. Are the Oregon Allocation Three Factor (3-Factor) percentages the same in the annual results of operation filings under the umbrella of Docket No. RG 36 for Retiree Medical Expenses and Officer Incentives as found in the replacement AI reports for other tracked cost centers?

A. Yes. However, Staff notes that the annual results of operations only break out those two categories of costs.

Q. In Docket UG 173, a Commission-initiated rate case for Cascade, Staff had concerns about intercorporate costs. Specifically, Staff was concerned about rate recovery of allocated costs that were that one-time expenses, costs that do not result in efficiency or labor savings, and costs that were they incurred as part of itemized Oregon operation costs would normally be excluded from consideration in a general rate case. Did you exclude such costs?

A. No. I anticipate that my rebuttal testimony will analyze inter-corporate allocated costs and exclude any costs that Oregon ratepayers are not responsible for.

Q. In UG 173 testimony, a Staff witness noted that inclusive of some one-time costs, the Oregon allocation factor was 22.70 percent in 2004, 22.94 percent in 2005, and 23.44 percent in 2006.[33] How does that compare to

[33] Staff/300, Dougherty/6.

the Company's proposed 3-Factor allocation for Oregon in the 2015 test year?

A. Cascade proposes a 3-Factor Oregon allocation for the 2015 test year in this general rate case of 24.3 percent or a multiplier for pertinent costs of 0.243. This compares with corrected recent allocations factors of 24.55 percent in 2013 and 24.53 percent in 2012.

Q. Does this testimony directly address executive compensation, various corporate stock awards, various director fees, and officer bonuses?

A. No. Other Staff witnesses have proposed adjustments to Cascade's rate request regarding usually excluded or partially-excluded costs such as Director and Officers (D&O) insurance, Supplemental Executive Retirement (SERP) plans, meals and entertainment, office refreshments and catering, gifts and awards, and memberships. I have not yet confirmed that the allocation of costs to Cascade for these categories was reasonable. Nor have I screened specific cost centers to confirm that the Oregon allocated costs inclusive of taxes in other states generate benefits in excess of like operations in Oregon.

Q. Do you expect that your rebuttal testimony will address the reasonableness of intercorporate and shared executive and facility costs allocated to Cascade not otherwise addressed by other Staff in Opening Testimony?

A. Yes.

ALLOCATION TERMINOLOGY AND METHODS

Q. How is the term "Brand" used by MDUR?

A. Brand is used herein to mean any one of the four companies within the MDU Utilities Group. These companies are Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company, and Montana Dakota Utilities Co.[34]

Q. When are costs allocated equally between Brands?

A. The equal allocation of costs to each brand is generally done for executives or senior management who are providing oversight and direction for all of the brands and where customer counts or other metrics don't necessarily have a bearing on how much time is dedicated to a Brand.[35]

Q. Where time is a factor in allocating costs, how is time capture accomplished?

A. The only group included in the MDU Resources Shared Service Pricing Methodology document that is allocating cost based on actual time is the Customer Relations department (Department 965). The majority of this group's cost allocation is based on the number of devices they support within the MDU Resources companies. The smaller cost allocation is based on project work. In these cases the department utilizes a software program called M-Pro to log projects and track the time spent on the project.

Q. How does MDUR use the term "Business Unit"?

[34] See the Company's response to Staff DR 224.

[35] See the Company's response to Staff DR 225.

A. The term "Business Unit" refers to departments within Cascade Natural Gas Corporation or any of the other utility group companies or MDU Resources within which costs are recorded. The terms "Functional Units" and "Departments" are synonymous with the term "Business Unit".

Q. What role do time studies have in allocations pertinent to Cascade?

A. Cascade does not receive allocations based on time studies. There are four departments within the Utility Operation Support group that base their cost allocations on time studies. Three of these departments are within the Information Technology and Communication group; Engineering Services, Communications, and Software Architect/Developer. According to the Company's Director of Information Technology & Communications, all of the time studies in these areas are specific to electric operations at Montana Dakota Utilities; and none of the costs in these areas are allocated to Cascade Natural Gas Corporation. The last department that allocates time based on time studies is the Procurement department. These studies are also specific to the electric business and none of the costs in this area is allocated based on time.

Q. Please describe the multipart allocation method used to divide costs A) across MDUR companies and Brands; B) between states, and C) across departments and business units.

A. Cascade's first step is determining whether the cost is specific to a Brand or if it is an allocable cost. If it is determined that it is an allocable cost then the cost is allocated using the appropriate method as described in the Company's response to Staff DR 182. The cross charges from MDU Resources, MDU, and Intermountain Gas are each recorded in a single account except for charges coming from Customer Service, Information Technology, or Office Services. These departments charge to several accounts. The departments and department numbers follow in Figure 5 below:

Figure 5 – Departments

MDUR Allocated Costs	4760500	**IT Allocated Costs**	
MDU Allocated Costs	4766000	Compliance Systems & Telecom	4767500
IGC Allocated Costs	4766200	Information Technology, Dir	4767600
		Communication	4767700
Customer Service Allocated Costs		Information Systems	4767800
Credit and Collections	4767000	Mobile Services Manager	4767900
Customer Services, Dir	4767100	Enterprise GIS	4763400
Meridian-Customer Service	4767200		
Customer Development/Programs	4767300	**Office Services Allocated Costs**	4768000
Scheduling	4767400	**Fleet**	4766100

Q. How are costs then allocated to operations in the Northwest?

A. Once the costs have been accumulated in their respective accounts, the costs are allocated to Oregon and Washington based upon the three factor allocation of **customers, employees, and plant**. The 3-Factor allocation is updated annually to reflect changes in each of the three factors.

Q. Has the Company mapped functional areas to departments assign costs in Cascade's Oregon Regulated Utility Operations over the last three calendar years showing amounts and percentages allocated to Oregon?

A. Yes, Cascade provided this detail in response to DRs 274 and 275.

Q. What was Cascade's last general rate case decided in Washington State?

A. The last general rate case in Washington was in Docket No. UG-060256. The order number settling it was 05, and it was entered on January 12, 2007.

Q. Did that Cascade rate case use the same 3-Factor allocation method as presented to the Commission in this rate case?

A. Yes, although Cascade updates the allocation percentage for Oregon each year based on the three factors.

Q. Are the cost drivers identified in Cascade's response to Staff DR 182 expanding upon the Company's confidential CNG/204 reasonable against other viable alternatives?

A. Staff continues to analyze the reasonableness of the cost drivers and allocation methods for each type of costs, reflective of where that cost is performed and the unit cost based on Cascade alone and aggregate volumes of service. I expect to address this issue in rebuttal testimony.

Q. Is Cascade's allocation manual updated completely to reflect dynamic conditions inclusive of all confidential factors addressed in response to DR 182, other Staff DR's and the Chiles exhibit described immediately above?

A. No, many of the cost allocation methods are guidelines that allow for exceptions. All the allocation factors, such as are found now in multiple parts of this rate case and in response to myriad date requests, should be coherently and completely compiled into a dependable component of Cascade's annual AI filing.

Q. As Cascade modifies operations and cost recognition, should the Cost Allocation Manual component of the Company's annual AI report be updated to show the current recognized cost drivers and cost allocation approaches, and describe each change in methodology from the prior year?

A. Yes, Staff asks the Commission to consider ordering Cascade to annually update its Cost Allocation Manual as an integral part of its annual AI filing with the Commission to include all pertinent currently recognized cost drivers and cost allocation methods.

Q. Some of this information is treated as confidential by the Company. Is that a concern?

A. No. Cascade, like other jurisdictional energy utilities can flag its annual AI report as confidential at the Company's discretion.

Q. You appear uncomfortable with the quality of reporting that the Commission has lately received and the apparent difficulty of Cascade operational and regulatory Staff to promptly and accurately identify and describe all Cascade cash flows, both in and out of the utility, from a Cascade operational perspective.

A. Yes.

Q. Do you make a distinction here between record keeping and reporting that is able to timely and accurately inform Cascade operational and regulatory employees and the Commission versus records retained

outside Cascade operations and reporting structured to inform management higher in the MDUR organization?

A. Yes. It may be that synergies are achieved by shared intercorporate resources. However, such efficiencies do not relieve Cascade of timely record access or retrieval and reporting responsibilities, and do not immunize either Cascade or MDUR of the fiduciary duty to keep the Commission timely and accurately informed in conformance with the terms of MDUR's acquisition of Cascade.[36]

Q. Have you a recommendation for the Commission in this regard?

A. Yes. I recommend that the Commission emphasize that future AI reports must be accurately and timely submitted. While I appreciate that Cascade has corrected prior errors, I believe it is unusual for the Commission to receive three years of replacement AI reporting amended to correct prior errors as we saw this July in RG 44, very shortly before Staff's opening testimony in a general rate case.

Q. Have you made a placeholder adjustment to be updated as you prepare rebuttal testimony?

A. Yes, my placeholder adjustment of $500,000 ($100,000 A&G expense and $400,000 plant rate base) is predicated on two concerns:

A: Administrative, Management Information and other Services that Oregon ratepayers are paying for, are not demonstrated as delivered ongoing

36 Provisions 1 to 3 of Commission Order No. 07-320 in Docket No. UM 1283 require that Cascade will maintain its own accounting accessible to the Commission at Cascade's Washington Headquarters and that Cascade will maintain its own financial statements, such materials accessible to the Commission in timely manner.

expected benefit to Cascade's Oregon regulated operations ratepayers; and

B: Costs associated with assets and projects that are substantially owned by MDU like those indicated by the Company's response to DR 282, as listed in Figure 6 may not be correctly allocated to Cascade and by Cascade to Oregon regulated gas utility ratepayers.

Figure 6 – Project Ownership

Project	Owner
FP-101472 - Work Management-GL Essentials	MDU
FP-101479 - Mobile Workforce Management System	MDU
FP-101481 - UG GPSLS PROJECT - SOFTWARE	MDU
FP-101510 - Gas Management System	MDU
FP-200028 - UG AUTO TEST CNG DIRECT	MDU
FP-200064 - Customer Self-Service Web-based	MDU
FP-200155 - UG GPSLS PROJECT - HARDWARE	MDU
FP-200352 - Customer Care & Billing System	MDU
FP-200378 - Mobile Workforce Management Direct	MDU
FP-200663 - GIS Enhancements	MDU
FP-301811 - SCADA Enhancements	MDU
FP-301813 - SCADA Enhancements	MDU
FP-302579 - PII - Personal Info Security	MDU
FP-302616 - Human Capital Management	MDU
FP-302621 - LV Customer Website	MDU
FP-101478 - AUTOMATED VEHICLE LOCATION SYS	MDU
FP-200661 - DATA CENTER/NETWORKING EQUIP	MDU
FP-200662 - PC SUPPORT EQUIPMENT	MDU
FP-306967 - District Office Access Control Sys	CNGC

Q. Are the benefits that normally accrue to a utility through asset ownership or the benefits associated with an "Asset Light" energy operations strategy all realized by Cascade Oregon ratepayers?[37]

[37] Staff continues to examine benefits and risks of low-collateral debt and various qualified asset pool sizes in conjunction with Cascade long-term debt.

A. Further investigation and analysis should clarify this issue in my rebuttal testimony.

Q. Did you examine Cascade quarterly dividends paid and additional paid in capital from 2008 to June of 2015?

A. Yes. Staff's examination of the amount, frequency and rate of change in these cash flows as provided by the Company in response to Staff DR 259 raised no issues requiring additional follow up at this time.

Q. The Company has explained in response to DR 272 that its review undertaken in responding to Staff DRs regarding allocations revealed a variety of errors in Cascade's updating of its 3-Factor Allocation Rates, and some data entry errors in preparation of earlier spreadsheets that were carried forward, in addition to other benign and logical explanations. Does Staff have high confidence that corrected filings are now accurate and reliable?

A. No. Staff received the last of the updated filings a week ago. This testimony is prepared prior to full verification of recently revised data and completion of further analysis of follow-up data requests.

CONCLUSION

Q. You have flagged a number of issues for Commission consideration to potentially address in its order. Do these issues all merit such heightened attention?

A. Yes. The issues flagged directly relate to the risks and costs that MDUR is incurring and what portion of those risks and costs are reasonable for

Cascade's Oregon ratepayers to bear. As much time has passed since the Company's last general rate case and because its employees participating in the last rate case have departed, Cascade may need more thorough guidance regarding the Commission's expectations than other jurisdictional energy utilities filing rate cases more frequently.

Q. Does that conclude your opening testimony?

A. Yes

CASE: UG 287
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

July 31, 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 287
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Staff Peer Screening

Exhibits in Support
of Opening Testimony

July 31, 2015

Gas and Water Utilities Screened by Staff

1	2	3	4	5	6	7	8	9	10
	Natural Gas		Utility Continuity Screen						
	UG 287	1	Sensitivity with AWK, MSEX, YORW						
#	Abbreviated Utility	Straw UG 287 CNG	UG 287 Staff	VL Corporate Name Gas Utility	NYS, NSDQ Ticker	SNL Key	IRS EIN	SEC File	VL Industry / Region
-	Avista	No	No	Avista Corporation (*For reference Purposes Only*)	AVA	4057075	91-0462470	1-3701	West
-	Cascade	No	No	Cascade Natural Gas Corp.	MDU	4057112	91-0599090	1-7196	West
1	AGL	Yes	No	AGL Resources, Inc.	GAS	4057108	58-2210952	1-14174	East
2	Atmos	Yes	No	Atmos Energy Corp.	ATO	4057157	75-1743247	1-10042	Central
3	Laclede	Yes	No	The Laclede Group, Inc.	LG	4002506	74-2976504	1-16681	Central
4	New Jersey	Yes	No	New Jersey Resources Corp.	NJR	4057128	22-2376465	1-8359	East
5	Nicor	No	No	Nicor, Inc.	GAS	N/A	N/A	N/A	Central
6	NiSource	Yes	No	NiSource Inc.	NI	4057051	35-2108964	1-16189	East
7	Northwest Natural	Yes	Yes	Northwest Natural Gas Company	NWN	4057132	93-0256722	1-15973	West
8	Piedmont	Yes	Yes	Piedmont Natural Gas Company, Inc.	PNY	4057136	56-0556998	1-6196	East
9	South Jersey	Yes	No	South Jersey Industries, Inc.	SJI	4057145	22-1901645	1-6364	East
10	Southwest Gas	Yes	No	Southwest Gas Corporation	SWX	4041957	88-0085720	1-7850	West
11	UGI	Yes	No	UGI Corporation	UGI	4057537	23-2668356	1-11071	East
12	WGL	Yes	No	WGL Holdings, Inc.	WGL	4007261	52-2210912	1-16163	East
13	American States	No	No	American States Water Company	AWR	N/A	95-4676679	1-14431	Water
14	American Water	No	Sensitivity	American Water Works Company, Inc.	AWK	N/A	51-0063696	1-34028	Water
15	Aqua America	No	No	Aqua America, Inc.	WTR	N/A	23-1702594	1-6659	Water
16	CA Water	No	No	California Water Service Group	CWT	N/A	77-0448994	1-13883	Water
17	CT Water	No	No	Connecticut Water Service, Inc.	CTWS	N/A	06-0739839	0-8084	Water
18	Consol Water	No	No	Consolidated Water Co. Ltd.	CWCO	N/A	98-0619652	0-25248	Water
19	Middlesex Water	No	Sensitivity	Middlesex Water Co.	MSEX	N/A	22-1114430	0-422	Water
20	SJW	No	No	SJW Corp.	SJW	N/A	77-0066628	1-8966	Water
21	York Water	No	Sensitivity	York Water Company (The)	YORW	N/A	23-1242500	1-34245	Water

Continued on Next Page

Staff Peer Screen

1	2	11	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
	Natural Gas								Either / Or									
	UG 287							SNL or VL	S&P	Moody's	10-K	VL		VL	VL	VL	No M&A	Bloomberg
				Yahoo Fin.	VL			No Div	Local LT	Local LT	≥ 80% U.S.	LT Debt	VL	Common	Preferred	Div. Growth	Activity	M&A
	Abbreviated	VL	Yahoo Fin.	Mkt Cap	Mkt Cap	Gas or Water U.	VL	Declines	Rating	Rating	Regulated	< 56%	LT Debt	Equity	Stock	Rate	in Last	Under 11%
#	Utility	Beta	Beta	$ Billions	$ Billions	w VL Beta < 1	ID No.	5 years	≥ BBB-	≥ Baa3	Revenues	of Capital	of Capital	of Capital	of Capital	> 0%	4 Years	of Mkt Cap
-	Avista	0.80	0.74	2.20	1.45919	-	9677	Pass	BBB	Baa2	92%	50.83%	53.97%	49.2%	0.0%	Pass	Pass	9%
-	Cascade	N/A	N/A	N/A	N/A	-	N/A	Pass	BBB+	none	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1	AGL	0.80	0.49	6.52	5.61151	Yes	785	Pass	BBB+	Baa1	71%	51.22%	60.90%	48.8%	0.0%	Pass	Fail	Nicor
2	Atmos	0.80	0.59	5.54	4.16406	Yes	802	Pass	A-	A2	59%	48.76%	54.17%	51.2%	0.0%	Pass	Pass	7%
3	Laclede	0.70	0.55	2.30	1.51572	Yes	5203	Pass	A-	(P)Baa1	84%	46.59%	48.55%	53.4%	0.0%	Pass	Fail	125%
4	New Jersey	0.80	0.78	2.78	1.87789	Yes	6359	Pass	A	(P)Aa2	25%	36.63%	55.30%	63.4%	0.0%	Pass	Pass	0%
5	Nicor	N/A	N/A	N/A	N/A	No	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Fail	100%
6	NiSource	0.85	0.45	14.17	10.80610	Yes	6188	Pass	BBB-	(P)Ba1	50%	56.33%	60.01%	43.7%	0.0%	Pass	Pass	0%
7	Northwest Natural	0.70	0.57	1.32	1.13701	Yes	6490	Pass	A+	(P)A3	96%	48.55%	54.73%	51.5%	0.0%	Pass	Pass	0%
8	Piedmont	0.80	0.64	3.04	2.54464	Yes	7094	Pass	A	A2	93%	49.71%	58.49%	50.3%	0.0%	Pass	Pass	Limited
9	South Jersey	0.80	0.95	1.92	1.75094	Yes	8281	Pass	BBB+	A2	61%	44.96%	57.09%	55.0%	0.0%	Pass	Pass	Limited
10	Southwest Gas	0.85	0.92	2.77	2.49448	Yes	8314	Pass	A-	A3	67%	49.22%	49.29%	50.8%	0.0%	Pass	Pass	0%
11	UGI	0.85	0.72	6.08	5.09874	Yes	9166	Pass	none	A2	13%	59.98%	60.74%	40.0%	0.0%	Pass	Fail	50%
12	WGL	0.75	0.90	2.73	2.03943	Yes	9668	Pass	A+	none	49%	28.69%	45.19%	69.8%	1.5%	Pass	Pass	Limited
13	American States	0.70	1.14	1.55	1.19210	Yes	8288	Pass	A+	A2	73%	42.24%	40.80%	57.8%	0.0%	Pass	Pass	0%
14	American Water	0.70	0.43	9.72	7.89559	Yes	98442	Pass	A-	Baa1	89%	53.87%	55.14%	46.1%	0.0%	Pass	Pass	Limited
15	Aqua America	0.70	0.76	4.71	4.32920	Yes	7056	Pass	none	none	98%	52.70%	52.09%	47.3%	0.0%	Pass	Pass	Limited
16	CA Water	0.70	1.09	1.18	1.10373	Yes	1574	Pass	none	none	97%	47.84%	44.93%	52.2%	0.0%	Pass	Pass	Limited
17	CT Water	0.65	0.36	0.40	0.36496	Yes	2274	Pass	A	none	94%	48.95%	47.89%	50.8%	0.2%	Pass	Pass	ME H2O
18	Consol Water	0.90	1.01	0.16	0.19377	Yes	9991	Pass	none	none	36%	3.73%	3.90%	96.3%	0.0%	Pass	Pass	0%
19	Middlesex Water	0.70	0.60	0.37	0.32694	Yes	5950	Pass	A-	none	88%	41.54%	46.56%	57.4%	1.1%	Pass	Pass	Limited
20	SJW	0.85	0.73	0.68	0.58225	Yes	7824	Pass	none	none	96%	55.00%	51.77%	45.0%	0.0%	Pass	Pass	0%
21	York Water	0.65	0.77	0.30	0.26720	Yes	16182	Pass	A-	none	100%	45.97%	45.40%	54.0%	0.0%	Pass	Pass	0%

CASE: UG 297
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Staff Three Stage DCF Modeling

Exhibits in Support
of Opening Testimony

July 31, 2015

Required ROE
Hamada Adjusted Results from Three Stage DCF Modeling

Model X: 3 Stage DCF - Dividend Growth						
X	**Composite Growth**	**5.02%**	**Historical Growth**	**5.35%**	**Blue Chip Growth**	**5.78%**
Staff Gas Peers	**8.62%**	Implied Average ROE	8.86%	Implied Average ROE	9.32%	Implied Average ROE
Sensitivity 1 w Water	8.19%		8.43%		8.76%	
Company Gas Peers	7.75%		8.07%		8.32%	

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value						
Y	**Composite Growth**	**5.02%**	**Historical Growth**	**5.35%**	**Blue Chip Growth**	**5.78%**
Staff Gas Peers	8.89%	Implied Average ROE	9.08%	Implied Average ROE	**9.51%**	Implied Average ROE
Sensitivity 1 w Water	8.41%		8.61%		8.86%	
Company Gas Peers	8.13%		8.32%		8.58%	

Values Shown Above Are NOT Yet Adjusted for Equity Flotation Costs

Staff Interpretation of ROE Modeling Results

Staff's Recommendations:	Based on Actual **51% Equity** Capital Structure				
Staff Finds that the Best Modeling Fit is Staff's Peer Group in Comparison with Staff Sensitivity and Straw VL Gas Groups.					
Staff Peer ROE Range from:	8.54%	to	9.43%	Inclusive of Hamada Adjustment	
Upward Equity Flotation Cost Adjustment	+	0.125%			
Range of Reasonable ROE's	**8.67%**	to	**9.55%**		
Midpoint		**9.11%**			
Cascade's Infrequent Rate Case Filings Are Consistent with the Upper End of Staff's Range of Reasonable ROE's					
Rating Agency Assessment in Staff Exhibit 808 also points to the Upper End of Staff's Range of Reasonable ROE's					
Staff Recommends that the Commission Consider Cascade's Requested 9.55 percent ROE as Within the Range of Reasonable ROE's.					

Note: Please see next pages for illustrations of Three Stage DCF calculations.
Staff work papers contain the spreadsheets for these models in larger print as well as sensitivities examined.

Staff Model X – Dividend Growth with Terminal Value as Perpetuity

5.02% Annual Growth Rate - Stage 3

Staff Model X

Dividend Growth with Terminal Value as Perpetuity

UG 287 CNG

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
								Initial Stage						Transition Stage				
1	AGL	1	**0.8**	8.6%	57.0%	(0.00)	(54.14)	1.96	2.04	2.15	2.26	2.40	2.54	2.66	2.79	2.92	3.05	3.19
2	Atmos	2	**0.8**	7.5%	72.4%	0.00	(51.51)	1.50	1.56	1.61	1.66	1.70	1.74	1.80	1.86	1.93	2.00	2.07
3	Laclede	3	**0.7**	8.8%	54.6%	0.00	(47.55)	1.76	1.84	1.95	2.06	2.20	2.34	2.46	2.58	2.71	2.84	2.98
4	New Jersey	4	**0.8**	9.2%	57.7%	0.00	(53.97)	0.86	0.92	1.10	1.32	1.76	2.20	2.54	2.92	3.34	3.81	4.33
6	NiSource	5	**0.85**	7.5%	73.1%	0.00	(37.68)	1.02	1.06	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.53
7	Northwest Natural	6	**0.7**	8.5%	56.9%	0.00	(45.56)	1.85	1.88	1.94	2.01	2.10	2.19	2.26	2.32	2.39	2.45	2.52
8	Piedmont	7	**0.8**	8.4%	58.1%	0.00	(31.89)	1.27	1.31	1.35	1.39	1.43	1.47	1.52	1.57	1.62	1.67	1.72
9	South Jersey	8	**0.8**	11.7%	38.2%	0.00	(58.46)	0.96	1.02	1.31	1.68	2.60	3.52	4.27	5.15	6.16	7.33	8.67
10	Southwest Gas	9	**0.85**	7.9%	68.1%	0.00	(53.39)	1.43	1.62	1.72	1.82	1.80	1.78	1.92	2.07	2.23	2.39	2.57
11	UGI	10	**0.85**	7.8%	72.6%	0.00	(48.62)	0.80	0.88	0.99	1.12	1.30	1.48	1.64	1.82	2.01	2.21	2.43
12	WGL	11	**0.75**	8.2%	58.7%	0.00	(41.15)	1.74	1.85	1.88	1.92	1.87	1.82	1.87	1.92	1.98	2.03	2.08
14	American Water	12	**0.7**	7.8%	70.2%	0.00	(47.86)	1.21	1.33	1.41	1.49	1.52	1.55	1.67	1.80	1.93	2.07	2.23
19	Middlesex Water	13	**0.7**	7.9%	64.5%	0.00	(20.66)	0.76	0.77	0.79	0.80	0.83	0.86	0.87	0.89	0.91	0.93	0.94
21	York Water	14	**0.65**	8.1%	65.3%	0.00	(20.40)	0.57	0.60	0.64	0.68	0.74	0.80	0.84	0.89	0.94	0.99	1.05
			AVG:	**8.4%**	**62.0%**	**0.00**												

Staff's Peer Utilities	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043 Terminal Value	2044 Div	2044 Perpetuity
	Final Stage																					
AGL	3.35	3.52	3.69	3.88	4.07	4.28	4.49	4.72	4.95	5.20	5.46	5.74	6.03	6.33	6.65	6.98	7.33	7.70	8.09	247.50	8.49	239.01
Atmos	2.17	2.28	2.39	2.51	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.10	4.31	4.53	4.75	4.99	5.24	230.00	5.51	224.49
Laclede	3.13	3.28	3.45	3.62	3.80	3.99	4.19	4.40	4.63	4.86	5.10	5.36	5.63	5.91	6.21	6.52	6.85	7.19	7.55	218.86	7.93	210.93
New Jersey	4.54	4.77	5.01	5.26	5.53	5.80	6.10	6.40	6.72	7.06	7.41	7.79	8.18	8.59	9.02	9.47	9.95	10.45	10.97	288.45	11.52	276.93
NiSource	1.61	1.69	1.77	1.86	1.96	2.05	2.16	2.27	2.38	2.50	2.62	2.76	2.89	3.04	3.19	3.35	3.52	3.70	3.88	170.05	4.08	165.97
Northwest Natural	2.65	2.78	2.92	3.07	3.22	3.38	3.55	3.73	3.92	4.11	4.32	4.54	4.76	5.00	5.25	5.52	5.79	6.08	6.39	202.22	6.71	195.51
Piedmont	1.81	1.90	1.99	2.09	2.20	2.31	2.43	2.55	2.67	2.81	2.95	3.10	3.25	3.42	3.59	3.77	3.96	4.16	4.37	141.52	4.58	136.94
South Jersey	9.11	9.56	10.04	10.55	11.08	11.63	12.22	12.83	13.48	14.15	14.86	15.61	16.39	17.21	18.08	18.99	19.94	20.94	21.99	370.21	23.10	347.12
Southwest Gas	2.70	2.84	2.98	3.13	3.28	3.45	3.62	3.80	3.99	4.20	4.41	4.63	4.86	5.10	5.36	5.63	5.91	6.21	6.52	246.90	6.85	240.06
UGI	2.56	2.68	2.82	2.96	3.11	3.27	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.83	5.07	5.33	5.60	5.88	6.17	237.23	6.48	230.75
WGL	2.19	2.30	2.41	2.54	2.66	2.80	2.94	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.56	4.79	5.03	5.29	178.50	5.55	172.95
American Water	2.34	2.45	2.58	2.71	2.84	2.99	3.14	3.29	3.46	3.63	3.81	4.01	4.21	4.42	4.64	4.87	5.12	5.37	5.64	222.20	5.93	216.27
Middlesex Water	0.99	1.04	1.09	1.15	1.20	1.26	1.33	1.40	1.47	1.54	1.62	1.70	1.78	1.87	1.97	2.06	2.17	2.28	2.39	90.53	2.51	88.02
York Water	1.10	1.15	1.21	1.27	1.34	1.40	1.47	1.55	1.63	1.71	1.79	1.88	1.98	2.08	2.18	2.29	2.41	2.53	2.65	94.52	2.79	91.73

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
								Initial Stage						Transition Stage				
1	AGL	1	**0.8**	8.8%	54.6%	0.00	(54.14)	2.04	2.15	2.26	2.40	2.54	2.66	2.79	2.92	3.05	3.19	3.35
2	Atmos	2	**0.8**	7.6%	70.6%	0.00	(51.51)	1.56	1.61	1.66	1.70	1.74	1.80	1.86	1.93	2.00	2.07	2.17
3	Laclede	3	**0.7**	9.0%	52.2%	0.00	(47.55)	1.84	1.95	2.06	2.20	2.34	2.46	2.58	2.71	2.84	2.98	3.13
4	New Jersey	4	**0.8**	9.5%	53.1%	0.00	(53.97)	0.92	1.10	1.32	1.76	2.20	2.54	2.92	3.34	3.81	4.33	4.54
6	NiSource	5	**0.85**	7.6%	71.1%	0.00	(37.68)	1.06	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.53	1.61
7	Northwest Natural	6	**0.7**	8.6%	55.1%	0.00	(45.56)	1.88	1.94	2.01	2.10	2.19	2.26	2.32	2.39	2.45	2.52	2.65
8	Piedmont	7	**0.8**	8.5%	56.3%	-	(31.89)	1.31	1.35	1.39	1.43	1.47	1.52	1.57	1.62	1.67	1.72	1.81
9	South Jersey	8	**0.8**	12.2%	32.9%	0.00	(58.46)	1.02	1.31	1.68	2.60	3.52	4.27	5.15	6.16	7.33	8.67	9.11
10	Southwest Gas	9	**0.85**	8.0%	65.6%	0.00	(53.39)	1.62	1.72	1.82	1.80	1.78	1.92	2.07	2.23	2.39	2.57	2.70
11	UGI	10	**0.85**	8.0%	69.2%	0.00	(48.62)	0.88	0.99	1.12	1.30	1.48	1.64	1.82	2.01	2.21	2.43	2.56
12	WGL	11	**0.75**	8.4%	57.2%	0.00	(41.15)	1.85	1.88	1.92	1.87	1.82	1.87	1.92	1.98	2.03	2.08	2.19
14	American Water	12	**0.7**	7.9%	67.7%	0.00	(47.86)	1.33	1.41	1.49	1.52	1.55	1.67	1.80	1.93	2.07	2.23	2.34
19	Middlesex Water	13	**0.7**	8.0%	63.0%	0.00	(20.66)	0.77	0.79	0.80	0.83	0.86	0.87	0.89	0.91	0.93	0.94	0.99
21	York Water	14	**0.65**	8.2%	62.7%	0.00	(20.40)	0.60	0.64	0.68	0.74	0.80	0.84	0.89	0.94	0.99	1.05	1.10
			AVG:	**8.6%**	**59.4%**	**0.00**												

Staff's Peer Utilities	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043 Terminal Value	2044 Div	2044 Perpetuity
	Final Stage																					
AGL	3.52	3.69	3.88	4.07	4.28	4.49	4.72	4.95	5.20	5.46	5.74	6.03	6.33	6.65	6.98	7.33	7.70	8.09	8.49	247.72	8.92	238.80
Atmos	2.28	2.39	2.51	2.64	2.77	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.10	4.31	4.53	4.75	4.99	5.24	5.51	230.79	5.78	225.01
Laclede	3.28	3.45	3.62	3.80	3.99	4.19	4.40	4.63	4.86	5.10	5.36	5.63	5.91	6.21	6.52	6.85	7.19	7.55	7.93	218.86	8.33	210.53
New Jersey	4.77	5.01	5.26	5.53	5.80	6.10	6.40	6.72	7.06	7.41	7.79	8.18	8.59	9.02	9.47	9.95	10.45	10.97	11.52	284.09	12.10	271.99
NiSource	1.69	1.77	1.86	1.96	2.05	2.16	2.27	2.38	2.50	2.62	2.76	2.89	3.04	3.19	3.35	3.52	3.70	3.88	4.08	170.36	4.28	166.08
Northwest Natural	2.78	2.92	3.07	3.22	3.38	3.55	3.73	3.92	4.11	4.32	4.54	4.76	5.00	5.25	5.52	5.79	6.08	6.39	6.71	203.24	7.05	196.20
Piedmont	1.90	1.99	2.09	2.20	2.31	2.43	2.55	2.67	2.81	2.95	3.10	3.25	3.42	3.59	3.77	3.96	4.16	4.37	4.58	142.26	4.81	137.45
South Jersey	9.56	10.04	10.55	11.08	11.63	12.22	12.83	13.48	14.15	14.86	15.61	16.39	17.21	18.08	18.99	19.94	20.94	21.99	23.10	361.25	24.25	337.00
Southwest Gas	2.84	2.98	3.13	3.28	3.45	3.62	3.80	3.99	4.20	4.41	4.63	4.86	5.10	5.36	5.63	5.91	6.21	6.52	6.85	246.59	7.19	239.39
UGI	2.68	2.82	2.96	3.11	3.27	3.43	3.60	3.78	3.97	4.17	4.38	4.60	4.83	5.07	5.33	5.60	5.88	6.17	6.48	235.34	6.81	228.53
WGL	2.30	2.41	2.54	2.66	2.80	2.94	3.08	3.24	3.40	3.57	3.75	3.94	4.14	4.35	4.56	4.79	5.03	5.29	5.55	179.96	5.83	174.13
American Water	2.45	2.58	2.71	2.84	2.99	3.14	3.29	3.46	3.63	3.81	4.01	4.21	4.42	4.64	4.87	5.12	5.37	5.64	5.93	221.88	6.23	215.66
Middlesex Water	1.04	1.09	1.15	1.20	1.26	1.33	1.40	1.47	1.54	1.62	1.70	1.78	1.87	1.97	2.06	2.17	2.28	2.39	2.51	91.14	2.64	88.50
York Water	1.15	1.21	1.27	1.34	1.40	1.47	1.55	1.63	1.71	1.79	1.88	1.98	2.08	2.18	2.29	2.41	2.53	2.65	2.79	94.37	2.93	91.44

Staff Peer Group UG 287

Average IRR of BOY & EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	Average 2015 – 2019 Dividend Growth Rates EOY	BOY	Average
7	Northwest Natural	6	**0.7**	8.5%	56.0%	3.9%	3.8%	3.9%
8	Piedmont	7	**0.8**	8.4%	57.2%	2.9%	3.0%	3.0%
			Group Average	**8.49%**	**56.6%**			

Staff Sensity 1 UG 287

Average IRR of BOY & EOY Cash Flows

Screen	Staff's Sensitivity 3 Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	Average 2015 – 2019 Dividend Growth Rates EOY	BOY	Average
7	Northwest Natural	6	**0.7**	8.5%	56.0%	3.9%	3.8%	3.9%
8	Piedmont	7	**0.8**	8.4%	57.2%	2.9%	3.0%	3.0%
14	American Water	12	**0.7**	7.8%	69.0%	3.9%	4.3%	4.1%
19	Middlesex Water	13	**0.7**	7.9%	63.8%	2.7%	2.7%	2.7%
21	York Water	14	**0.65**	8.1%	64.0%	7.4%	7.1%	7.3%
			Group Average	**8.18%**	**62.0%**			

CNG's Straw Peer Group UG 287

Average IRR of BOY & EOY Cash Flows

Screen	Company's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	Average 2015 – 2019 Dividend Growth Rates EOY	BOY	Average
1	AGL	1	**0.8**	8.7%	55.8%	5.7%	5.5%	5.6%
2	Atmos	2	**0.8**	7.5%	71.5%	2.8%	2.9%	2.8%
3	Laclede	3	**0.7**	8.9%	53.4%	6.2%	6.0%	6.1%
4	New Jersey	4	**0.8**	9.3%	55.4%	24.4%	23.3%	23.8%
6	NiSource	5	**0.85**	7.5%	72.1%	4.2%	4.2%	4.2%
7	Northwest Natural	6	**0.7**	8.5%	56.0%	3.9%	3.8%	3.9%
8	Piedmont	7	**0.8**	8.4%	57.2%	2.9%	3.0%	3.0%
9	South Jersey	8	**0.8**	11.9%	35.6%	36.3%	34.4%	35.4%
10	Southwest Gas	9	**0.85**	7.9%	66.9%	2.4%	2.8%	2.6%
11	UGI	10	**0.85**	7.9%	70.9%	13.8%	13.3%	13.6%
12	WGL	11	**0.75**	8.3%	57.9%	-0.4%	-0.1%	-0.3%
			Group Average	**8.64%**	**59.3%**			

Staff Model Y – EPS Growth to Determine a Sale Terminal Value

5.35% Annual Growth Rate - Stage 3

Staff Model Y EPS Growth to Determine a Sale Terminal Value

UG 287 CNG

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
								Initial Stage						Transition Stage				
1	AGL	1	0.8	8.8%	59.7%	(0.00)	(54.14)	1.96	2.04	2.15	2.26	2.40	2.54	2.66	2.79	2.92	3.05	3.19
			e					4.72	3.10	3.46	3.86	4.30	4.74	5.26	5.81	6.41	7.06	7.77
2	Atmos	2	ATO	7.9%	77.6%	0.00	(51.51)	1.50	1.56	1.61	1.66	1.70	1.74	1.80	1.87	1.93	2.00	2.07
			e					3.01	3.00	3.16	3.32	3.50	3.68	3.95	4.25	4.56	4.89	5.24
3	Laclede	3	LG	9.9%	71.1%	0.00	(47.55)	1.76	1.84	1.95	2.06	2.20	2.34	2.46	2.58	2.71	2.84	2.98
			e					2.66	3.15	3.47	3.82	4.20	4.58	4.95	5.34	5.75	6.19	6.66
4	New Jersey	4	NJR	11.0%	88.9%	0.00	(53.97)	0.86	0.92	1.10	1.32	1.76	2.20	2.54	2.92	3.34	3.81	4.33
			e					2.10	1.75	2.26	2.91	3.75	4.59	5.22	5.92	6.69	7.55	8.48
6	NiSource	5	NI	8.8%	90.8%	0.00	(37.68)	1.02	1.06	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.53
			e					1.69	1.85	2.02	2.20	2.40	2.60	2.87	3.17	3.50	3.85	4.22
7	Northwest Natural	6	NWN	9.6%	73.6%	0.00	(45.56)	1.85	1.88	1.94	2.01	2.10	2.19	2.26	2.32	2.39	2.45	2.52
			e					2.16	1.90	2.28	2.75	3.30	3.85	4.11	4.38	4.66	4.95	5.26
8	Piedmont	7	PNY	8.4%	57.6%	0.00	(31.89)	1.27	1.31	1.35	1.39	1.43	1.47	1.52	1.57	1.62	1.67	1.72
			e					1.84	1.85	1.93	2.01	2.10	2.19	2.28	2.37	2.46	2.56	2.66
9	South Jersey	8	SJI	14.1%	88.5%	0.00	(58.46)	0.96	1.02	1.31	1.68	2.60	3.52	4.28	5.15	6.17	7.35	8.69
			e					1.58	1.65	2.36	3.36	4.80	6.24	7.25	8.40	9.69	11.13	12.74
10	Southwest Gas	9	SWX	8.5%	76.0%	0.00	(53.39)	1.43	1.62	1.72	1.82	1.80	1.78	1.92	2.07	2.23	2.40	2.57
			e					3.01	3.15	3.41	3.69	4.00	4.31	4.58	4.87	5.18	5.50	5.83
11	UGI Corp	10	UGI	10.3%	108.4%	0.00	(48.62)	0.80	0.88	0.99	1.12	1.30	1.48	1.64	1.82	2.01	2.21	2.44
			e					1.92	1.95	2.38	2.91	3.55	4.19	4.80	5.48	6.23	7.07	7.99
12	WGL	11	WGL	8.4%	59.2%	0.00	(41.15)	1.74	1.85	1.88	1.92	1.87	1.82	1.87	1.92	1.98	2.03	2.09
			e					2.68	2.90	2.97	3.03	3.10	3.17	3.31	3.46	3.61	3.76	3.93
14	American Water	12	AWK	8.4%	78.2%	0.00	(47.86)	1.21	1.33	1.41	1.49	1.52	1.55	1.67	1.80	1.93	2.08	2.23
			e					2.39	2.60	2.74	2.89	3.05	3.21	3.46	3.74	4.02	4.33	4.66
19	Middlesex Water	13	MSEX	7.8%	62.7%	0.00	(20.66)	0.76	0.77	0.79	0.80	0.83	0.86	0.87	0.89	0.91	0.93	0.94
			e					1.13	1.15	1.17	1.18	1.20	1.22	1.28	1.34	1.41	1.48	1.56
21	York Water	14	YORW	8.5%	71.9%	0.00	(20.66)	0.57	0.60	0.64	0.68	0.74	0.80	0.84	0.89	0.94	0.99	1.05
			e					0.89	0.95	1.00	1.05	1.10	1.15	1.24	1.33	1.42	1.53	1.63
				9.3%	76.0%	0.00												

Screen	Staff's Peer Utilities	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043 Terminal Value	2044 Div	2044 Sale	2043
		Final Stage																						
1	AGL	3.36	3.54	3.73	3.93	4.14	4.36	4.60	4.84	5.10	5.37	5.66	5.96	6.28	6.62	6.97	7.35	7.74	8.15	8.59	275.24	9.05	266.19	
		8.18	8.62	9.08	9.57	10.08	10.62	11.19	11.79	12.42	13.08	13.78	14.52	15.30	16.11	16.98	17.88	18.84	19.85	20.91		22.03		23.21
2	Atmos	2.18	2.30	2.42	2.55	2.68	2.83	2.98	3.14	3.31	3.48	3.67	3.87	4.07	4.29	4.52	4.76	5.02	5.28	5.57	273.75	5.86	267.89	
		5.52	5.81	6.13	6.45	6.80	7.16	7.55	7.95	8.37	8.82	9.30	9.79	10.32	10.87	11.45	12.06	12.71	13.39	14.10		14.86		15.65
3	Laclede	3.14	3.31	3.48	3.67	3.87	4.07	4.29	4.52	4.76	5.02	5.29	5.57	5.87	6.18	6.51	6.86	7.23	7.61	8.02	363.95	8.45	355.50	
		7.01	7.39	7.78	8.20	8.64	9.10	9.59	10.10	10.64	11.21	11.81	12.44	13.11	13.81	14.55	15.33	16.15	17.01	17.92		18.88		19.89
4	New Jersey	4.57	4.81	5.07	5.34	5.63	5.93	6.24	6.58	6.93	7.30	7.69	8.10	8.54	8.99	9.47	9.98	10.51	11.08	11.67	663.68	12.29	651.38	
		8.94	9.42	9.92	10.45	11.01	11.60	12.22	12.87	13.56	14.29	15.05	15.86	16.71	17.60	18.54	19.53	20.58	21.68	22.84		24.06		25.35
6	NiSource	1.61	1.70	1.79	1.89	1.99	2.09	2.21	2.32	2.45	2.58	2.72	2.86	3.02	3.18	3.35	3.53	3.72	3.91	4.12	285.53	4.34	281.19	
		4.45	4.69	4.94	5.20	5.48	5.77	6.08	6.41	6.75	7.11	7.49	7.89	8.31	8.76	9.23	9.72	10.24	10.79	11.36		11.97		12.61
7	Northwest Natural	2.66	2.80	2.95	3.11	3.27	3.45	3.63	3.82	4.03	4.25	4.47	4.71	4.96	5.23	5.51	5.80	6.11	6.44	6.79	338.87	7.15	331.72	
		5.55	5.84	6.15	6.48	6.83	7.20	7.58	7.99	8.41	8.86	9.34	9.84	10.36	10.92	11.50	12.12	12.77	13.45	14.17		14.93		15.73
8	Piedmont	1.81	1.91	2.01	2.12	2.23	2.35	2.48	2.61	2.75	2.90	3.06	3.22	3.39	3.57	3.76	3.96	4.18	4.40	4.64	142.71	4.88	137.82	
		2.80	2.95	3.11	3.28	3.45	3.64	3.83	4.04	4.25	4.48	4.72	4.97	5.24	5.52	5.82	6.13	6.46	6.80	7.16		7.55		7.95
9	South Jersey	9.16	9.65	10.17	10.71	11.28	11.89	12.52	13.19	13.90	14.64	15.42	16.25	17.12	18.03	19.00	20.02	21.09	22.21	23.40	1,432.49	24.65	1,407.84	
		13.42	14.13	14.89	15.69	16.53	17.41	18.34	19.32	20.36	21.45	22.59	23.80	25.08	26.42	27.83	29.32	30.89	32.54	34.28		36.12		38.05
10	Southwest Gas	2.71	2.86	3.01	3.17	3.34	3.52	3.71	3.91	4.11	4.33	4.57	4.81	5.07	5.34	5.62	5.93	6.24	6.58	6.93	316.25	7.30	308.95	
		6.14	6.47	6.82	7.18	7.57	7.97	8.40	8.85	9.32	9.82	10.34	10.90	11.48	12.09	12.74	13.42	14.14	14.90	15.69		16.53		17.42
11	UGI Corp	2.57	2.71	2.85	3.00	3.16	3.33	3.51	3.70	3.90	4.11	4.32	4.56	4.80	5.06	5.33	5.61	5.91	6.23	6.56	611.13	6.91	604.22	
		8.41	8.86	9.34	9.84	10.36	10.92	11.50	12.12	12.77	13.45	14.17	14.93	15.73	16.57	17.45	18.39	19.37	20.41	21.50		22.65		23.86
12	WGL	2.20	2.31	2.44	2.57	2.71	2.85	3.00	3.16	3.33	3.51	3.70	3.90	4.11	4.33	4.56	4.80	5.06	5.33	5.61	185.96	5.91	180.05	
		4.14	4.36	4.59	4.84	5.09	5.37	5.65	5.96	6.27	6.61	6.96	7.34	7.73	8.14	8.58	9.04	9.52	10.03	10.57		11.13		11.73
14	American Water	2.35	2.47	2.61	2.74	2.89	3.05	3.21	3.38	3.56	3.75	3.95	4.16	4.39	4.62	4.87	5.13	5.40	5.69	6.00	284.97	6.32	278.65	
		4.91	5.17	5.45	5.74	6.04	6.37	6.71	7.07	7.44	7.84	8.26	8.70	9.17	9.66	10.18	10.72	11.30	11.90	12.54		13.21		13.91
19	Middlesex Water	0.99	1.05	1.10	1.16	1.22	1.29	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	87.62	2.67	84.95	
		1.64	1.73	1.82	1.92	2.02	2.13	2.24	2.36	2.49	2.62	2.76	2.91	3.06	3.23	3.40	3.58	3.77	3.97	4.19		4.41		4.65
21	York Water	1.10	1.16	1.22	1.29	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.68	2.82	116.29	2.97	113.32	
		1.72	1.81	1.91	2.01	2.12	2.23	2.35	2.48	2.61	2.75	2.90	3.05	3.22	3.39	3.57	3.76	3.96	4.18	4.40		4.63		4.88

UG 287 CNG

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
								Initial Stage						Transition Stage				
1	AGL	1	0.8	9.0%	57.2%	0.00	(54.14)	2.04	2.15	2.26	2.40	2.54	2.66	2.79	2.92	3.05	3.19	3.36
			e					4.72	3.10	3.46	3.86	4.30	4.74	5.26	5.81	6.41	7.06	7.77
2	Atmos	2	ATO	8.0%	75.7%	0.00	(51.51)	1.56	1.61	1.66	1.70	1.74	1.80	1.87	1.93	2.00	2.07	2.18
			e					3.01	3.00	3.16	3.32	3.50	3.68	3.95	4.25	4.56	4.89	5.24
3	Laclede	3	LG	10.1%	68.4%	0.00	(47.55)	1.84	1.95	2.06	2.20	2.34	2.46	2.58	2.71	2.84	2.98	3.14
			e					2.66	3.15	3.47	3.82	4.20	4.58	4.95	5.34	5.75	6.19	6.66
4	New Jersey	4	NJR	11.3%	83.8%	0.00	(53.97)	0.92	1.10	1.32	1.76	2.20	2.54	2.92	3.34	3.81	4.33	4.57
			e					2.10	1.75	2.26	2.91	3.75	4.59	5.22	5.92	6.69	7.55	8.48
6	NiSource	5	NI	8.9%	88.7%	0.00	(37.68)	1.06	1.10	1.15	1.20	1.25	1.30	1.36	1.41	1.47	1.53	1.61
			e					1.69	1.85	2.02	2.20	2.40	2.60	2.87	3.17	3.50	3.85	4.22
7	Northwest Natural	6	NWN	9.8%	71.4%	0.00	(45.56)	1.88	1.94	2.01	2.10	2.19	2.26	2.32	2.39	2.45	2.52	2.66
			e					2.16	1.90	2.28	2.75	3.30	3.85	4.11	4.38	4.66	4.95	5.26
8	Piedmont	7	PNY	8.6%	55.6%	0.00	(31.89)	1.31	1.35	1.39	1.43	1.47	1.52	1.57	1.62	1.67	1.72	1.81
			e					1.84	1.85	1.93	2.01	2.10	2.19	2.28	2.37	2.46	2.56	2.66
9	South Jersey	8	SJI	14.6%	80.6%	0.00	(58.46)	1.02	1.31	1.68	2.60	3.52	4.28	5.15	6.17	7.35	8.69	9.16
			e					1.58	1.65	2.36	3.36	4.80	6.24	7.25	8.40	9.69	11.13	12.74
10	Southwest Gas	9	SWX	8.6%	73.4%	0.00	(53.39)	1.62	1.72	1.82	1.80	1.78	1.92	2.07	2.23	2.40	2.57	2.71
			e					3.01	3.15	3.41	3.69	4.00	4.31	4.58	4.87	5.18	5.50	5.83
11	UGI Corp	10	UGI	10.4%	104.8%	0.00	(48.62)	0.88	0.99	1.12	1.30	1.48	1.64	1.82	2.01	2.21	2.44	2.57
			e					1.92	1.95	2.38	2.91	3.55	4.19	4.80	5.48	6.23	7.07	7.99
12	WGL	11	WGL	8.5%	76.0%	0.00	(41.15)	1.85	1.88	1.92	1.87	1.82	1.87	1.92	1.98	2.03	2.09	2.20
			e					2.68	2.90	2.97	3.03	3.10	3.17	3.31	3.46	3.61	3.76	3.93
14	American Water	12	AWK	8.5%	77.9%	0.00	(47.86)	1.33	1.41	1.49	1.52	1.55	1.67	1.80	1.93	2.08	2.23	2.35
			e					2.39	2.60	2.74	2.89	3.05	3.21	3.46	3.74	4.02	4.33	4.66
19	Middlesex Water	13	MSEX	8.0%	78.1%	0.00	(20.66)	0.77	0.79	0.80	0.83	0.86	0.87	0.89	0.91	0.93	0.94	0.99
			e					1.13	1.15	1.17	1.18	1.20	1.22	1.28	1.34	1.41	1.48	1.56
21	York Water	14	YORW	8.7%	79.0%	0.00	(20.66)	0.60	0.64	0.68	0.74	0.80	0.84	0.89	0.94	0.99	1.05	1.10
			e					0.89	0.95	1.00	1.05	1.10	1.15	1.24	1.33	1.42	1.53	1.63
				9.5%	76.5%	0.00												

Screen	Staff's Peer Utilities	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2043 Terminal Value	2044 Div	2044 Perpetuity	
		Final Stage																						
1	AGL	3.54	3.73	3.93	4.14	4.36	4.60	4.84	5.10	5.37	5.66	5.96	6.28	6.62	6.97	7.35	7.74	8.15	8.59	9.05	275.73	9.53	266.19	
		8.18	8.62	9.08	9.57	10.08	10.62	11.19	11.79	12.42	13.08	13.78	14.52	15.30	16.11	16.98	17.88	18.84	19.85	20.91		22.03		23.21
2	Atmos	2.30	2.42	2.55	2.68	2.83	2.98	3.14	3.31	3.48	3.67	3.87	4.07	4.29	4.52	4.76	5.02	5.28	5.57	5.86	274.07	6.18	267.89	
		5.52	5.81	6.13	6.45	6.80	7.16	7.55	7.95	8.37	8.82	9.30	9.79	10.32	10.87	11.45	12.06	12.71	13.39	14.10		14.86		15.65
3	Laclede	3.31	3.48	3.67	3.87	4.07	4.29	4.52	4.76	5.02	5.29	5.57	5.87	6.18	6.51	6.86	7.23	7.61	8.02	8.45	364.40	8.90	355.50	
		7.01	7.39	7.78	8.20	8.64	9.10	9.59	10.10	10.64	11.21	11.81	12.44	13.11	13.81	14.55	15.33	16.15	17.01	17.92		18.88		19.89
4	New Jersey	4.81	5.07	5.34	5.63	5.93	6.24	6.58	6.93	7.30	7.69	8.10	8.54	8.99	9.47	9.98	10.51	11.08	11.67	12.29	664.34	12.95	651.38	
		8.94	9.42	9.92	10.45	11.01	11.60	12.22	12.87	13.56	14.29	15.05	15.86	16.71	17.60	18.54	19.53	20.58	21.68	22.84		24.06		25.35
6	NiSource	1.70	1.79	1.89	1.99	2.09	2.21	2.32	2.45	2.58	2.72	2.86	3.02	3.18	3.35	3.53	3.72	3.91	4.12	4.34	285.76	4.58	281.19	
		4.45	4.69	4.94	5.20	5.48	5.77	6.08	6.41	6.75	7.11	7.49	7.89	8.31	8.76	9.23	9.72	10.24	10.79	11.36		11.97		12.61
7	Northwest Natural	2.80	2.95	3.11	3.27	3.45	3.63	3.82	4.03	4.25	4.47	4.71	4.96	5.23	5.51	5.80	6.11	6.44	6.79	7.15	339.25	7.53	331.72	
		5.55	5.84	6.15	6.48	6.83	7.20	7.58	7.99	8.41	8.86	9.34	9.84	10.36	10.92	11.50	12.12	12.77	13.45	14.17		14.93		15.73
8	Piedmont	1.91	2.01	2.12	2.23	2.35	2.48	2.61	2.75	2.90	3.06	3.22	3.39	3.57	3.76	3.96	4.18	4.40	4.64	4.88	142.97	5.14	137.82	
		2.80	2.95	3.11	3.28	3.45	3.64	3.83	4.04	4.25	4.48	4.72	4.97	5.24	5.52	5.82	6.13	6.46	6.80	7.16		7.55		7.95
9	South Jersey	9.65	10.17	10.71	11.28	11.89	12.52	13.19	13.90	14.64	15.42	16.25	17.12	18.03	19.00	20.02	21.09	22.21	23.40	24.65	1,433.81	25.97	1,407.84	
		13.42	14.13	14.89	15.69	16.53	17.41	18.34	19.32	20.36	21.45	22.59	23.80	25.08	26.42	27.83	29.32	30.89	32.54	34.28		36.12		38.05
10	Southwest Gas	2.86	3.01	3.17	3.34	3.52	3.71	3.91	4.11	4.33	4.57	4.81	5.07	5.34	5.62	5.93	6.24	6.58	6.93	7.30	316.64	7.69	308.95	
		6.14	6.47	6.82	7.18	7.57	7.97	8.40	8.85	9.32	9.82	10.34	10.90	11.48	12.09	12.74	13.42	14.14	14.90	15.69		16.53		17.42
11	UGI Corp	2.71	2.85	3.00	3.16	3.33	3.51	3.70	3.90	4.11	4.32	4.56	4.80	5.06	5.33	5.61	5.91	6.23	6.56	6.91	611.50	7.28	604.22	
		8.41	8.86	9.34	9.84	10.36	10.92	11.50	12.12	12.77	13.45	14.17	14.93	15.73	16.57	17.45	18.39	19.37	20.41	21.50		22.65		23.86
12	WGL	2.31	2.44	2.57	2.71	2.85	3.00	3.16	3.33	3.51	3.70	3.90	4.11	4.33	4.56	4.80	5.06	5.33	5.61	5.91	186.28	6.23	180.05	
		4.14	4.36	4.59	4.84	5.09	5.37	5.65	5.96	6.27	6.61	6.96	7.34	7.73	8.14	8.58	9.04	9.52	10.03	10.57		11.13		11.73
14	American Water	2.47	2.61	2.74	2.89	3.05	3.21	3.38	3.56	3.75	3.95	4.16	4.39	4.62	4.87	5.13	5.40	5.69	6.00	6.32	285.30	6.66	278.65	
		4.91	5.17	5.45	5.74	6.04	6.37	6.71	7.07	7.44	7.84	8.26	8.70	9.17	9.66	10.18	10.72	11.30	11.90	12.54		13.21		13.91
19	Middlesex Water	1.05	1.10	1.16	1.22	1.29	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.67	87.77	2.82	84.95	
		1.64	1.73	1.82	1.92	2.02	2.13	2.24	2.36	2.49	2.62	2.76	2.91	3.06	3.23	3.40	3.58	3.77	3.97	4.19		4.41		4.65
21	York Water	1.16	1.22	1.29	1.36	1.43	1.51	1.59	1.67	1.76	1.86	1.96	2.06	2.17	2.29	2.41	2.54	2.68	2.82	2.97	116.45	3.13	113.32	
		1.72	1.81	1.91	2.01	2.12	2.23	2.35	2.48	2.61	2.75	2.90	3.05	3.22	3.39	3.57	3.76	3.96	4.18	4.40		4.63		4.88

Staff Peer Group UG XXX

Average IRR of BOY & EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	Average 2015 – 2019 Dividend Growth Rates EOY	BOY	Average
7	Northwest Natural	6	NWN	9.7%	72.5%	3.9%	3.8%	3.9%
8	Piedmont	7	PNY	8.5%	56.6%	2.9%	3.0%	3.0%
		Group Average		9.10%	64.6%			

Staff Sensity 1 UG XXX

Average IRR of BOY & EOY Cash Flows

Screen	Staff's Sensitivity 3 Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	Average 2015 – 2019 Dividend Growth Rates EOY	BOY	Average
7	Northwest Natural	6	NWN	9.7%	72.5%	3.9%	3.8%	3.9%
8	Piedmont	7	PNY	8.5%	56.6%	2.9%	3.0%	3.0%
14	American Water	12	AWK	8.5%	78.0%	3.9%	4.3%	4.1%
19	Middlesex Water	13	MSEX	7.9%	70.4%	2.7%	2.7%	2.7%
21	York Water	14	YORW	8.6%	75.4%	7.4%	7.2%	7.3%
		Group Average		8.63%	70.6%			

CNG Straw Peer Group UG 287

Average IRR of BOY & EOY Cash Flows

Screen	Company's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	Average 2015 – 2019 Dividend Growth Rates EOY	BOY	Average
1	AGL	1	0.8	8.9%	58.5%	5.7%	5.5%	5.6%
2	Atmos	2	ATO	8.0%	76.7%	2.8%	2.9%	2.8%
3	Laclede	3	LG	10.0%	69.8%	6.2%	6.0%	6.1%
4	New Jersey	4	NJR	11.2%	86.4%	24.4%	23.3%	23.8%
6	NiSource	5	NI	8.9%	89.8%	4.2%	4.2%	4.2%
7	Northwest Natural	6	NWN	9.7%	72.5%	3.9%	3.8%	3.9%
8	Piedmont	7	PNY	8.5%	56.6%	2.9%	3.0%	3.0%
9	South Jersey	8	SJI	14.4%	84.6%	36.3%	34.5%	35.4%
10	Southwest Gas	9	SWX	8.6%	74.7%	2.4%	2.8%	2.6%
11	UGI Corp	10	UGI	10.3%	106.6%	13.8%	13.3%	13.6%
12	WGL	11	WGL	8.4%	67.6%	-0.4%	-0.1%	-0.3%
			Group Average	9.71%	76.7%			

CASE: UG 287
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 804

Staff Synthetic Forward Curve TIPS Analysis

Exhibits in Support
of Opening Testimony

July 31, 2015

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

Yr. End Mo.-Yr.	Years	Individually Implied Price Levels 5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Implied Forward Curve/Price Level 5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Implied 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	1.98	2.01	2.05	
2006-02	1.96	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	2.67	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	2.38	
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	1.60	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	1.57	1.69
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	0.88	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	0.95	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	4.18	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	2.87	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.86	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	2.36	
2008	1.30	1.63	1.77	2.18	
2009	1.06	1.32	1.66	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 287
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 805

Staff Historical GDP Analysis with BEA Data

Exhibits in Support
of Opening Testimony

July 31, 2015

Bureau of Economic Analysis (BEA)

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

Staff Accessed 1/30/15

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

Annual

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)

1980 through 2014 Q4 — Average 5.37% Nominal; Average 2.74% Real

Quarter	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#			
1947q1	243.1	1,934.5	1	1	8.783381	1980
1947q2	246.3	1,932.3	2	2	8.762896	
1947q3	250.1	1,930.3	3	3	8.761378	
1947q4	260.3	1,960.7	4	4	8.779742	
1948q1	266.2	1,989.5	5	5	8.800219	1981
1948q2	272.9	2,021.9	6	6	8.792899	
1948q3	279.5	2,033.2	7	7	8.804310	
1948q4	280.7	2,035.3	8	8	8.792565	
1949q1	275.4	2,007.5	9	9	8.775704	1982
1949q2	271.7	2,000.8	10	10	8.781125	
1949q3	273.3	2,022.8	11	11	8.777525	
1949q4	271.0	2,004.7	12	12	8.778495	
1950q1	281.2	2,084.6	13	13	8.791516	1983
1950q2	290.7	2,147.6	14	14	8.814078	
1950q3	308.5	2,230.4	15	15	8.833463	
1950q4	320.3	2,273.4	16	16	8.853880	
1951q1	336.4	2,304.5	17	17	8.873552	1984
1951q2	344.5	2,344.5	18	18	8.890961	
1951q3	351.8	2,392.8	19	19	8.900753	
1951q4	356.6	2,398.1	20	20	8.908695	
1952q1	360.2	2,423.5	21	21	8.918583	1985
1952q2	361.4	2,428.5	22	22	8.927699	
1952q3	368.1	2,446.1	23	23	8.943140	
1952q4	381.2	2,526.4	24	24	8.950611	
1953q1	388.5	2,573.4	25	25	8.959838	1986
1953q2	392.3	2,593.5	26	26	8.964414	
1953q3	391.7	2,578.9	27	27	8.974441	
1953q4	386.5	2,539.8	28	28	8.979606	
1954q1	385.9	2,528.0	29	29	8.986572	1987
1954q2	386.7	2,530.7	30	30	8.997729	
1954q3	391.6	2,559.4	31	31	9.006754	
1954q4	400.3	2,609.3	32	32	9.023131	
1955q1	413.8	2,683.8	33	33	9.028735	1988
1955q2	422.2	2,727.5	34	34	9.041863	
1955q3	430.9	2,764.1	35	35	9.047621	
1955q4	437.8	2,780.8	36	36	9.060784	
1956q1	440.5	2,770.0	37	37	9.070814	1989
1956q2	446.8	2,792.9	38	38	9.078647	
1956q3	452.0	2,790.6	39	39	9.086080	
1956q4	461.3	2,836.2	40	40	9.088195	
1957q1	470.6	2,854.5	41	41	9.099085	1990
1957q2	472.8	2,848.2	42	42	9.102944	
1957q3	480.3	2,875.9	43	43	9.103189	
1957q4	475.7	2,846.4	44	44	9.094638	
1958q1	468.4	2,772.7	45	45	9.089934	1991
1958q2	472.8	2,790.6	46	46	9.097664	
1958q3	486.7	2,855.5	47	47	9.102454	
1958q4	500.4	2,922.3	48	48	9.106800	
1959q1	511.1	2,976.6	49	49	9.118554	1992
1959q2	524.2	3,049.0	50	50	9.129510	
1959q3	525.2	3,043.1	51	51	9.139188	
1959q4	529.3	3,055.1	52	52	9.149156	
1960q1	543.3	3,123.2	53	53	9.151026	1993
1960q2	542.7	3,111.3	54	54	9.156950	
1960q3	546.0	3,119.1	55	55	9.161812	
1960q4	541.1	3,081.3	56	56	9.175076	
1961q1	545.9	3,102.3	57	57	9.184838	1994
1961q2	557.4	3,159.9	58	58	9.198409	
1961q3	568.2	3,212.6	59	59	9.204292	
1961q4	581.6	3,277.7	60	60	9.215577	
1962q1	595.2	3,336.8	61	61	9.218993	1995
1962q2	602.6	3,372.7	62	62	9.222476	
1962q3	609.6	3,404.8	63	63	9.231005	
1962q4	613.1	3,418.0	64	64	9.238072	
1963q1	622.7	3,456.1	65	65	9.244616	1996
1963q2	631.8	3,501.1	66	66	9.261927	
1963q3	645.0	3,569.5	67	67	9.271134	
1963q4	654.8	3,595.0	68	68	9.281647	
1964q1	671.1	3,672.7	69	69	9.289235	1997
1964q2	680.8	3,716.4	70	70	9.304213	
1964q3	692.8	3,766.9	71	71	9.316860	
1964q4	698.4	3,780.2	72	72	9.324588	
1965q1	719.2	3,873.5	73	73	9.334432	1998
1965q2	732.4	3,926.4	74	74	9.344084	
1965q3	750.2	4,006.2	75	75	9.357087	
1965q4	773.1	4,100.6	76	76	9.373369	
1966q1	797.3	4,201.9	77	77	9.381323	1999
1966q2	807.2	4,219.1	78	78	9.389532	
1966q3	820.8	4,249.2	79	79	9.402043	
1966q4	834.9	4,285.6	80	80	9.419247	
1967q1	846.0	4,324.9	81	81	9.422148	2000
1967q2	851.1	4,328.7	82	82	9.440857	
1967q3	866.6	4,366.1	83	83	9.442063	
1967q4	883.2	4,401.2	84	84	9.447726	
1968q1	911.1	4,490.6	85	85	9.444883	2001
1968q2	936.3	4,566.4	86	86	9.450168	
1968q3	952.3	4,599.3	87	87	9.447000	
1968q4	970.1	4,619.8	88	88	9.449775	
1969q1	995.4	4,691.6	89	89	9.458941	2002
1969q2	1,011.4	4,706.7	90	90	9.464440	
1969q3	1,032.0	4,736.1	91	91	9.469299	
1969q4	1,040.7	4,715.5	92	92	9.469932	
1970q1	1,053.5	4,707.1	93	93	9.475102	2003
1970q2	1,070.1	4,715.4	94	94	9.484337	
1970q3	1,088.5	4,757.2	95	95	9.500948	
1970q4	1,091.5	4,708.3	96	96	9.512569	
1971q1	1,137.8	4,834.3	97	97	9.518303	2004
1971q2	1,159.4	4,861.9	98	98	9.525604	
1971q3	1,180.3	4,900.0	99	99	9.534653	
1971q4	1,193.6	4,914.3	100	100	9.543263	
1972q1	1,233.8	5,002.4	101	101	9.553866	2005
1972q2	1,270.1	5,118.3	102	102	9.559073	
1972q3	1,293.8	5,165.4	103	103	9.567441	
1972q4	1,332.0	5,251.2	104	104	9.573135	
1973q1	1,380.7	5,380.5	105	105	9.585078	2006
1973q2	1,417.6	5,441.5	106	106	9.588064	
1973q3	1,436.8	5,411.9	107	107	9.588955	
1973q4	1,479.1	5,462.4	108	108	9.596752	
1974q1	1,494.7	5,417.0	109	109	9.597370	2007
1974q2	1,534.2	5,431.3	110	110	9.604994	
1974q3	1,563.4	5,378.7	111	111	9.611697	
1974q4	1,603.0	5,357.2	112	112	9.615259	
1975q1	1,619.6	5,292.4	113	113	9.608412	2008
1975q2	1,656.4	5,333.2	114	114	9.613362	
1975q3	1,713.8	5,421.4	115	115	9.608553	
1975q4	1,765.9	5,494.4	116	116	9.587200	
1976q1	1,824.5	5,618.5	117	117	9.573246	2009
1976q2	1,856.9	5,661.0	118	118	9.571895	
1976q3	1,890.5	5,689.8	119	119	9.575157	
1976q4	1,938.4	5,732.5	120	120	9.584789	
1977q1	1,992.5	5,799.2	121	121	9.589106	2010
1977q2	2,060.2	5,913.0	122	122	9.598720	
1977q3	2,122.4	6,017.6	123	123	9.605452	
1977q4	2,168.7	6,018.2	124	124	9.611731	
1978q1	2,208.7	6,039.2	125	125	9.607861	2011
1978q2	2,336.6	6,274.0	126	126	9.615112	
1978q3	2,398.9	6,335.3	127	127	9.617211	
1978q4	2,482.2	6,420.3	128	128	9.628412	
1979q1	2,531.6	6,433.0	129	129	9.633973	2012
1979q2	2,595.9	6,440.8	130	130	9.638004	
1979q3	2,670.4	6,487.1	131	131	9.644153	
1979q4	2,730.7	6,503.9	132	132	9.644309	
1980q1	**2,796.5**	**6,524.9**	133	133	9.651070	2013
1980q2	2,799.9	6,392.6	134	134	9.655449	
1980q3	2,860.0	6,382.9	135	135	9.666492	
1980q4	**2,993.5**	**6,501.2**	136	136	9.675093	
1981q1	3,131.8	6,635.7	137	137	9.669770	2014
1981q2	3,167.3	6,587.3	138	138	9.680994	
1981q3	3,261.2	6,662.9	139	139	9.693112	
1981q4	3,283.5	6,585.1	140	140	9.699632	
1982q1	3,273.8	6,475.0	141			

OLS Regression

Annualized Real LN GPD Q

2.87%

Regression Statistics

Multiple R	0.988570992
R Square	0.977272606
Adjusted F	0.977107915
Standard I	0.044086238
Observatic	140

ANOVA

	df	SS	MS	F	Significance F
Regressio	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 Variabl	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.

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
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	##########	12,359.1	213
2000q2	##########	12,592.5	214
2000q3	##########	12,607.7	215
2000q4	##########	12,679.3	216
2001q1	##########	12,643.3	217
2001q2	##########	12,710.3	218
2001q3	##########	12,670.1	219
2001q4	##########	12,705.3	220
2002q1	##########	12,822.3	221
2002q2	##########	12,893.0	222
2002q3	##########	12,955.8	223
2002q4	##########	12,964.0	224
2003q1	##########	13,031.2	225
2003q2	##########	13,152.1	226
2003q3	##########	13,372.4	227
2003q4	##########	13,528.7	228
2004q1	##########	13,606.5	229
2004q2	##########	13,706.2	230
2004q3	##########	13,830.8	231
2004q4	##########	13,950.4	232
2005q1	##########	14,099.1	233
2005q2	##########	14,172.7	234
2005q3	##########	14,291.8	235
2005q4	##########	14,373.4	236
2006q1	##########	14,546.1	237
2006q2	##########	14,589.6	238
2006q3	##########	14,602.6	239
2006q4	##########	14,716.9	240
2007q1	##########	14,726.0	241
2007q2	##########	14,838.7	242
2007q3	##########	14,938.5	243
2007q4	##########	14,991.8	244
2008q1	##########	14,889.5	245
2008q2	##########	14,963.4	246
2008q3	##########	14,891.6	247
2008q4	##########	14,577.0	248
2009q1	##########	14,375.0	249
2009q2	##########	14,355.6	250
2009q3	##########	14,402.5	251
2009q4	##########	14,541.9	252
2010q1	##########	14,604.8	253
2010q2	##########	14,745.9	254
2010q3	##########	14,845.5	255
2010q4	##########	14,939.0	256
2011q1	##########	14,881.3	257
2011q2	##########	14,989.6	258
2011q3	##########	15,021.1	259
2011q4	##########	15,190.3	260
2012q1	##########	15,275.0	261
2012q2	##########	15,336.7	262
2012q3	##########	15,431.3	263
2012q4	##########	15,433.7	264
2013q1	##########	15,538.4	265
2013q2	##########	15,606.6	266
2013q3	##########	15,779.9	267
2013q4	##########	15,916.2	268
2014q1	##########	15,831.7	269
2014q2	##########	16,010.4	270
2014q3	##########	16,205.6	271
2014q4	##########	16,311.6	272

CASE: UG 287
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 806

Cost of Long-Term Debt

Exhibits in Support
of Opening Testimony

July 31, 2015

STAFF EXHIBIT 806

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ORDER NO. 15-094 IN UG 287

CASE: UG 287
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 807

VL Gas and Water Industry Profiles

Exhibits in Support of Opening Testimony

July 31, 2015

INDUSTRY TIMELINESS: 15 (of 96)

Prices of a number of equities in *Value Line's* Natural Gas Utility Industry have been range-bound thus far in 2015. This trading behavior is not unusual, however, since those issues tend to be desired by buy-and-hold investors (such as retirees) because of their stable, healthy income streams. Of course, this does not mean that the group is invulnerable to large price fluctuations in the market, which appears to be happening more often these days. Indeed, investors are concerned, among other things, about the timing of a meaningful recovery in oil pricing and ISIS terrorist actions in the Middle East.

Weather Conditions

Weather is a factor that affects the demand for natural gas, particularly from small commercial businesses and consumers. Not surprisingly, earnings for utilities are susceptible to seasonal temperature patterns, with consumption normally at its peak during the winter heating months. Unseasonably warm or cold weather can cause substantial volatility in quarterly operating results. But some companies strive to counteract this exposure through temperature-adjusted rate mechanisms, which are available in many states. Therefore, investors interested in utilities with more-stable profits from year to year are advised to look for companies that are able to hedge this risk.

Business Structure

A number of these utilities have to 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. 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 may place greater emphasis on cost cutting and nonregulated businesses (which include pipelines and energy marketing & trading).

Appealing Dividends

The main attraction 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 3.2%, significantly higher than the *Value Line* median of 2.1%. Standouts include *AGL Resources, Northwest Natural Gas, Laclede Group, Piedmont Natural Gas,* and *South Jersey Industries.* When the financial markets exhibit greater volatility, which seems to be often enough these days, healthy dividend yields provide a measure of stability.

Long-Term Prospects

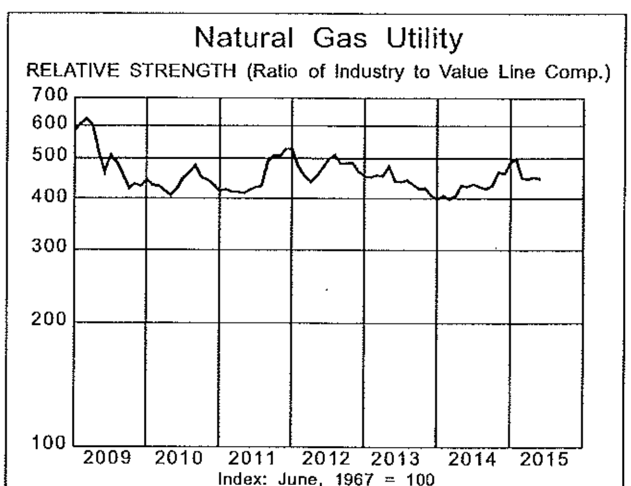
We are generally upbeat about the sector's operating performance over the next three to five years. Indeed, natural gas should remain abundant in this country, thanks to new technologies, so a shortage does not appear likely anytime soon. Moreover, there are limited alternatives for the services the 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. Lastly, the nation's population ought to continue on a steady, upward course, which augurs well for future demand for utility services.

Still, there are risks to keep in mind. For a start, companies are subject to state and local regulatory authorities. That being the case, there are no guarantees that petitions for rate increases will be accepted or certain favorable measures (such as temperature-adjusted rate mechanisms) will continue indefinitely. To further complicate matters, there may be future legislation passed by federal or state authorities calling for a considerable reduction in greenhouse gas emissions, which could result in increased compliance costs or additional operating restrictions on businesses. Moreover, a slowdown in the economy might lead to customers using less gas and cause bad-debt expense to climb. Finally, operational problems created by leaks and other accidents may result in considerable financial losses (if not adequately covered by insurance).

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). Year-ahead-focused accounts should find some appealing choices here, also. It is important to mention that companies with larger non-regulated 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. Note that *Chesapeake Utilities,* with operations in such states as Delaware, Maryland, and Florida, has joined the group.

Frederick L. Harris, III



The Water Utility Industry consists almost exclusively of regulated water companies. Thus, these utilities are monopolies in the markets where they operate, but state regulators establish the returns that can be earned on their investments.

California is in the midst of an historic drought. Three utilities in this industry have a major presence in the state. Due, in part, to reasonable regulation, these conditions have not had a meaningful impact on any of the companies.

The water infrastructure in the United States is in need of a major overhaul. Capital improvements have been deferred by just about every water system for years, if not decades. Large sums of money will be required to remove and replace old pipeline distribution systems.

Consolidation should continue to occur as small, cash-strapped, municipally-run water districts sell themselves to large investor-owned companies that have access to the funds needed to modernize systems.

Yield spreads continue to tighten between water utility stocks and the median dividend yield for equities that do distribute income to shareholders.

California's Historic Drought

Several years into a severe lack of rain and mountain snow, the state is in the midst of a severe water shortage. Governor Brown recently mandated that residents reduce water consumption by 25%. How is this situation effecting water utilities operating there? Surprisingly, the three company's in this issue that distribute water in the Golden State, *American States Water*, *California Water*, and *SJW*, have not really been negatively impacted in a meaningful way. We believe constructive regulation by the California Public Utilities Commission (CPUC) is the reason why. In what is not typically identified as a business-friendly state, the CPUC has acted prudently in getting utilities on board in helping to reduce water consumption. Usually, the more water a company sells, the higher the profits it can generate. Conversely, when demand declines, revenues and profits decrease. Thus, it is not in the best interest of water utilities to help curtail demand. The CPUC has resolved this conflict by using a mechanism called "decoupling." Basically, this allows water companies to promote less water usage without their bottom lines taking a bit hit.

An Aging Water Infrastructure

America's water distribution is in terrible shape. This is the result of years of deferring much needed maintenance and modernization. Both investor- and municipally-owned systems are now faced with burdensome construction budgets. Unfortunately, many of the over 50,000 domestic water districts do not have the financial wherewithal to fund the required improvements. As a result, the large companies in this sector have been on acquisition sprees. Instead of making one or two substantial takeovers, most of the purchases are of the tuck-in variety. Because this is one industry that is filled with redundancies, synergies can actually be achieved that help to fuel earnings growth.

INDUSTRY TIMELINESS: 64 (of 97)

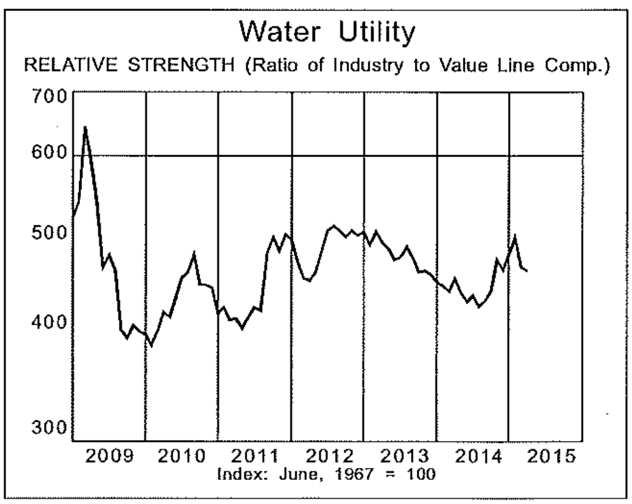
External Financing Will Be Required

To finance the projected capital outlays, water utilities will be forced to issue new debt and equity. Currently, most of these companies have decent balance sheets. (Not one equity in the group has a Financial Strength rating lower than a B+.) Over the next three- to five-year period, we expect the financial metrics of the industry to decline somewhat. Still, there doesn't appear to be any one utility that is expected to become highly leveraged during this period. Much of this is due to relatively constructive state regulatory commissions. Unlike electric utilities, which have been dealt some harsh rulings in the past, in general, authorities have been fair to the water sector. This is probably due to the differences in the industries. Digging up and replacing old pipes is more of a pay as you go operation, whereas, electric utilities sometimes have to spend hundreds of million of dollars on a plant that when finished, could result in huge increases in homeowners monthly bills.

Conclusion

The water utility industry has many positive attributes. State regulators are reasonable, the group has relatively solid finances, earnings are well defined and they don't face market risk that nonregulated industries do because of their monopoly status. However, almost all of the good news appears to be reflected in many of the utilities' stock prices. Out of nine companies, only *American States Water* is ranked to do better than the broader market averages in the year ahead. Moreover, the dividend yields on these stocks are much closer currently than in the past to the yield of the median stock that pays a dividend in the *Value Line* universe. This probably is due to the steep decline in interest rates that has occurred in the U.S. over the past several years. Low bond yields seem to have driven many income-oriented investors into the equity markets. All of this money chasing income has brought down the yield on water utilities, relative to the average stock. Currently, the yield of a typical water utility equity is only about 60 to 65 basis points higher than the average stock. This spread is very low, on an historical basis.

James A. Flood



CASE: UG 287
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 808

Risk Assessment

Exhibits in Support
of Opening Testimony

July 31, 2015

STAFF EXHIBIT 808

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-094 IN UG 287

CASE: UG 287
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

July 31, 2015

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 since March of 2007. I am a Senior Economist within the Energy, Rates, Finance, and Audits Division. My business address is 201 High St. SE, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. I will be addressing 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. A long-recognized "rates shock" exception to cost causation is to limit class revenue requirement increases to some designated level above the overall average.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared exhibits connected with each of the topics listed below.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please give us an overview of your testimony.

A. There have been an extraordinary number of years since the Cascade Natural Gas Corporation (Cascade or Company) has approached this Commission for general rate relief. That has undoubtedly contributed to Cascade's cost allocations and rates departing in a major way from industry standards. The focus of my testimony is upon two areas where the departures are most conspicuous—the identification and allocation of main extension costs and the residential customer charge. I will adjust for what I believe are grossly under-estimated main extension costs, and will follow that up with its rate spread consequences—primarily the elevation of costs allocated to the residential customer class. As regards the monthly residential customer charge, I am proposing to elevate it from three dollars, or around one-third the Oregon utility norm, to five dollars, which is little over half of the Oregon standard of eight to ten dollars a month.

I will now add a caveat with regard to the rate spread results—particularly how they affect the residential and commercial schedules and the special contracts schedule. Cascade did not functionalize its costs according to the legislative intent—an intent which has been honored by Avista and by our two largest electric utilities. The standard rate spread approach is to separate the accounting/ embedded costs according to the functions named in the legislation, and then to allocate *within* the functions according to the shares of the long-run incremental costs (LRIC) developed for the respective functions. Having done that, each customer schedule's revenue requirement share is the sum of those allocations. Cascade did not functionalize the embedded costs, but instead summed up the simple LRIC figures and then based the total revenue requirement allocations to the customer schedules upon the schedules' shares of the sums of those sums. There never was a step where the total embedded costs were separated functionally. My detailed footnote #16 (on page 10) describes the distortions that might be introduced owing to the absence of functionalization. *Given the threat of such distortions, Staff is reluctant to make its rate spread recommendations definitive at this stage of the case.*

Topic 1: Main Extension Identification and Cost Allocation

Q. When I visualize a gas distribution company I see a massive array of pipes. How is that array categorized and labeled?

A. The pipes running up and down what are mostly residential streets are referred to in the industry as "main extensions." or "customer mains."[1] The pipes that deliver the gas into the neighborhoods are referred to as "core mains" or "system core mains."[2] The pipes that connect the customers' meters to the main extensions are labeled "services" or "service lines."

[1] Avista employs the former label; Cascade employs both.
[2] Utah's Questar gas utility refers to these core mains as "feeders" and "large diameter mains."

Q. What is Cascade's general demographic?

A. Like the Avista gas utility in Oregon, Cascade serves towns and smallish cities in what are regarded as the more rural areas of the state.[3] (It is generally uneconomic for gas utilities to have much of a presence outside of the towns themselves.) Eighty-eight percent of Avista's customers are residential versus eighty-five percent for Cascade. In contrast with heavily urbanized areas with their high residential densities owing to small lots and more extensive apartment living, the residential customers in towns and smaller cities tend to live in single-family dwellings and enjoy larger lot sizes.

Q. I see that you make reference to Avista extensively in this testimony. Why that utility?

A. The short answer is convenience and timeliness. Avista is the last gas utility to have gone through a general rate case here in Oregon, and they now have a pending new case—with new data.

Q. Based upon those demographics would you expect Cascade to have an extensive customer main system as compared to its core main system?

A. I certainly would. The ratio of Avista's customer main costs to core main costs, for example, is greater than four-to-one.[4] This is in line with my intuitive impression that the cumulative length of lines going up and down

[3] The largest city served by Avista is Medford, the largest by Cascade is Bend. Those cities' respective populations (circa 2006) are 66,638 and 59,779.

[4] Avista's customer main/main extension costs are found on line 11 of Staff/902, Compton/1; and that company's core main costs are on line 15 of that same exhibit. These are long-run incremental, or system replacement, costs.

streets has to be much greater than the lines that “feed” those line extensions.

Q. Does a similar relationship between customer main and core main total costs hold with Cascade?

A. No…quite the opposite: According to its exhibit, the total cost of Cascade’s customer mains is less than one-fourth of its core main costs.[5]

Q. How do you account for such a shocking disparity between these two utility’s figures?

A. The difference is primarily in the amount of footage of customer mains accounted for by each residential customer and the unit costs per foot of those same mains. Avista shows an average main extension of 112 feet per residential customer[6] while Cascade shows 59 feet.[7] Avista shows an average cost of $37.23 per foot[8] while Cascade’s cost is $7.69.[9]

Q. Would one explanation for Avista’s greater costs be that Avista’s figure includes installation costs whereas Cascade’s figure is just for the pipe by itself.

A. I thought of that, and submitted a data request to that effect. The response was that the $7.69 figure includes installation as well as the pipe itself.[10]

Q. Have you a basis for disputing the Cascade amounts?

---

5 Cascade’s customer mains cost are shown on line 21 of their exhibit CNG/501, Amen/Page 1 of 2; core main costs are shown on line 27 of that same exhibit.
6 *See* line 8 of Staff/903, Compton/1.
7 *See* line 25 CNG/502, Amen/Page 1 of 2.
8 *See* line 10 of Staff/903, Compton/1.
9 *See* line 26 CNG/502, Amen/Page 1 of 2.
10 *See* Compton/1 of exhibit Staff/908.

A. I do. I make use of figures found on Cascade's exhibit CNG/502, Amen/Page 1 of 2 and in Mr. Amen's Workpaper RJA-WP-3A, which I have replicated as exhibit Staff/904. The outcome of my analyses is to boost the residential footage for Cascade to 83 feet and the unit cost to $29.37 per foot. I believe these values are conservative in the sense that they are still well below the respective values for Avista.

Q. Please present your analyses, starting with boosting the residential footage.

A. Working off of CNG/502, Amen/Page 1 of 2 I first develop the number of miles of two-inch pipe[11] accounted for by residential schedule 101, commercial schedule 104, and industrial schedule 105. Multiplying the customer counts (line 3) by the average feet per customer (line 26) and dividing by 5280 feet per mile, I obtain miles of main extensions for each of those schedules as, respectively 662, 159, and 19. Those amounts sum to 840 miles. Now I turn to Mr. Amen's Workpaper RJA-WP-3A (exhibit Staff/904). Note that it shows 1196 miles of two-inch or smaller pipes, which I would dedicate entirely to main extensions.[12] What we have then are 356 miles (i.e., 1196 - 840) of two-inch mains that are unaccounted for. I conclude that Cascade has under-estimated its average main extension lengths by about 40% (356/840 = 0.426). Adding another 40% to Mr. Amen's 59 feet yields the 83 feet residential figure cited above. Again, that figure is modest compared to

[11] Line 24 shows two inches as the "typical size" for those schedules.
[12] Core mains, which deliver gas to the main extension networks, presumably account for most of the pipes shown in this exhibit of other sizes. By their nature, core mains have a larger diameter since they must accommodate a host of main extensions.

Avista's average of 112 feet.[13] Using the same 40% factor elevates the commercial average number of feet of main extensions from 85 to 119 feet, which compares with Avista's estimate of 568 feet for General Service schedule 420.[14] Not knowing how the two utilities constitute their first schedule above the residential level makes me hesitant to make too much of the disparity between the two companies' commercial figures. But I am confident in the use of the 119 feet for Cascade's commercial schedule as a conservative figure.

Q. Would you please now address the per-unit cost of customer mains/ main extensions?

Making the case for elevating Cascade's average customer mains pipe costs per foot can take two lines. First, the previous answer attributed the entire inventory of two-inch lines to being main extensions. (Larger diameter mains are required to bring the magnitude of gas needed to accommodate all of the gas delivered through the two-inch customer mains.) Mr. Amen's Workpaper RJA-WP-3A (exhibit Staff/904) shows the average cost of these mains as $29.37 per foot.

The second, more detailed line of reasoning is as follows: First recall that line 25 of CNG/502, Amen/Page 1 of 2 shows the residential and commercial pipe material for customer mains (or main extensions) as being made of plastic. Adding their two mileages of customer mains that indirectly were claimed by Mr. Amen as serving residential and small commercial

[13] *See* line 8 of Staff/903, Compton/1.
[14] *See* line 8 of Staff/903, Compton/1.

customers yields 821 miles (662 pus 159) supposedly of plastic two-inch pipe. But Workpaper RJA-WP-3A shows only 626 miles of plastic two-inch pipe and 553 miles of steel two-inch pipe, whose cost is shown as over seven times that of plastic pipe ($54.06/$7.56 = 7.15). That means that at least 195 miles (821 minus 626) of customer mains are made of steel rather than plastic. So the true average cost of serving the full 821 miles (Amen's figure) or 1149 miles[15] (my figure) of a mix of plastic and steel main extensions to serve residential and commercial customers is some combination of Mr. Amen's $7.56 figure and his $54.06 figure. For want of something better I shall use his weighted average of $29.37 per foot as the average cost for customer mains that serve residential and commercial customers (respectively, schedules 101 and 104). This figure is substantially below Avista's noted estimate of $37.23.

Q. Does your exhibit Staff/905 show, from an LRIC viewpoint, the allocation of plant-related costs based upon your having substituted longer and more costly main extensions?

A. Yes, they are shown on line 57 of that exhibit. For the reader's convenience, line 58 shows the allocations contained in the Company's application. I developed the line 57 values by employing the model built into Mr. Amen's spreadsheet, shown as exhibit CNG/502, Amen, which in turn is the architectural modeling basis for my exhibit Staff/905. The only departure from

[15] 1.40 x (662 + 159) = 1149.

Mr. Amen's model apart from the lines 26 and 27 footage and unit cost substitutions mentioned in your question is stated in the footnote.

Q. Are costs in addition to the plant-related costs displayed in your exhibit Staff/905 that must be taken into consideration?

A. Plant-related costs include plant-related O&M as well as depreciation, the rate of return, and taxes. In addition there are non-plant related O&M costs. They are shown as lines six through sixteen of my exhibit Staff/906.

Q. What are the total costs and their allocations based upon LRIC principles?

A. They are shown on line 29 of Staff/906.

Q. Are those line 29 costs the amounts that will be recovered from the various customer schedules through the tariff rates?

A. No, far from it. As is commonly the case, long-run incremental costs exceed embedded, accounting costs, which in turn reflect well depreciated plant rather than new, replacement plant. Other considerations include contractual barriers to rate increases for customers served under special contracts and the objection mentioned in the beginning of this testimony against elevating rates beyond some threshold of acceptability. But when some customers' rates are held down for whatever reason, other customers' rates must be elevated if the utility is to earn its authorized return on investment. The rate spread process is the label that the industry places on translating LRIC-based costs to the rates that will actually appear in the utilities' tariffs and the revenue requirement allocations that will underlie those rates.

Topic 2: UG 287 Rate Spread

Q. Would you please now walk us through the rate spread process for this docket? By that I mean show us the steps by which the final revenue requirement increases or decreases are obtained.

A. Certainly. I will organize this portion of the testimony by displaying numbered steps. And except where indicated, I will make use of Cascade witness Ronald Amen's spreadsheet modeling architecture that is represented in his exhibit CNG/501, and which in turn is represented in my exhibit Staff/906. In most cases the steps themselves are quite different from Mr. Amen's.

Step 1: Obtain the revenue requirement target that has been developed by accounting and cost of capital personnel. That amount is shown under the Total column on line 40 of Staff/906. To achieve a direct comparison with Mr. Amen's approach and results, I will work with the same revenue requirement that he uses.

Step 2: Perform an explicit LRIC-based allocation of the revenue requirement target as shown on the rest of the columns of line 40 of Staff/906. The figures in those designated customer schedule columns bear the same ratio to the revenue requirement target as the corresponding figures in lines 29 and 36 bear to the total of those lines.[16]

[16] Apart from providing some visibility to relative LRIC sums for the indicated functional cost categories, including lines 31 through 36 of our shared exhibit, CNG/501 and Staff/906, adds nothing to the analysis. The items in the Total column for those lines are simply the sum across the schedules' columns, where each schedule's amount is simply obtained by summing the respective LRIC values from earlier in the spreadsheet. I believe the legislative intent of functionalization is to substitute *embedded cost components* of the target revenue requirement in the Total column cells, and then enter into the customer schedule columns the proportionate shares of each column that are

Step 3: Enter the different customer schedules' revenues that are being produced by the prices that are now in effect. Those revenues are shown on line 38. These values come by combining tariff prices with sales volumes forecasts—i.e., by summing the products of the billing determinants' p's and q's.

Step 4: Display, in line 43, the dollar increases (or decreases) to bring the total and each customer schedule into alignment with the target revenue requirement—*where the customers' allocations are entirely LRIC-based*. Line 43 is simply the difference between line 40 and line 38.[17]

Step 5: Decide upon some selective maximum increases--largely by making reference to line 42, which shows the percentage increase/decrease necessary to bring the respective customer schedules revenues in line with their LRIC-based cost allocations. Line 46 shows those maximum

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identical to the shares of that function's LRIC total that appear previously in that spreadsheet. For example, let's say that the target embedded revenue requirement for the System Core Mains by itself is $20 million. That value would appear as the Total value on line 35, and the figures obtained for the rest of the columns in that line would be based upon their respective proportionate shares of the LRIC function total on line 27. Since Residential Schedule 101 is seen as accounting for half the LRIC costs on line 27, it would be allocated half of the Total on line 35, or about $10 million in our example. Mr. Amen has not introduced the embedded functional revenue requirements in his lines 31 through 36, but simply aggregates figures from the lines that appear earlier in the spreadsheet. As I just stated, the allocations on line 40 did not require the cost functionalization of lines 31 through 36, but they are obtained directly from the respective shares of the line 29 total that appear on that line. I would note that embedded cost functionalization will yield different results from merely aggregating LRIC figures if the different functions have substantially different relationships between embedded, accounting costs and LRIC costs. For example, while the residential schedule "only" accounts for about half of core mains costs in this worksheet, that schedule accounts for seventy percent of meters, services and mains extensions. At the same time, on an LRIC basis the total cost for meters, etc. (line 34) is about double the total cost for core mains (line 35). Now if on an embedded cost basis the cost of meters, etc., is four times the embedded cost of core mains, then the combined allocation to the residential class would be increased over the Cascade aggregated cost approach owing to the fact that the residential share of the larger embedded cost item (meters, etc.) is greater than its share of what is now a proportionately smaller cost item, core mains.

[17] Line 41 may provide some interest at this stage of the rate spread development, but it can be eliminated without interfering with the steps needed to obtain the final revenue requirement recommendations.

percentage increases. In the case of schedules 170 and 900, the large indicated percentage decreases argue for, at least, no increase at all. The treatment of schedules 104 and 163/164, where more or less modest *decreases* seem to be in order, is more judgmental. I have chosen to set the schedule 163/164 *increase* at half the12.51% overall average level, or 6.26%; and the commercial schedule 104 *increase* at two-thirds the overall average, or 8.34%. Later in this testimony it will be made clear why those latter schedules should receive any increase at all when the LRIC figures indicate a decrease.

Step 6: Determine, in aggregate, how much the other schedules' allocations can be reduced owing to the just-described allocations to schedules 170, 900, 163/164, and 104 that are above their respective LRIC base-justified amounts. The contributions from each of those schedules are calculated, on line 47, as the product of the respective current revenues (line 38) and the difference between the LRIC base percentage increase/decrease shown on line 42 and the proposed effective percentage increase shown on line 46. Take a simple example: While the LRIC basis suggests that schedule 900 should receive a decrease of $1,035,534, denying that decrease to schedule 900 means that in aggregate the other schedules will be allowed to have their allocations reduced by that same $1,035,534. Line 47 shows the individual schedule and aggregate amounts by which the indicated schedules have their allocations increased above and beyond what was justified by the LRIC results.

Step 8: Allocate the revenue requirement reduction from line 47 to the rest of the customer schedules in proportion to their relative LRIC base allocations (replicated on line 48) to yield the new set of preliminary schedule revenue requirement increases that are shown on line 49. Line 50 shows the percentage increases associated with the dollar increases of line 49. These are the preliminary revenue requirement percentage increases to go along with those on line 47.

Step 9: Determine if any of the line 50 percentage increases exceed some benchmark level. The Company in this case has chosen 28.15% (shown on line 53) as the maximum. I accept that figure in order to facilitate comparing my general approach with Mr. Amen's. (While 28.15% seems too high as an absolute value, its multiple of two and one-fourth times the average, or even 10 percent if it is greater, is reasonable assuming the ultimate average increase is not more than three percent.) The 33.86% figure for Industrial Service schedule 105 exceeds that 28.15% benchmark.

Step 10: Bring the schedule 105 incremental revenue requirement down to the 28.15% level, and allocate the associated dollar reduction to the two schedules whose maximums have not already been established--i.e., schedules 101 and 111. This is done on line 54, where the offset to the reduction in the schedule 105 revenue requirement is allocated to schedules 101 and 111 in proportion to their adjusted incremental revenue requirements of line 49.

Step 11: Display the final recommended percentage and dollar revenue requirement increases for each of the customer schedules. This is done on lines 56 and 57.

Q. I now think I see why you wanted to give schedules 104 and 163/164 increases even though the LRIC values (lines 42 and 43) indicated decreases. Is it to mitigate what are going to be large increases to the schedules which are not being exempted from increases?

A. Yes.

Q. From line 4 of your exhibit Staff/906 I observe that Special Contracts schedule 900 accounts for two-thirds of Cascade's throughput, yet from line 38 they account for only six percent of current revenues. Does that give you cause for concern, and if not, why not?

A. Indeed it caused a lot of concern on my part—triggering a number of data requests. Compton/2 through Compton/7 of my exhibit Staff/908 reproduces some key responses to those requests. The Company claims that the subject customers are served entirely with mains dedicated to them. That means they do not benefit from core main costs.[18]

Q. In recent Avista cases Staff has recommended rate reductions for the large industrial customers based upon the LRIC results. Why is Staff not recommending reductions in this case?

[18] Note that Interruptible schedule 170 is allocated a portion of the system cost mains that is classified as commodity-related. The principle behind allocating some core main costs on a commodity basis is that much of a gas utility's investment is in the interest of safety—a matter which affects all customers and which is independent of their demands upon the core mains' peak capacity. That schedule pays nothing towards the capacity-related portion under the theory that, being interruptible, they don't contribute to the system peak for engineering/ planning purposes.

A. Frankly I remain concerned about Cascade's large industrial rates being so low compared to Avista's even without a reduction on Cascade's part. My exhibit Staff/909, Compton/1 shows on line 18 *current* margin revenues[19] for Avista's Transportation Service SCH 456 (which is the closest equivalent to Cascade's Special Contracts Schedule 900) of $3,330,000. Dividing that amount by annual throughput (39,791,532 therms, line 1) yields 8.37 cents per therm. Dividing Staff's recommended Cascade schedule 900 margin revenues (line 58) of $1,787,429 by the indicated throughput (line 4) of 228,441,210 *therms* yields *0*.782 cents per therm, or less than one-tenth of Avista's amount.

Q. Have you replicated Cascade's recommended dollar and percentage increases for the customer schedules?

A. Yes, those figures are found on lines 59 and 60 of exhibit Staff/906.

Q. How do you explain such a large shift in costs onto the Residential schedule 101?

A. The shift was caused by the increase in the line extension costs that were allocated to the residential class. The justification for that increase was the subject of the previous section of this testimony.

Q. Earlier you made comparison between Cascade and Avista with respect to line extension costs. I understand that Avista also has a pending general rate case. If both companies receive their sought for increases, and Cascade's residential customers receive the cost allocation that

[19] Margin revenues exclude purchase gas costs recovery.

***Staff* recommends, how will Cascade's residential rates compare with the residential rates that Avista *currently* charges?**

A. Using both the five dollar customer charge that I will also be recommending, the comparative base rates come out as follows[20]:

	Residential Rates	
	Cascade/Staff[21]	Avista[22]
Monthly Customer Charge	$5	$8
Per Therm Volumetric Charge	$0.39124	$0.54073

Note that Cascade's residential rates are well below Avista's despite the healthy increase recommended by Staff.

Q. Relative to the Company you also propose a reversal regarding commercial service schedule 104: Your recommendation is below the overall average whereas Cascade's is above. Can you provide some corroboration of your recommendation by also showing how Cascade's commercial rates would compare with Avista's *current* rates?

A. Yes, it is as follows:

	Commercial Rates	
	Cascade/Staff[23]	Avista[24]
Monthly Customer Charge	$5	$14
Per Therm Volumetric Charge	$0.27054	$0.43901

[20] These are base rates, i.e., exclusive of supplemental schedules--which are intended to be temporary. Also not shown is the $0.57535 that Cascade pays for its gas and which is passed on directly to customers.
[21] Source: Line 60 of Exhibit Staff/906, Compton/1.
[22] Source: Exhibit Staff/909, Compton/2. It is a replication of UG 288, Avista/903, Ehrbar/Page 4 of 4.
[23] Source: Line 61 of Exhibit Staff/906, Compton/1.
[24] Source: Exhibit Staff/909, Compton/2.

Q. I notice that Cascade is proposing to leave its Commercial Schedule Basic Service Charge at only $3 per month, yet in the immediately preceding table you show it to be $5. Please explain.

A. Staff herewith proposes that the basic service charge be elevated to $5 as shown in the table. Rationale for that change—and not a greater one—is provided in the following segment of this testimony.

Topic 3: The Residential Customer Charge

Q. You have spoken of elevating the monthly residential customer charge from three dollars to five dollars. What is the basis for that recommendation?

A. Cascade has found annual residential per-customer carrying costs for services and meters & regulators as, respectively, $172.59 and $27.02.[25] Add those two numbers together and dividing by twelve yields a monthly customer cost of $16.63.[26] Other utilities charge $8 to $10 per month, which is still below their explicit customer costs. Given a fixed revenue requirement target, when small-use customers pay a customer charge that is well below costs, the outcome is for them not to cover their full costs—thereby forcing a subsidy from the larger-use customers within the class.

Q. How does the Company justify having a customer/basic charge that is so far beneath the industry standard?

[25] Respectively, on lines 12 and 19 of my Exhibt/905, Compton/1. These costs are part of Mr. Amen's LRIC study, but when, in DR No. 212 (replicated as Compton/8 of my exhibit Staff/908), I asked for embedded cost amounts, Mr. Amen referred merely to the back-up figures behind the cited LRIC numbers.

[26] To those two customer-cost categories should also be added the cost of meter reading and bill printing and postage.

A. In his response to my DR No. 291 (replicated as Compton/9 of my exhibit Staff/908), Mike Parvinen gave the following reasons:

1. "Narrowly defined" monthly customer-related costs are only $2.51.[27]
2. Cascade seeks to "encourage the direct use of natural gas. If the direct use of natural gas is to be promoted it does not help to have a high fixed or basic charge. Natural gas is much more of an option or choice for customers and Cascade is of the opinion that if the basic charge is set too high customers will be less likely to choose natural gas when they have to pay both an electric and natural gas bill, *particularly when there is no or little usage* [emphasis added]."
3. "…a low basic charge helps encourages [sic] conservation by providing a bigger impact on a customer's bill for saved volumes."
4. "Cascade believes that direct use of natural gas should be encouraged and promoted. Therefore, Cascade is promoting a rate structure that starts to build a foundation for such promotion and encouragement."

Q. Does Staff endorse those reasons, and if not, why not?

A. Generally Staff does not. I will address each of the four reasons as follows:

1. I have long thought that, throughout the industry, customer-related costs refer to costs explicit to individual customers—i.e., not shared in any way. That would include each customer's meter and service line, reading his meter, and preparing and mailing his bill. Using Cascade's own figures, they sum to over $17 a month. That is more than six times Mr. Parvinen's figure of $2.51.

2. Except where gas is a more efficient substitute for electricity, I have thought it was public policy to *not* "encourage the direct use of natural gas"--in keeping with a policy to generally *dis*courage energy consumption of all kinds. And in the case where "there is no or little [gas] usage" it is particularly *not* in

[27] Mike Parvinen counts as narrowly defined customer costs *only* the meter reading and billing costs, plus residential uncollectibles and customer account records and collection. The sum of the costs of those four categories is cited as $2.51 per customer per month.

the interest of the other gas customers to be carrying other customers who aren't covering the costs that they expressly impose upon the system (i.e., for their service lines and meters). Finally, the customers that all the other customers benefit from having on the system are the heavy-use customers, not the light-use customers. The former pay a disproportionate share of a utility's fixed distribution costs and are attracted by having the lower *volumetric* rates made possible by a higher customer charge.

3. Yes, greater volumetric charges discourage consumption, but economists tend to be okay with consumption as long as marginal costs are covered. The marginal cost of natural gas is well below the volumetric charge, which incorporates most of the utility's fixed distribution costs.[28]

4. "Encouraging and promoting" the direct use of natural gas conflicts with the previously mentioned objective of conservation.

Q. With regard to your #3 response, how about the case of customers already on the system but who are tempted to discontinue being natural gas utility customers? Isn't it better to get *some* fixed cost recovery through the basic charge rather than none?

A. I would say that if someone has invested in a natural gas appliance, he is unlikely to want to discontinue its use—replacing it with an electric appliance—owing to a two dollar increase in the customer charge. Gas will

[28] Cascade currently pays around fifty-seven cents per them for gas, and adds to that figure about thirty -six cents to cover its own costs. (*See* exhibit Staff/907, Compton/1.) External environmental costs are ignored here.

(almost) always be cheaper than electricity for space and water heating and clothes drying purposes.

Q. How about the case of seasonal customers who might want to be “turned off” during their off season so that they can avoid the customer charge? (I am aware of the $32 re-connection fee.)

A. There is a simple way to deal with that threat. It is to impose the recovery of lost monthly minimum bills along with the explicit re-connection charge. Cascade’s residential tariff does not include that cost recovery vehicle. Avista’s does: The recoverable monthly minimum is defined as the monthly basic charge, which for Avista is currently eight dollars. Staff strongly recommends that Cascade also require that reconnection billings include the customer charges that weren’t collected while the seasonal customer was turned off.

Q. Given that your five dollar monthly customer charge proposal is so far beneath your narrowly defined customer costs, why isn’t Staff recommending a larger increase?

A. I refrain from doing so in the interest of the generally accepted regulatory objective of rates stability.

Q. Have you prepared an exhibit which shows the monthly basic charges and per-therm volumetric, or delivery, charges that are a) current, that are b) proposed by the Company, and that are c) being proposed by Staff.

A. Yes I have; it is exhibit Staff/907. For purposes of comparison, the two proposals shown in page 1 of this exhibit assume that Cascade will be awarded the full revenue requirement in its application and that its residential cost allocation will prevail. Page 2 of this exhibit is the same except for its adoption of Staff's residential cost allocation. A reduction in the ultimately awarded revenue requirement will likely be reflected in the per-therm delivery charges contained in both pages.

Q. You spoke of rates stability, but I observe in your exhibit Staff/907, Compton/1 that several months have residential same-month, year-to-year residential increases of around ten percent or more. Does that concern you?

A. Not at all. What most customers pay the most attention to is their monthly billings. In Staff's case, and given the Company's residential cost allocation (page one of this exhibit), there is no month where the general rate increase would cause the average customer's bill to go up by even two dollars. On the other hand, with Cascade's proposal there is one month that would experience a four dollar increase and two other months where the increase is around three-fifty or above. But I would note that the billing increases in both cases are not what I would call substantial.

Q. How about if Staff's residential cost allocation is adopted (page 2 of Staff/907)…then what happens to rates stability?

A. Combining my proposed 16.39% margin increase with a PGA commodity rate of $0.57535 yields an overall percentage increase of 6.87% for the average residential customer as opposed to 3.48% given the Company's proposed allocation.[29] (Again recall that a reduced revenue requirement will reduce both percentages.) So whether it's the Company's rate design with its three dollar customer charge or the Staff's rate design with its five dollar customer charge, the Staff's cost allocation would cause an increase in the average of 3.39% (6.87% – 3.48%) over the Company's cost allocation. But that differential aside, and referring to Staff/907, Compton/2, the same conclusion that I reached in the previous answer regarding comparative rates stability holds in this case. In dollar terms, the monthly increases are much more stable with the larger customer charge.

Q. Does this conclude your direct testimony?

A. Yes.

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[29] *See* lines 4 of, respectively, Compton/2 and Compton/1 of Staff/907.

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

July 31, 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 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 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

July 31, 2015

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 Contra Service SCH 447	Transportation Service SCH 456
	STATISTICS										
1	2016 ANNU			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 CUST			98,647	87,065	11,416	83	35	9	3	36
3	AVERAGE ANNUAL THERM DE				563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4	Gas Commodity Costs		$	-	-	-	-	-	-	-	-
5	Gas Supply Department (Scheduling)	1.03189	$	56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)		$	142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading		$	116,123	102,489	13,439	98	41	11	4	42
8	Billing		$	2,437,937	2,151,696	282,139	2,051	865	222	74	890
	Customer Installation Investment Cost										
9	Meters		$	4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
10	Services		$	41,791,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	260,891
11	Main Extensions		$	107,857,825	63,792,293	42,572,013	331,741	229,674	35,972	18,573	877,559
12	Total Customer Installation Investment Cost		$	154,509,966	103,163,613	49,134,017	530,280	385,846	58,309	47,507	1,190,394
	System Core Main Cost										
13	Capacity		$	12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14	Commodity		$	12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost		$	24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost		$	1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost		$	183,135,015	116,711,603	55,237,265	1,249,150	1,018,121	84,421	981,338	7,853,118

Source: Exhibit No. 801, Miller/Avista, Page 1 of 3

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 903

Exhibits in Support
Of Opening Testimony

July 31, 2015

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
	SERVICE INSTALLATIONS 48 yr life				
1	TYPICAL SERVICE PIPE SIZE		3/4"	3/4"	1 1/4" - 2"
2	AVERAGE SERVICE COST		$ 2,342.11	$ 2,633.95	$ 10,227.33
3	LEVELIZED PLANT COST FACTOR		0.1762	0.1762	0.1762
4	ANNUAL REVENUE REQUIREMENT		$ 412.68	$ 464.10	$ 1,802.06
	METERS & REGULATORS 36 yr life				
5	METERS & REGULATORS		$ 216.00	$ 604.88	$ 3,223.91
6	LEVELIZED PLANT COST FACTOR		0.1830	0.1830	0.1830
7	ANNUAL REVENUE REQUIREMENT		$ 39.53	$ 110.69	$ 589.98
	MAIN INVESTMENT 58 yr life				
8	AVERAGE MAIN EXTENSION PER CUSTOMER		112	568	382
9	TYPICAL PIPE SIZE REQUIRED		2 "	2 "	sample
10	AVERAGE COST PER FOOT		$ 37.23	37.23	59.3
11	MAIN EXTENSION INVESTMENT		$ 4,155.98	$ 21,151.85	$ 22,670.93
12	ESTIMATED DESIGN D/	100%	22.35%	24.81%	52.95%
13	INCR CAPACITY MAIN I	0.152883	$ 0.684040	$ 0.616215	$ 0.288731
14	2016 AVERAGE THERM .		563	2,332	55,280
15	CAPACITY MAIN INVESTMENT		$ 385.11	$ 1,437.01	$ 15,961.04
16	INCR COMMODITY MAIN INVESTMENT PER THERM		0.540957	$ 0.540957	$ 0.540957
17	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280
18	COMMODITY MAIN INVESTMENT		$ 304.56	$ 1,261.51	$ 29,904.11
19	TOTAL MAIN INVESTMENT PER CUSTOMER		$ 4,845.66	$ 23,850.38	$ 68,536.08
20	LEVELIZED PLANT COS 58 yr life		0.1763	0.1763	0.1763
21	ANNUAL REVENUE REQUIREMENT		$ 854.29	$ 4,204.82	$ 12,082.91
	UNDERGROUND STORAGE INVESTMENT				
22	BALANCING INVESTMENT PER TOTAL THROUGHPUT THERM		$ 0.005839	$ 0.005839	$ 0.005839
23	STORAGE INVESTMENT PER JANUARY SALES THERM		$ 0.381926	$ 0.381926	$ 0.381926
24	2016 AVERAGE THERMS PER CUSTOMER		563	2,332	55,280
25	2016 AVERAGE JANUARY SALES THERMS PER CUSTOMER		94	379	5,531
26	UNDERGROUND STORAGE INVESTMENT		$ 39.19	$ 158.37	$ 2,435.23
27	LEVELIZED PLANT COS 48 yr life		0.1762	0.1762	0.1762
28	ANNUAL REVENUE REQUIREMENT		$ 6.91	$ 27.90	$ 429.09
29	TOTAL INCREMENTAL INVESTMENT COST PER CUSTOMER		$ 1,313.40	$ 4,807.52	$ 14,904.03

Source: Exhibit No. 801, Miller/Avista, Page 2 of 3

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 904

Exhibits in Support
Of Opening Testimony

July 31, 2015

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Mains System Replacement Cost
Reference to Exhibit 502 Line 40

Size	Steel			Plastic			Others[1]			Total		
	Miles[2]	Cost/Ft (2014 $)[3]	Total Cost Ths. (2014 $)	Miles[2]	Cost/Ft (2014 $)[3]	Total Cost Ths. (2014 $)	Miles[2]	Cost/Ft (2014 $)[3]	Total Cost Ths. (2014 $)	Miles[2]	Cost/Ft (2014 $)[3]	Total Cost Ths. (2014 $)
<=2"	553	$54.06	$157,835	626	$7.56	$24,974	17	$29.37	$2,636	1196	$29.37	$185,445
>2"-4"	147	$113.72	$88,265	97	$14.05	$7,197	11	$74.10	$4,304	255	$74.10	$99,765
>4"-8"	98	$147.47	$76,307	8	$27.91	$1,179	1	$138.45	$731	107	$138.45	$78,217
>8"-12"	6	$184.52	$5,846	0		$0	0		$0	6	$184.52	$5,846
Total	**804**		**$328,252**	**731**		**$33,350**	**29**		**$7,671**	**1564**		**$369,272**

1. Unit cost used for other materials is weighted average of steel and plastic mains.
2. Source: PHIMSA
3. Source: Workpaper RJA-WP-3B

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 905

Exhibits in Support
Of Opening Testimony

July 31, 2015

Staff Mains Cost Alternative and LRIC Consequences

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Plant Carrying Costs

Line	Description	Unit	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163+164 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
1	**Billing Determinants**									
2	Peak Day Forecast	Dth-Day	83,138	46,988	32,086	2,617	1,447	0	0	0
3	Customer Count		69,254	59,252	9,839	111	13	32	4	4
4	Throughput	Dth	33,745,469	3,944,203	2,790,590	253,388	157,985	3,478,380	276,803	22,844,121
5										
6	**Service Installation**									
7	Typical Size	in.		0.5	1	2				
8	Material			Plastic	Plastic	Plastic				
9	Average Cost	$		$ 1,062	$ 1,180	$ 2,870				
10	Total Investment	$	$ 76,433,914	$ 62,948,429	$ 11,607,402	$ 318,405	$ 102,857	$ 1,090,286	$ 287,040	$ 79,495
11	Economic Carryin Charge Rate			16.25%	16.25%	16.25%	16.25%	16.25%	16.25%	16.25%
12	Annual Carrying Charge per customer	$		$ 172.59	$ 191.66	$ 466.30				
13	Class Annual Carrying Charge	$	$ 12,417,164	$ 10,226,363	$ 1,885,694	$ 51,727	$ 16,710	$ 177,124	$ 46,631	$ 12,914
14										
15	**Meters & Regulators**									
16	Average Cost	$		$ 186	$ 824	$ 5,944				
17	Total Investment	$	$ 23,835,053	$ 11,006,193	$ 8,108,673	$ 659,364	$ 434,415	$ 2,416,503	$ 540,116	$ 669,790
18	Economic Carryin Charge Rate			14.54%	14.54%	14.54%	14.54%	14.54%	14.54%	14.54%
19	Annual Carrying Charge per customer	$		$ 27.02	$ 119.87	$ 864.50				
20	Class Annual Carrying Charge	$	$ 3,466,628	$ 1,600,768	$ 1,179,345	$ 95,899	$ 63,182	$ 351,462	$ 78,556	$ 97,416
21										
22	Mains Investment									
23	A. Customer Mains Investment									
24	Typical Size	in.		2	2	2				
25	Material			Plastic	Plastic	Steel				
26	Avg. Mains extension per customer	ft	Staff's	83.00	119.00	899.14				
27	2013 Average cost per ft	$/ft	Substitutes	$ 29.37	$ 29.37	$ 54.83				
28	Customer mains investment per customer	$		$ 2,438	$ 3,495	$ 49,297				
29	Customer Mains Investment by Class		$ 214,556,721	$ 144,438,350	$ 34,386,021	$ 5,468,562	$ 1,434,783	$ 16,372,014	$ 2,270,035	$ 10,186,955
30										
31	B. Capacity Related									
32	Incr. mains capacity investment	$	$ 407,490	$ 180,287	$ 123,110	$ 10,041	$ 5,552			$ 88,500
33	Capacity Mains Investment per customer	$		$ 3.04	$ 12.51	$ 90.52	$ 427.06			$ 22,125.00
34	C. Commodity (Safety) Related									
35	Incr. mains commodity investment/therm	$	$ 4,115,887	$ 1,489,164	$ 1,053,608	$ 95,669	$ 59,648	$ 1,313,289	$ 104,509	
36	Safety Related Investment per customer	$		$ 25.13	$ 107.09	$ 862.42	$ 4,588.33	$ 41,040.27	$ 26,127.29	$ -
37										
38	Long-Run System Replacement Investment									
39	Mains System Replacement Cost	$	$ 369,272,368							
40	Less: Customer Mains Investment	$	$ (214,556,721)							
41	Long-Run System Replacement Investment	$	$ 154,715,648							
42										
43	Capacity	%	76%							
44	Investment per Peak Day Capacity	$/Dth-Day	$ 1,406							
45	Investment by Class	$	$ 116,869,617	$ 66,052,519	$ 45,104,365	$ 3,678,728	$ 2,034,005	$ -	$ -	$ -
46	Investment per customer	$		$ 1,115	$ 4,584	$ 33,162	$ 156,462	$ -	$ -	$ -
47										
48	Commodity	%	24%							
49	System Replacement Investment per Dth	$/Dth	$ 3.47							
50	Investment by Class	$	$ 37,846,031	$ 13,693,024	$ 9,688,044	$ 879,684	$ 548,472	$ 12,075,834	$ 960,973	
51	Investment per customer	$		$ 231	$ 985	$ 7,930	$ 42,190	$ 377,370	$ 240,243	$ -
52										
53	Total mains investment by class	$	$ 369,272,368	$ 224,183,893	$ 89,178,431	$ 10,026,974	$ 4,017,260	$ 28,447,847	$ 3,231,008	$ 10,186,955
54	Economic Carryin Charge Rate			16.85%	16.85%	16.85%	16.85%	16.85%	16.85%	16.85%
55	Class Annual Carrying Charge	$	$ 62,220,417	$ 37,773,785	$ 15,026,088	$ 1,689,491	$ 676,887	$ 4,793,310	$ 544,408	$ 1,716,447
56										
57	**Total Plant-Related Carrying Costs (Staff)**		$ 78,104,209	$ 49,600,916	$ 18,091,128	$ 1,837,118	$ 756,779	$ 5,321,896	$ 669,595	$ 1,826,778
58	Total Plant-Related Carrying Costs (Cascade)		$ 78,104,209	$ 42,316,319	$ 21,994,777	$ 2,554,887	$ 1,164,312	$ 7,397,459	$ 834,764	$ 1,841,689
59	**Note: Incremental capacity and safety related investments (lines 31 - 36) are disregarded under the theory that a fully replicated mains system would not require such.**									

Source: Tab "Staff.905" of Staff Workpapers "Compton.Exhibits905-906.Staff Revised Version of Amen Workpapers"

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 906

Exhibits in Support
Of Opening Testimony

July 31, 2015

Staff's Rate Spread

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Summary

Line #	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163+164 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
1	Billing Determinants								
2	Peak Day Forecast	83,138	46,988	32,086	2,617	1,447	0	0	0
3	Customer Count	69,254	59,252	9,839	111	13	32	4	4
4	Throughput (decatherms)	33,745,469	3,944,203	2,790,590	253,388	157,985	3,478,380	276,803	22,844,121
5	Non-Sch. 900 Throughput (Therms)	109,013,484	39,442,028	27,905,898	2,533,883	1,579,845	34,783,798	2,768,032	
6	O&M Costs: From CNG/501, Amen/Page 1 of 2								
7	Gas Supply Related	$ 165,321	$ 66,311	$ 46,673	$ 4,176	$ 2,565	$ 14,208	$ 3,960	$ 27,428
11	Customer Related	$ 2,108,061	$ 1,783,074	$ 310,653	$ 2,944	$ 1,795	$ 7,676	$ 960	$ 960
16	Subtotal: O&M Costs	$ 2,273,382	$ 1,849,385	$ 357,326	$ 7,120	$ 4,359	$ 21,884	$ 4,920	$ 28,388
17									
18	Customer Investment Carrying Costs: From Staff/905, Compton/1								
19	Meter	$ 3,466,628	$ 1,600,768	$ 1,179,345	$ 95,899	$ 63,182	$ 351,462	$ 78,556	$ 97,416
20	Service	$ 12,417,164	$ 10,226,363	$ 1,885,694	$ 51,727	$ 16,710	$ 177,124	$ 46,631	$ 12,914
21	Mains	$ 36,151,659	$ 24,337,089	$ 5,793,860	$ 921,423	$ 241,753	$ 2,758,597	$ 382,489	$ 1,716,447
22	Subtotal: Customer Investment Costs	$ 52,035,451	$ 36,164,219	$ 8,858,900	$ 1,069,050	$ 321,645	$ 3,287,183	$ 507,676	$ 1,826,778
23									
24	System Core Main Carrying Costs: From Staff/905, Compton/1								
25	Capacity	$ 19,691,905	$ 11,129,496	$ 7,599,844	$ 619,846	$ 342,719	$ -	$ -	$ -
26	Commodity	$ 6,376,854	$ 2,307,201	$ 1,632,384	$ 148,222	$ 92,415	$ 2,034,713	$ 161,919	$ -
27	Subtotal: System Core Main Costs	$ 26,068,758	$ 13,436,697	$ 9,232,228	$ 768,068	$ 435,134	$ 2,034,713	$ 161,919	$ -
28	Subtotal: Plant-Related Costs	$ 78,104,209	$ 49,600,916	$ 18,091,128	$ 1,837,118	$ 756,779	$ 5,321,896	$ 669,595	$ 1,826,778
29	LRIC - System Total: Plant-Related Plus O&M Costs	$ 80,377,591	$ 51,450,302	$ 18,448,454	$ 1,844,238	$ 761,138	$ 5,343,780	$ 674,515	$ 1,855,165
30									
31	Fuctional Cost Assignment by LRIC								
32	Scheduling & Planning	$ 165,321	$ 66,311	$ 46,673	$ 4,176	$ 2,565	$ 14,208	$ 3,960	$ 27,428
33	Meter Reading, Billing etc.	$ 2,108,061	$ 1,783,074	$ 310,653	$ 2,944	$ 1,795	$ 7,676	$ 960	$ 960
34	Meters, Services & Mains extensions	$ 52,035,451	$ 36,164,219	$ 8,858,900	$ 1,069,050	$ 321,645	$ 3,287,183	$ 507,676	$ 1,826,778
35	Sysctem Core Mains	$ 26,068,758	$ 13,436,697	$ 9,232,228	$ 768,068	$ 435,134	$ 2,034,713	$ 161,919	$ -
36	Total	$ 80,377,591	$ 51,450,302	$ 18,448,454	$ 1,844,238	$ 761,138	$ 5,343,780	$ 674,515	$ 1,855,165
37									
38	Non-Gas Revenue at Current Rates	$ 28,954,127	$ 16,312,863	$ 7,513,446	$ 472,884	$ 230,926	$ 2,295,862	$ 340,717	$ 1,787,429
39	Proposed Increase	$ 3,622,770							
40	LRIC Based Non-gas Rev Req.	$ 32,576,897	$ 20,852,717	$ 7,477,126	$ 747,466	$ 308,488	$ 2,165,825	$ 273,380	$ 751,895
41	Revenue to Cost Ratio		0.78	1.00	0.63	0.75	1.06	1.25	2.38
42	Required % Increase to Bring to LRIC Costs	12.51%	27.83%	-0.48%	58.07%	33.59%	-5.66%	-19.76%	-57.93%
43	Incremental Non-gas Revenue Req.	$ 3,622,770	$ 4,539,854	$ (36,320)	$ 274,582	$ 77,562	$ (130,037)	$ (67,337)	$ (1,035,534)
44									
45	Step 1								
46	Maximum Increase			8.34%			6.26%	0.00%	0.00%
47	Incremental LRIC Revenue Adjustment	$ 2,039,571		$ 662,941			$ 273,758	$ 67,337	$ 1,035,534
48	Unadjusted Incremental Non-gas Rev. Req. (Line 43)	$ 4,891,999	$ 4,539,854		$ 274,582	$ 77,562			
49	Adjusted Incremental Non-gas Rev. Req.	$ 2,852,428	$ 2,647,099		$ 160,104	$ 45,225			
50	Adjusted Revenue Shortfall Percentage		16.23%		33.86%	19.58%			
51									
52	Step 2								
53	Maximum Increase: 2.25 x 12.51%				28.15%				
54	Incremental LRIC Revenue Adjustment	$ (0)	$ 26,545		$ (26,999)	$ 454			
55	**Staff's Recommendations**								
56	Percent Increase	12.51%	16.39%	8.34%	28.15%	19.78%	6.26%	0.00%	0.00%
57	Total Margin Increase	$ 3,622,770	$ 2,673,644	$ 626,621	$ 133,105	$ 45,678	$ 143,721	$ -	$ -
58	Margin after Increase	$ 32,576,897	$ 18,986,507	$ 8,140,067	$ 605,989	$ 276,604	$ 2,439,583	$ 340,717	$ 1,787,429
59	Final percentage increase relative to system average		1.31	0.67	2.25	1.58	0.50	0.00	0.00
60	Residential Delivery Charge per Therm:	Assuming Customer Charge = $5:	$	0.39124		Assuming Customer Charge = $3:	$	0.42730	
61	Commercial Delivery Charge per Therm:	Assuming Customer Charge = $5:	$	0.27054					
62	**Cascade' Recommendations:** ***See*** **lines 53-55 and line 57 of CNG/501, Amen/Page 2 of 2.**								
63	Total Margin Increase	$ 3,622,770	$ 1,357,503	$ 1,410,135	$ 133,127	$ 65,011	$ 646,336	$ 10,658	$ -
64	Margin after Increase	$ 32,576,897	$ 17,670,366	$ 8,923,581	$ 606,011	$ 295,937	$ 2,942,198	$ 351,375	$ 1,787,429
65	Percent Increase	12.51%	8.32%	18.77%	28.15%	28.15%	28.15%	3.13%	0.00%
66	Final percentage increase relative to system average		0.67	1.50	2.25	2.25	2.25	0.25	0
67	Residential Delivery Charge per Therm:	Assuming Customer Charge = $5:	$	0.35787		Assuming Customer Charge = $3:	$	0.39393	

Source: Tab "Staff.906" of Staff Workpapers "Compton.Exhibits905-906.Staff Revised Version of Amen Workpapers."

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 907

Exhibits in Support
Of Opening Testimony

July 31, 2015

Cascade Natural Gas Corporation
Oregon Jurisdiction
Estimated Average Monthly Bill Comparison Under Proposed Rates

Cascade's Residential Revenue Requirement Assumed

OPUC Staff's $5 Residential Customer Charge Versus Cascade's $3

Residential Schedule 101

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
					Cascade			OPUC Staff			
			Present Rates		Proposed Rates			Proposed Rates			
1	**Monthly Basic Service Charge**		**$3.00**		**$3.00**			**$5.00**			
2	Delivery Charge per Therm		$0.35951		**$0.39393**			**$0.35787**			
3	PGA Rate per Therm		$0.57535		$0.57535			$0.57535			
4	Total Revenues		$39,005,836		$40,363,430			$40,363,191		40,363,430/ 39,005,936 =	1.03480491

Line No.	Month	Average Therms per Customer	Revenue at Present Rates	Cascade-Proposed: Revenue at Proposed Rates	Cascade-Proposed: Monthly Bill Change Amount	Cascade-Proposed: Monthly Bill Change Percent	OPUC Staff-Proposed: Revenue at Proposed Rates	OPUC Staff-Proposed: Monthly Bill Change Amount	OPUC Staff-Proposed: Monthly Bill Change Percent	Month's Therms	Customers
5	January	117	$ 112.38	$116.41	$4.03	3.58%	$114.19	$1.81	1.61%	6,959,343	59,252
6	February	107	$ 103.03	$106.71	$3.68	3.57%	$104.85	$1.82	1.77%	6,314,828	59,252
7	March	90	$ 87.14	$90.24	$3.10	3.56%	$88.99	$1.85	2.13%	5,352,642	59,252
8	April	64	$ 62.83	$65.03	$2.20	3.51%	$64.73	$1.90	3.02%	3,801,533	59,252
9	May	40	$ 40.39	$41.77	$1.38	3.41%	$42.33	$1.93	4.79%	2,381,868	59,252
10	June	25	$ 26.37	$27.23	$0.86	3.26%	$28.33	$1.96	7.43%	1,460,301	59,252
11	July	18	$ 19.83	$20.45	$0.62	3.12%	$21.80	$1.97	9.94%	1,072,634	59,252
12	August	14	$ 16.09	$16.57	$0.48	3.00%	$18.07	$1.98	12.29%	807,158	59,252
13	September	15	$ 17.02	$17.54	$0.52	3.03%	$19.00	$1.98	11.60%	889,375	59,252
14	October	23	$ 24.50	$25.29	$0.79	3.23%	$26.46	$1.96	8.01%	1,341,913	59,252
15	November	41	$ 41.33	$42.74	$1.41	3.41%	$43.26	$1.93	4.68%	2,402,871	59,252
16	December	101	$ 97.42	$100.90	$3.48	3.57%	$99.26	$1.83	1.88%	5,999,446	59,252
17	Total	655	$ 648.33	$670.88	$22.55		$671.26	$22.93		38,783,912	711,020
18	Monthly Average		$ 54.03	$55.91	$1.88	3.48%	$55.94	$1.91	3.54%		
19	Monthly Average **Range**				$0.48 - $4.03			$1.74 - $1.97			

20 Proposed Delivery Charges: Line 67 of Staff/906, Compton/1. Source of all other data: Tab "RJA-506 Res Monthly Impact" of "Copy of Amen Workpaper Cascade rate design"

21 Note: Total revenues based on billing determinants of 39,442,030 therms, as shown in CNG/501, Amen/Page 1 of 2, rather than the 38,783,912 contained on line 17 above.

Cascade Natural Gas Corporation
Oregon Jurisdiction
Estimated Average Monthly Bill Comparison Under Proposed Rates

OPUC Staff's Residential Revenue Requirement Assumed

OPUC Staff's $5 Residential Customer Charge Versus Cascade's $3

Residential Schedule 101

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Present Rates		**Cascade** Proposed Rates			**OPUC Staff** Proposed Rates			
1	**Monthly Basic Service Charge**		**$3.00**		**$3.00**			**$5.00**			
2	Delivery Charge per Therm		$0.35951		$0.42742			**$0.39137**			
3	PGA Rate per Therm		$0.57535		$0.57535			$0.57535			
4	Total Revenues		$39,005,836		$41,684,344			$41,684,499		41,684,499/ 39,005,836 =	1.06867339

Line No.	Month	Average therms per Customer	Revenue at Present Rates	Cascade-Proposed: Revenue at Proposed Rates	Cascade-Proposed: Monthly Bill Change Amount	Cascade-Proposed: Monthly Bill Change Percent	OPUC Staff-Proposed: Revenue at Proposed Rates	OPUC Staff-Proposed: Monthly Bill Change Amount	OPUC Staff-Proposed: Monthly Bill Change Percent	Month's Therms	Customers
5	January	117	$ 112.38	$120.32	$7.95	7.07%	$118.11	$5.73	5.10%	6,959,343	59,252
6	February	107	$ 103.03	$110.30	$7.27	7.05%	$108.44	$5.41	5.25%	6,314,828	59,252
7	March	90	$ 87.14	$93.25	$6.11	7.01%	$92.00	$4.87	5.59%	5,352,642	59,252
8	April	64	$ 62.83	$67.18	$4.35	6.92%	$66.87	$4.04	6.43%	3,801,533	59,252
9	May	40	$ 40.39	$43.11	$2.72	6.72%	$43.67	$3.27	8.11%	2,381,868	59,252
10	June	25	$ 26.37	$28.07	$1.70	6.44%	$29.17	$2.80	10.60%	1,460,301	59,252
11	July	18	$ 19.83	$21.05	$1.22	6.17%	$22.40	$2.57	12.98%	1,072,634	59,252
12	August	14	$ 16.09	$17.04	$0.95	5.91%	$18.53	$2.45	15.20%	807,158	59,252
13	September	15	$ 17.02	$18.04	$1.02	5.98%	$19.50	$2.48	14.56%	889,375	59,252
14	October	23	$ 24.50	$26.06	$1.56	6.37%	$27.23	$2.73	11.15%	1,341,913	59,252
15	November	41	$ 41.33	$44.11	$2.78	6.74%	$44.64	$3.31	8.00%	2,402,871	59,252
16	December	101	$ 97.42	$104.28	$6.86	7.04%	$102.64	$5.22	5.36%	5,999,446	59,252
17	Total	655	$ 648.33	$692.81	$44.48		$693.20	$44.87		38,783,912	711,020
18	Monthly Average		$ 54.03	$57.73	$3.71	6.86%	$57.77	$3.74	6.92%		
19	Monthly Average **Range**				$0.95 - $7.95			$2.45 - $5.73			

20 Proposed Delivery Charges: Line 67 of Staff/906, Compton/1. Source of all other data: Tab "RJA-506 Res Monthly Impact" of "Copy of Amen Workpaper Cascade rate design"

21 Note: Total revenues based on billing determinants of 39,442,030 therms, as shown in CNG/501, Amen/Page 1 of 2, rather than the 38,783,912 contained on line 17 above.

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 908

Exhibits in Support
Of Opening Testimony

July 31, 2015

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 210

Date prepared: May 20, 2015

Preparer: Ronald Amen

Contact: Pamela Archer

Telephone: (509)-734-4591

210. Line 27 of Exhibit CNG/502 Amen/Page 1shows the average cost of two-inch plastic pipe as being $7.69 per foot. The staff initiator of this question is persuaded that the $7.69 figure is grossly in error: Work papers provided in the last Avista general rate case has the installed cost of that same pipe being about seven times as great as the Cascade figure; counter-intuitively, "Customer Investment Carrying Cost" results shown on Lines 20 and 21 of Exhibit CNG/501 Amen/Page 1 has Service costs exceeding Mains costs. Please either confirm the existing cost per foot or correct the cost estimates for the pipes used for the mains and re-submit the affected exhibit pages. If you are confirming the existing cost estimate, provide the basis for how this cost estimate is derived including any Workpapers for which this cost estimate was derived.

Response:

The Mains cost attributable to two-inch plastic pipe was calculated using an analysis of all Cascade New Growth work orders over the period 2002-2013. Cascade believes that it is accurate. The support for the Mains cost is summarized in Workpaper RJA-WP-3B.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 205

Date prepared: May 20, 2015

Preparer: Ronald Amen

Contact: Pamela Archer

Telephone: (509)-734-4591

205. Lines 12-16 of Exhibit CNG/500 Amen/11 refers to "the distribution main segments connected to the individual [non-core classes' and larger core classes'] customers [being] identified using Cascade's Geographic Information System." To what degree do those customers make use of distribution mains that also carry gas to the smaller-scale customers as opposed to solely making use of dedicated mains that go all the way to the interstate transmission suppliers' point of delivery to Cascade?

Response:

The answer referenced by the request on Exhibit CNG/500 Amen/11 describes Cascade's distribution mains analysis that derives the customer related costs associated with the installation of distribution mains to connect new customers. Having identified the specific distribution mains segments to which the classes identified in the request are connected, these classes do not make use of the minimum size distribution mains that connect smaller-scale new customers.

Please refer to the response to Request No. 206 for a description of the basis for the allocation or assignment of the remaining categories of distribution mains to the non-core and larger core classes.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 208

Date prepared: May 20, 2015

Preparer: Ronald Amen

Contact: Pamela Archer

Telephone: (509)-734-4591

208. Exhibit CNG/502 Amen/Page 1, Line 36 indicates that there is no Commodity/Safety-related investment on behalf of Schedule 900 Special Contract customers. Explain why such is the case with this schedule but not with combined Schedules 163 and 164.

Response:

As stated in the response to Request No. 206, the high pressure transmission mains serving the Schedule 900 Special Contract customers have been traced back to the pipeline gate stations from which the customers are served. All related capital investments for Schedule 900 were separately identified and assigned to that class. Therefore, Schedule 900 was excluded from the Commodity/Safety related investment allocation.

No separate identification was performed for Schedules 163 and 164. Therefore, these schedules were allocated a share of the Commodity/Safety related capital investments.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 209

Date prepared: May 20, 2015

Preparer: Ronald Amen, Mike Parvinen

Contact: Pamela Archer

Telephone: (509)-734-4591

209. Exhibit CNG/501 Amen/Page 2, Line 35 indicates that there is virtually no System Core Mains LRIC Functional Cost Assignment to Schedule 900 Special Contract customers. Explain why such is the case.

Response:

There is $14,912 of System Core Mains LRIC Functional Cost Assignment to Schedule 900 Special Contract customers, which is determined by the capital investment directly assigned to Schedule 900, as described in the response to Request No. 206. Therefore, Schedule 900 has not been allocated a portion of the cost to replace the remainder of the entire System Core Mains, as shown on Exhibit CNG/502 Amen/ Page 2 of 2.

Notwithstanding the foregoing paragraph, each of the Special Contracts governing the transportation service to the Schedule 900 customers include a Section titled, "Regulatory Changes." The provisions of this section define an "Adverse Regulatory Action," which include actions that "materially and substantially alter the economic benefits secured by the rates established under this Agreement." Examples of substantial alterations that would constitute an Adverse Regulatory Action include but are not limited to "actions by the OPUC which require Cascade to make changes in accounting treatment or require Cascade to make changes in cost allocation or recognition of rate base, cost or revenue, or to the distribution transportation services furnished under this Agreement." The presence of an Adverse Regulatory Action could result in the termination of the Special Contract.

In addition to the foregoing Regulatory Changes provision, one of the Special Contracts provides that the party disadvantaged by an Adverse Regulatory Action "may cause the transfer of ownership of the Cascade pipeline, together with all necessary appurtenances, rights-of-way, easements and other rights, from Cascade to [Customer]." Mindful of these Special Contract provisions, and in view of the direct assignments of pipeline, service line, and metering facilities serving the Schedule 900 customers already present in the LRIC, Cascade believes it would be inappropriate to further allocate a portion of the replacement cost of the remainder of the entire System Core Mains to Schedule 900.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

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Utility Program

Request No. 288

Date prepared: June 30, 2015

Preparer: Ronald J Amen

Contact: Pamela Archer

Telephone: (509)-734-4591

288. Line 29 of Exhibit CNG/502 Amen/Page 1 shows $10,186,955 as the "Customer Mains Investment by Class" for Schedule 900. Is that figure based upon 2013 average costs (as is the case for Residential Service customers on line 27)? Is the $10,186,955 estimate the *entire* facilities *cost* (i.e., as *initially* installed) to connect the class members to the city gate(s)/transmission hub(s) – in other words do the *customer* mains double, or also serve as, *core* mains…meaning that Schedule 900 customers make no use, or almost no use, of the core mains whose costs are shown on line 35 of Exhibit CNG/502 Amen/Page 2?

Response: As shown in the previously provided Workpaper RJA-WP-5, the $10,186,955 amount for Schedule 900 is based upon historical costs for the entire facilities cost of the customer installations in that class (trended to 2014 dollars using Handy-Whitman indices) to connect the class members to the city gate(s)/transmission hub(s). To the extent that some of the mains do not exclusively serve the Schedule 900 class, thereby serving other customers either attached to these mains or core mains downstream from these facilities, Schedule 900 customers make no other use of the core mains.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 289

Date prepared: June 30, 2015

Preparer: Ronald J. Amen

Contact: Pamela Archer

Telephone: (509)-734-4591

289. Line 4 of Exhibit CNG/501 Amen/Page 1 shows Special Contracts throughput to be twice that of the rest of the customer classes' combined. Did any core main expansion (length or peak day capacity capability) occur with Cascade in order to meet that additional throughput?

Response: No.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 290

Date prepared: June 30, 2015

Preparer: Ronald J Amen

Contact: Pamela Archer

Telephone: (509)-734-4591

290. If the Cascade system were constructed de novo, in comparison with your current system would the new system's core mains have reduced length and/or peak day capacity given a projected permanent absence of the Schedule 900 customers and their 22.8 million therm annual throughput?

Response: No.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 212

Date prepared: May 20, 2015

Preparer: Ronald Amen

Contact: Pamela Archer

Telephone: (509)-734-4591

212. Referring to Exhibit CNG/501 Amen/Page 1, Lines 3, 19, and 20, and doing the arithmetic indicates the annual average "Customer Investment Carrying Cost" for meters and services for Residential Service Schedule 101 to be just under $200 per year, or over $16 per month. {([$1,600,768 + $10,226,363]/59,252) = $199.61; $199.61/12 = $16.63} Please provide the most recent available embedded/accounting cost figures, separately, for residential meters and residential services.

Response:

Please refer to Workpapers RJA-WP-1 (Services) and RJA-WP-2 (Meters).

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests
UG 287

Request No. 291

Date prepared: June 30, 2015

Preparer: Mike Parvinen

Contact: Pamela Archer

Telephone: (509)-734-4591

291. What is the Company's justification for its $3/month residential basic service charge when both embedded and incremental customer costs as narrowly defined are several times that amount?

Response:

First of all, both embedded and incremental costs as narrowly defined as Customer Related costs including meter reading, customer account records and collection, billing postage and printing, as well as uncollectibles, are $2.51 per customer per month. This calculation can be derived by taking the customer related costs found in Exhibit CNG/501 Amen/Page 1 of 2, sum of rows 12 – 15 in column 101, divided by customer count (row 3), divided by 12.

Cascade's proposed rate is supported by costs and from a policy perspective sets the tone to help encourage the direct use of natural gas. If the direct use of natural gas is to be promoted it does not help to have a high fixed or basic charge. Natural gas is much more of an option or choice for customers and Cascade is of the opinion that if the basic charge is set too high customers will be less likely to choose natural gas when they have to pay both an electric and natural gas bill, particularly when there is no or little usage.

On another note, a low basic charge helps encourages conservation by providing a bigger impact on a customer's bill for saved volumes.

Cascade believes that direct use of natural gas should be encouraged and promoted. Therefore, Cascade is promoting a rate structure that starts to build a foundation for such promotion and encouragement.

CASE: UG 287
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 909

Exhibits in Support
Of Opening Testimony

July 31, 2015

AVISTA UTILITIES
OREGON JURISDICTION
LONG-RUN INCREMENTAL COST OF SERVICE STUDY
TWELVE MONTHS ENDED DECEMBER 2016

RESULT SUMMARY ***(Component Allocation)***

Line No.		OREGON TOTAL	Residential Service SCH 410	General Service SCH 420	Large General Service SCH 424	Interruptible Service SCH 440	Seasonal Service SCH 444	Special Contract Service SCH 447	Transportation Service SCH 456
	STATISTICS								
1	2016 ANNUAL THERM DELIVERIES	131,581,172	49,018,942	26,621,408	4,588,281	3,975,023	258,498	7,327,488	39,791,532
2	2016 CUSTOMERS	98,647	87,065	11,416	83	35	9	3	36
3	AVERAGE ANNUAL THERM DELIVERIES PER CUSTOMER		563	2,332	55,280	113,572	28,722	2,442,496	1,105,320
4	Gas Commodity Costs	$ -	-	-	-	-	-	-	-
5	Gas Supply Department (Scheduling) 1.03189	$ 56,322	25,593	13,899	2,396	2,075	135	1,901	10,323
6	Gas Supply Department (Non-Scheduling)	$ 142,688	80,884	43,927	7,571	6,559	427	516	2,803
7	Meter Reading	$ 116,123	102,489	13,439	98	41	11	4	42
8	Billing	$ 2,437,937	2,151,696	282,139	2,051	865	222	74	890
	Customer Installation Investment Cost								
9	Meters	$ 4,860,423	3,441,492	1,263,699	48,968	35,115	6,118	13,086	51,945
10	Services	$ 41,791,718	35,929,828	5,298,304	149,571	121,058	16,218	15,848	260,891
11	Main Extensions	$ 107,857,825	63,792,293	42,572,013	331,741	229,674	35,972	18,573	877,559
12	Total Customer Installation Investment Cost	$ 154,509,966	103,163,613	49,134,017	530,280	385,846	58,309	47,507	1,190,394
	System Core Main Cost								
13	Capacity	$ 12,287,370	5,911,318	2,892,256	233,556	212,495	-	224,968	2,812,777
14	Commodity	$ 12,548,965	4,674,827	2,539,026	437,584	379,101	24,653	698,828	3,794,947
15	Total Core Main Cost	$ 24,836,335	10,586,145	5,431,282	671,140	591,595	24,653	923,796	6,607,723
16	Underground Storage Cost	$ 1,035,644	601,184	318,562	35,614	31,139	665	7,539	40,941
17	Long Run Incremental Distribution Cost	$ 183,135,015	116,711,603	55,237,265	1,249,150	1,018,121	84,421	981,338	7,853,118
18	**Distribution Margin Revenue at Present Rates**	**$ 53,224,000**	**34,864,000**	**13,605,000**	**687,000**	**463,000**	**44,000**	**231,000**	**3,330,000**
	Proposed Cost by Functional Classification Assigned to Schedule by LRIC components								
19	Cost of Gas Commodity	$ -	-	-	-	-	-	-	-
20	Gas Supply Department Costs	$ 568,000	303,900	165,043	28,446	24,644	1,603	6,899	37,466
21	Meter Reading, Billing, Etc. Costs	$ 3,686,000	3,253,222	426,575	3,101	1,308	336	112	1,345
22	Meters & Services Costs	$ 18,599,000	15,696,325	2,616,101	79,152	62,262	8,905	11,535	124,719
23	System Core Main Costs	$ 37,367,000	20,945,150	13,517,845	282,414	231,271	17,072	265,373	2,107,874
24	Underground Storage Costs	$ 1,561,000	906,149	480,161	53,680	46,934	1,002	11,364	61,709
25	**LRIC Based Target Margin**	$ 61,781,000	41,104,746	17,205,725	446,794	366,419	28,919	295,284	2,333,113
26	Current Distribution Margin Revenue to Proposed Cost	0.86	0.85	0.79	1.54	1.26	1.52	0.78	1.43
27	**Relative Margin to Cost at Present Rates**	1.00	0.98	0.92	1.78	1.47	1.77	0.91	1.66
28	Component LRIC Target Increase by Schedule	$ 8,557,000	$ 6,240,746	$ 3,600,725	$ (240,206)	$ (96,581)	$ (15,081)	$ 64,284	$ (996,887)
29	Target Increase as a Percent of Present Distribution Margin Revenue	16.08%	17.90%	26.47%	-34.96%	-20.86%	-34.28%	27.83%	-29.94%
30	Avg Cost Per Month for Meter Reading, Billing, Meters & Services		$ 18.14	$ 22.21	$ 82.58				$ 291.82

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Base Rates	Change	Proposed Base Rates
Residential Service Schedule 410		
$8.00 Customer Charge	$2.00/month	$10.00 Customer Charge
All Therms - $0.54073/Therm	$0.07824/therm	All Therms - $0.61897/Therm
General Service Schedule 420		
$14.00 Customer Charge	$6.00/month	$20.00 Customer Charge
All Therms - $0.43901/Therm	$0.07869/therm	All Therms - $0.51770/Therm
Large General Service Schedule 424		
$50.00 Customer Charge	$0.00/month	$50.00 Customer Charge
All Therms - $0.13887/Therm	-$0.01045/therm	All Therms - $0.12842/Therm
Interruptible Service Schedule 440		
All Therms - $0.11652/Therm	$0.00000/therm	All Therms - $0.11652/Therm
Seasonal Service Schedule 444		
All Therms - $0.17155/Therm	-$0.01201/therm	All Therms - $0.15954/Therm
Transportation Service Schedule 456		
$275.00 Customer Charge	$0.00/month	$275.00 Customer Charge
1st 10,000 Therms - $0.14978/Therm	-$0.01089/therm	1st 10,000 Therms - $0.13889/Therm
Next 20,000 Therms - $0.09014/Therm	-$0.00655/therm	Next 20,000 Therms - $0.08359/Therm
Next 20,000 Therms - $0.07409/Therm	-$0.00539/therm	Next 20,000 Therms - $0.06870/Therm
Next 200,000 Therms - $0.05799/Therm	-$0.00422/therm	Next 200,000 Therms - $0.05377/Therm
Over 250,000 Therms - $0.02942/Therm	-$0.00214/therm	Over 250,000 Therms - $0.02728/Therm

Schedule 456 Monthly Minimum Charge
18,750 @ $0.08359 = $1,567.31

CASE: UG 287
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Opening Testimony

July 31, 2015

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

A. My name is Judy Johnson. My business address is 201 High St. SE., Suite 100, Salem, Oregon 97301. I am employed as a Senior Economist.

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. I evaluate three areas of Cascade's rate request, information technology-related costs, pipeline safety cost recovery, and environmental remediation cost recovery.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1002, consisting of 1 page.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Information Technology

Q. Please explain what Cascade has in its rate case for Information Technology spending in 2015.

A. The Company showed in its response to Data Request No. 282, that it had added $1,164,009 to Intangible Plant for Information Technology spending in 2015. This figure is shown in Exhibit 1002, which is taken from Data Request 282.

Q. Does Staff agree with Cascade's projected spending for Information Technology?

A. No. The Company's response to Data Request 282 revealed that several of the projects were not going to be used and useful by the end of 2015. I have prepared an adjustment that removes from rate base $184,840, which is shown in Exhibit 1002.

//

Issue 2, Pipeline Safety Cost Recovery

Q. What is Cascade's position regarding Pipeline Safety Cost Recovery?

A. The Company would like to file annually, on the same timeline as its PGA, for recovery of costs associated with pipeline safety activities. Cascade would accumulate the costs through each PGA year and put into rates the revenue requirement of its annual investment.

Q. What is Staff's position?

A. In March 2015, the Commission opened a generic docket to investigate issues related to gas utilities' recovery of pipeline safety costs (Docket No. UM 1722).[1] Staff believes this issue is more appropriately reserved for the generic investigation. There is no revenue requirement effect as the Company is asking for this mechanism to begin in 2016. The rate case test period is 2015.

Regarding the merits of the Company's request, Staff's position is that if a gas utility can confidently project what will be spent on pipeline safety costs then the utility should incorporate those costs within a general rate case filing. Staff strongly believes that special cost-recovery mechanisms should be reserved for large unexpected multi-year costs.

Q. What are other gas utilities doing about gas pipeline safety costs?

A. NW Natural had a special mechanism for collecting pipeline safety costs.[2] That special mechanism was instituted because NW Natural had a stay-out of rate cases agreement and the new rules that came out on pipeline safety were going to result in large expenditures over multiple years. NW Natural asked for

[1] Order No. 15-093.
[2] Order No. 09-067.

a mechanism to provide some rate relief. Staff and other parties worked cooperatively with the Company to develop a mechanism.[3] It has expired, but NW Natural is working with all parties in the UM 1722 generic docket. Avista has not requested a special mechanism. Avista is coming in for annual rate cases and is getting its pipeline safety costs in rates through its rate cases.

//

[3] Order No. 09-067.

Issue 3, Environmental Remediation

Q. What is Cascade's position on recovery of environmental remediation costs?

A. Cascade has made an estimate of its environmental remediation costs and would like to amortize this estimated cost over three years. The annual amortization would equal $468,637 for three years.

Q. How did Cascade estimate its environmental remediation expense?

A. Cascade explains that its environmental remediation liability comes from a site in Eugene, Oregon, for which it shares cost responsibility with PacifiCorp and Eugene Water & Electric Board (EWEB).[4] The Department of Environmental Quality (DEQ) has issued a Record of Decision identifying the measures needed to remediate the site.[5] Cascade has a tentative agreement with PacifiCorp and EWEB regarding allocation of costs for these measures, and Cascade estimates that its allocation will likely be $1,736,300.[6] Cascade reports that it has deferred $228,224 in environmental remediation-related costs since 2012 and expects to receive $186,000 in insurance proceeds for defense costs over the next year.[7] Cascade asserts that when the $1,736,300 allocation and the $228,224 deferral are netted against the $186,000 in estimated insurance proceeds, the net balance is $1,405,911.[8] Staff calculates this number to be $1,322,076. Since Staff is suggesting a different

[4] CNG/300, Parvinen/25-26.
[5] CNG/300, Parvinen/26.
[6] CNG/300, Parvinen/26.
[7] CNG/300, Parvinen/26-27.
[8] CNG/300, Parvinen/26-27.

methodology for recovering remediation expenses this discrepancy can be handled by using actuals. However, for purposes of an adjustment, Staff will use the number the Company has used in its rate case.

Q. What is Staff's position?

A. Staff recommends that Cascade's remediation costs be handled similarly to how NW Natural's environmental costs were brought into rates. Although NW Natural's remediation costs are more extensive than Cascade's, one thing we have learned is that these types of costs are difficult to determine ahead of time. We also learned that insurance payments for remediation costs are also difficult to determine ahead of time. In fact, Cascade witness Parvinen states in his testimony: "The amount and timing of any insurance recoveries for remediation costs is speculative at this point in time."[9]

Staff recommends that base rates include a modest amount for environmental remediation of $100,000. To the extent Cascade incurs environmental remediation costs in excess of this amount, Cascade can defer those remediation costs. After the "excess" costs are examined for prudence, there should be an earnings test to determine whether the costs can be recovered in rates. Similarly, to the extent environmental remediation costs are less than the $100,000, any monies left over would be carried over to the following year. Insurance proceeds should also be deferred to allow the Commission the opportunity to determine how those proceeds should be used to offset environmental remediation costs. Once the prudence review and earnings

[9] CNG/300, Parvinen/27, lines 5-6.

review have taken place, the deferred amounts can be moved to an amortization account. That account should earn the same interest as NW Natural earns on its SRRM which is the five year Treasury rate plus 100 basis points..

Q. Does this conclude your testimony?

A. Yes.

//

CASE: UG 287
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualification Statement

July 31, 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 287
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

July 31, 2015

DR 282 - June 29, 2015 Exhibit 1002

Oregon portions as multipled by the 3-Factor Allocation percentage for 2015; updated with current forecasted spending estimates

Projects highlighted below are not slated to be used and useful at December 31, 2015

FERC	Project Description & Name	Completion Date (projects tend to have short-term continuing expenses)	Prior Spending	2015 Proforma (5 & 7) Forecasted Spending	2016	2017	2018	2019	Remove Projects Not Used & Useful
			Data						
subtotal_value_desc	fp_number		Sum of Prior	Sum of 2015	Sum of 2016	Sum of 2017	Sum of 2018	Sum of 2019	
3030-Misc. Intangible Plant									
	FP-101209 - Miscellaneous Intangible & Software	2015; continuous	5,337	34,453	0	0	0	0	
	FP-101472 - Work Management-GL Essentials	2017	171,290	81,099	47,324	61,265	0	0	-81,099
	FP-101479 - Mobile Workforce Management System	2017	0	22,580	10,502	49,886	0	0	-22,580
	FP-101481 - UG GPSLS PROJECT - SOFTWARE	2017	26,048	7,048	5,549	43,872	0	0	-7,048
	FP-101510 - Gas Management System	2015	285,025	70,094	0	0	0	0	
	FP-200028 - UG AUTO TEST CNG DIRECT	2015	6,406	168	0	0	0	0	
	FP-200064 - Customer Self-Service Web-based	2015 CNG	174,530	34,709	65,510	0	0	0	
	FP-200155 - UG GPSLS PROJECT - HARDWARE	2015	1,217	82	0	0	0	0	
	FP-200352 - Customer Care & Billing System	2015 CNG Live; upgrade 2016	4,431,415	469,065	262,555	0	0	0	
	FP-200378 - Mobile Workforce Management Direct	2015	611,804	7,313	0	0	0	0	
	FP-200663 - GIS Enhancements	In service; ongoing upgrades	43,840	126,671	171,261	53,529	15,753	15,753	
	FP-301811 - SCADA Enhancements	In service; ongoing upgrades	0	39,940	0	0	0	0	-39,940
	FP-301813 - SCADA Enhancements	In service; ongoing upgrades	0	53,681	30,959	11,372	12,131	13,005	
	FP-302579 - PII - Personal Info Security	2017	0	20,596	8,034	4,017	0	0	-20,596
	FP-302616 - Human Capital Management	done in phases which go live completed	13,191	17,348	14,124	0	0	0	
	FP-302621 - LV Customer Website	2015	6,334	2,181	0	0	0	0	
			0	0	0	0	0	0	
3030-Misc. Intangible Plant Total			5,776,436	987,029	615,819	223,940	27,885	28,758	-171,263
3913-CNG Servers and Workstation									
	FP-101478 - AUTOMATED VEHICLE LOCATION SYS	2015 Postponed	0	13,576	26,862	0	0	0	-13,576
	FP-200661 - DATA CENTER/NETWORKING EQUIP	2015; continuous	49,445	15,716	19,692	19,692	19,692	0	
	FP-200662 - PC SUPPORT EQUIPMENT	2015; continuous	84,837	91,160	45,947	45,947	45,947	0	
	FP-306967 - District Office Access Control Sys	2015	0	56,527	0	0	0	0	
3913-CNG Servers and Workstation Total			134,283	176,980	92,501	65,639	65,639	0	-13,576
Grand Total			**5,910,718**	**1,164,009**	**708,320**	**289,579**	**93,524**	**28,758**	**-184,840**

CASE: UG 287
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

July 31, 2015

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

A. My name is Ming Peng. My business address is 201 High St. SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. I am employed by the Public Utility Commission of Oregon (OPUC) as a Utility Analyst 3 in the Energy Division. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. I describe my analysis of depreciation expense and depreciation reserve (accumulated depreciation) in the Company's filing as documented by witness Parvinen in Exhibit No. CNG/300 of Cascade Gas - Montana-Dakota Utilities Co (CNG).

Q. How is your testimony organized?

A. My testimony is organized as follows:

<u>Issue 1, Analysis of Capital Recovery Parameters</u>

Q. What is depreciation?

A. Defined by the National Association of Regulatory Utility Commissioners (NARUC),

> <u>*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.*</u>[1]

Q. What is CNG's current depreciation rate and expense?

A. CNG currently uses an existing depreciation rate of 2.77 percent, or $20.5 million per year for total system.

Q. What depreciation rate and expense does CNG use in its Test Year revenue requirement?

CNG's proposed depreciation accrual rate is 3.04 percent, or $22.5 million per year for total system, and $473,415 per year for Oregon (22.74

[1] NARUC "Public Utility Depreciation Practices," p 318.

percent, Oregon Rate base Allocation).[2]

Q. What is CNG's proposed depreciation accrual rate based on?

A. On April 30, 2015, CNG filed with the Commission the results of a detailed depreciation study of all CNG's gas plant in service as of December 31, 2013 (the "Study").[3] The Study includes proposed depreciation lives, curves, and net salvage rates (collectively the "parameters") and depreciation rates for CNG's Transmission Plant, Distribution Plant, and General Plant, and Intangible Assets. CNG's proposed depreciation accrual rate is based on the results of the Study.

Q. Are you currently reviewing CNG's depreciation rates filing?

A. Yes. I am currently reviewing the Study filed by CNG, docketed as UM 1727.

Q. Will the investigation into CNG's depreciation rates be concluded before the rates filed in this docket go into effect?

A. Yes. The parties plan to participate in settlement meetings on August 18, and August 27, 2015. If the case is not settled, a hearing will be held on September 24 with a targeted date for a Commission Decision around October 29, 2015.

[2] CNG/workpapers Exhibits 301-304, Depreciation Expense Adj.
[3] UM 1727/Cascade Natural Gas Corporation Petition to File Depreciation Study at 2.

Q. What are the review procedures in UM 1727?

A. The review procedures include the selection of the capital recovery parameters of retirement dispersion, service life projections for the future, salvage, and cost of removal projections for the future. The depreciation expense is then calculated by using the Commission authorized depreciation rates in traditional FERC classification of generation, transmission, distribution and general plant assets.

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. Do Oregon Statutes address utility depreciation rates?

A. Yes. ORS 757.140, states:

> *(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 authorized depreciation rates in traditional FERC classification of generation, transmission, distribution and general plant assets. In this case, the depreciation rates will be determined in UM 1727. The new depreciation rates will be used in UG 287 rate case.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 287
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

July 31, 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 I have been employed by the Public Utility Commission of Oregon (OPUC) since January 1999, working in a wide area of topics and testifying in various formal state hearings, with my current responsibility focusing most on the review of energy utility depreciation rates.

CERTIFICATE OF SERVICE

UG 287

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 31st day of July, 2015 at Salem, Oregon

Kay Barnes

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Public Utility Commission
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UG 287

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