CNG/100
Madison

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

DIRECT TESTIONY OF Scott W. Madison
REPRESENTING CASCADE NATURAL GAS CORPORATION

Cascade and Rate Case Overview

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Scott W. Madison. My business address is 555 South Cole Road, Boise, ID 83709. My e-mail address is scott.madison@intgas.com.

Q. By whom are you employed and in what capacity?

A. I am employed by Cascade Natural Gas Corporation (Cascade or Company) and Intermountain Gas Company as Executive Vice President and General Manager.

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

A. Yes. I graduated from the University of Idaho with a Bachelor of Science degree in Accounting. I have participated in several executive education programs, including attending executive education at the Harvard Business School. I served as Vice President, Controller and Chief Accounting Officer for Intermountain Industries and each of its subsidiaries from 1997 to 2008. From 1987 to 1997 I was a Senior Manager with Arthur Andersen LLP.

I serve as a director of the Northwest Gas Association and the Western Energy Institute. I also serve as a director and a member of the Executive Committee of the Idaho Association of Commerce and Industry and the Boise Metro Chamber of Commerce. I am the past Chairman of the Board of Directors for the Better Business Bureau of Idaho and Treasurer of Idaho Ducks Unlimited.

I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Idaho Society of Certified Public Accountants.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. I will provide an overview of Cascade. I will also summarize the Company's rate request in this filing, the primary drivers for the need for rate relief, and provide some background on increasing costs facing the Company. My testimony will also describe measures the Company has taken to control costs and increase operating efficiencies in order to stay out of rate cases to date. I will also introduce the other witnesses providing testimony on the Company's behalf.

Q. Would you please summarize Cascade's requested increase in this filing?

A. Yes. Increasing rate base and operating expenses require Cascade to request an increase of $3,622,770 or 5.11%. This increase is based on an overall rate of return of 7.47% with a capital structure common equity component of 51% and a return on equity of 9.55%. The Company is using a forecasted test period of the calendar year 2015. The forecasted test period was selected as the most appropriate and supportable during the period rates will be in effect. Michael Parvinen provides further discussion of the test period in his testimony. The Company is using the results of a long-run incremental cost study as a starting point in the proposed spread of the requested increase to the various rate schedules. Ron Amen provides testimony supporting the cost study and rate spread issues.

Based on an average usage level of 55 therms per month, the average residential customer will see a bill increase of $1.88 per month from $54.03 to $55.91. This equates to an average increase of 3.48%.

III. OVERVIEW OF CASCADE

Q. Please briefly provide an overview of the Company.

A. Cascade provides natural gas distribution services in 96 communities in Washington and Oregon. Cascade's headquarters are located in Kennewick, Washington. Cascade is wholly owned by Montana Dakota Utilities Resources Group, Inc. (MDU Resources), located in Bismarck, North Dakota. Cascade has 272,884 customers, of which 68,337 are in Oregon. Although Cascade serves 25 communities in Oregon, the largest of those communities are Bend, Baker, and Pendleton.

Cascade was originally formed in 1953 to serve smaller communities in the Pacific Northwest. Cascade serves a non-contiguous service territory with 312 dedicated employees. Cascade became a subsidiary MDU Resources in 2007.

IV. REASONS FOR RATE INCREASE REQUEST

Q. What is the primary factor causing Cascade's request for a rate increase in this filing?

A. The primary factor is pipeline replacement costs. In 2011, as a requirement from the Department of Transportation, Cascade prepared a process for evaluating the physical condition of its distribution pipeline. Through the implementation of the evaluation process, Cascade identified a number of areas of concern that could eventually impact its ability to provide safe reliable service. As a result, Cascade has devoted a tremendous amount of capital to pipeline replacement and improvement projects over the last three years, and will continue to do so over at least the next five years to ensure the integrity of its system. As an example; Cascade acquired its Bend area in the 1950s. Although Bend has had substantial growth over the years, the pipeline system in the core of the city has remained virtually untouched since its acquisition in the 1950s. Cascade is currently entering year four of a multi-year plan to completely replace the original system. Cascade completed the first three years of the multi-year plan using funds from merger savings and other synergies it obtained in the acquisition by MDU Resources.

Q. How much has Cascade invested in the Bend area in just the last three years?

A. Cascade has invested nearly $12 million replacing its aging system in Bend, much of which is bare steel. Cascade is planning an additional $2.5 million of capital investment in Bend alone in 2015, which is included in this rate case. The budget projections for Bend for the 2016–2019 period include $2.6 million up to $3.3 million per year. Cascade will also be focusing on system improvement or replacement in its other communities in Oregon. Cascade's five-year capital budget includes system improvement or replacement costs of $3.9 million in 2015 and $8.0 to $12.6 million for each year during the 2016–2019 time period.

Q. Will this investment create a substantial amount of rate pressure in the years to come?

A. Yes. It will. Cascade anticipates that without the pipeline cost recovery mechanism (CRM), described by Mr. Parvinen, Cascade will be filing more frequent rate cases.

Q. How much of the current requested increase of $3.6 million is due to 2015 capital investments?

A. $2.3 million. This means that 63% of the increase is attributable to rate base increases.

Q. Please identify other drivers of the proposed increase.

A. Cascade is in the process of increasing its operating personnel in order to keep up with the demands associated with these pipeline system projects, increased pipeline safety regulations, and an increasing customer base. This accounts for an additional revenue need of $608,000. Other proposed increases, which are explained by Mr.

Parvinen, include depreciation expense in the amount of $487,000, environmental remediation in the amount of $482,000, and pension asset recovery in the amount of $368,000. These items total more than Cascade's requested increase but are the major reasons for the need to increase rates at this time.

Q. How has Cascade controlled costs in order to mitigate the need for rate cases?

A. Let me start by saying that Cascade's last filed general rate case in Oregon was in1988. The Commission Staff initiated a show cause case that resulted in a slight reduction in rates in 2007. Cascade has a history of mitigating increased cost pressures in order to avoid filing rate cases. Since the acquisition by MDU Resources, Cascade has found synergy savings in the form of joint senior management, a unified call center, joint billing facility and process, and uniform accounting and customer information system software. The utility group continues to look for ways to acquire such synergies including a new Gas Management System (GMS).

Cascade has performed an Administrative and General (A&G) expense study to evaluate not only how Cascade compares to its peers, but also how Cascade has been able to manage A&G costs over the years particularly since the acquisition. Mr. Chiles presents the results of the study.

V. CUSTOMER SUPPORT PROGRAMS

Q. Can you identify the customer support programs that Cascade provides for its customers in Oregon?

A. Cascade provides a number of programs to assist customers in meeting their energy bill obligations as well as conservation programs. Cascade has its Low Income Rate Assistance Program (LIRAP) and its Winter Helps program to provide bill assistance to low-income customers. Cascade also offers a budget payment plan to customers, which serves to levelize volatility in bill amounts associated with usage.

Cascade also provides conservation programs through the Energy Trust of Oregon, and provides conservation programs through community action agencies specifically for low-income customers.

Q. Please briefly describe the Budget Payment Plan.

A. The Budget Payment Plan is an option for customers to make a flat payment for a period of time thus flattening or levelizing their bill. The plan makes it easier for customers to budget their payments. Under the plan, winter bills will be lower than if billed based on actual usage, and summer bills will be higher than if billed based on actual usage. Once a year, the account will be reset based on the previous year's usage and residual balance.

Q. How well received is the Company's Budget Payment Plan?

A. As of December 31, 2014 there are 5,500 or 8.0% of Oregon customers participating in the Budget Payment Plan.

VI. OTHER COMPANY WITNESSES

Q. Would you please introduce and provide a brief description of each of the witnesses filing testimony on behalf of Cascade in this proceeding?

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

<u>Mr. Mark Chiles</u>, Vice President and Chief Accounting Officer – Western Region, will address the company's capital structure, the proposed cost of embedded debt, and the overall rate of return. He will also discuss the results of the A&G cost study to explain how Cascade's A&G costs compare to other companies as well as the annual verification of actual A&G costs compared to what costs may have looked like absent the acquisition by MDU Resources.

Mr. Michael Parvinen, Director – Regulatory Affairs, will discuss the overall revenue requirement, the Conservation Alliance Plan and decoupling, the proposed pipeline Cost Recovery Mechanism, the Environmental Remediation Recovery proposal, and also explain the Company's philosophy underlying its basic charge requests in this case.

Mr. Micah Robinson, Gas Supply and Regulatory Consultant at MRE Consulting, has been retained to present the forecasted customer and load determination used in 2015 Revenue Adjustment presented by Ms. Archer and Mr. Parvinen.

Mr. Ronald J. Amen, Director – Management Consulting at Black & Veatch, has been retained to prepare and present the Company's long-run incremental cost study for the Oregon service territory. Mr. Amen discusses his study results and how each schedule's present and proposed rate compares to the indicated cost.

Ms. Pamela Archer, Supervisor – Regulatory Analysis, discusses the base year revenue proof, 2015 proposed revenue adjustment, and the proposed tariff changes.

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

A. Yes.

CNG/200
Chiles

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

DIRECT TESTIMONY OF MARK A. CHILES
REPRESENTING CASCADE NATURAL GAS CORPORATION

Cost of Capital and A&G

I. INTRODUCTION

Q. Would you please state your name, business address and position?

A. Yes. My name is Mark A. Chiles and my business address is 8113 W Grandridge Blvd, Kennewick, WA 99336. I am the Vice President and Controller for Cascade Natural Gas Corporation (Cascade or Company), a wholly-owned subsidiary company of MDU Resources Group, Inc. (MDU Resources).

Q. Would you please describe your duties?

A. As Vice President and Controller, I am responsible for providing leadership and management of the accounting, treasury, and planning functions for Cascade, including the preparation of financial reports and compliance with Sarbanes-Oxley.

Q. Would you please outline your educational and professional background?

A. I graduated from Boise State University with a Bachelor of Business Administration degree in Accounting. I am a certified public accountant and a member of the American Institute of Certified Public Accountants and the Idaho Society of Certified Public Accountants. I have over 20 years of experience in the energy industry including time spent in the utility, gas marketing, and exploration and production industries. During my utility career, I have held the positions of Financial Reporting Accountant, Director of Accounting and Finance, and Vice President and Controller.

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

A. The purpose of my testimony is threefold: first, to explain and support the capital structure and rate of return requested in this proceeding; second, to summarize and support the reasonableness of Cascade's administrative and general expenses; and third, to explain and support the allocation of intercompany charges between Cascade and related entities.

Q. Please summarize your testimony.

A. In brief, I will provide information that shows:

- Cascade's proposed rate of return (ROR) of 7.47% provides a reasonable return for our investors at a fair cost to our customers. The ROR is based on a 51.0 percent common equity ratio with a Return on Equity (ROE) of 9.55% and a debt cost of 5.30%.
- Cascade has followed through on the commitment made in Order No. 07-221 that "the allocated shared corporate costs, as well as its allocated and assigned utility division costs, will not exceed the costs the Cascade customers would otherwise have paid absent the acquisition, as adjusted for changes in the Consumer Price Index."[1] Moreover, Cascade's administrative and general expense levels are well within reason when compared to other regulated companies.
- The intercompany allocations between Cascade and affiliated companies provide necessary services to Cascade customers at costs equal to or lower than if Cascade either performed the services themselves or contracted for the services with non-affiliated companies. These services include, but are not limited to, executive oversight, customer billing, payment collection and processing, accounts payable processing, information technology support, and customer service support.

[1] *In the Matter of MDU Resources Group, Inc. Application for Authorization to Acquire Cascade Natural Gas Corporation*, Docket UM 1283, Order No. 07-221, Attachment A at 16 (June 5, 2007).

II. RATE OF RETURN AND CAPITAL STRUCTURE

Q. What is the rate of return and capital structure that Cascade is requesting in this case?

A. The Company is requesting a rate of return of 7.47% with a capital structure of 51% equity and 49% debt. The components and calculation of the proposed rate of return are shown in Table 1.

Table 1. Proposed Rate of Return

	Capital Structure	Cost	Component
Common Equity	51%	9.55%	4.87%
Total Debt	49%	5.30%	2.60%
	100%		7.47%

Q. The Company is proposing a capital structure of 51% equity and 49% debt. Why does the Company feel this is the appropriate capital structure?

A. The requested capital structure is based upon Cascade's actual capital structure for the last four years. The Company is committed to maintaining a healthy capital ratio which we believe is in the best interests of our shareholders and customers.

Cascade believes this capital structure is reasonable. Table 2 provides a summary of the four year history of Cascade's capital structure.

Table 2. Capital Structure

	12/31/2011	12/31/2012	12/31/2013	12/31/2014
Total Debt	48.9%	45.9%	51.7%	49.3%
Common Equity	51.1%	54.1%	48.3%	50.7%

Q. Why is the Company proposing a 9.55% return on equity?

A. The Company believes that a ROE of 9.55% represents a fair return for both shareholders and customers.

Q. How did you calculate the cost of debt proposed in this filing?

A. The 5.30% cost of debt is calculated based on the weighted average outstanding debt at December 31, 2014 plus additional borrowing that occurred in January 2015. The January 2015 borrowing was part of a term loan agreement that closed on November 24, 2014.

Q. Will any of the debt included in this filing come due within the next five years?

A. No, attached as confidential Exhibit Cascade/201, page 1, is a schedule showing the current outstanding debt with maturity dates.

Q. Does Cascade plan to issue any equity or debt offerings in the near future?

A. The equity or debt issuances planned for the next five years are provided in confidential Exhibit Cascade/201, page 2.

III. ADMINISTRATIVE AND GENERAL COSTS

Q. As a condition of the acquisition of Cascade by MDU Resources, Cascade committed that "for Oregon regulatory purposes, that commencing with the closing of the Transaction and through December 31, 2012, the allocated shared corporate costs, as well as its allocated and assigned utility division costs, will not exceed the costs the Cascade customers would otherwise have paid absent the acquisition, as adjusted for changes in the Consumer Price Index."[2] Has the Company complied with this commitment through December 31, 2012?

A. Yes. As provided in section (a) of Commitment 10, compliance is determined through comparison with a 2005 Benchmark adjusted annually by the increase in the Consumer Price Index (CPI).[3] The Company has stayed under the threshold for A&G costs as adjusted for changes in the CPI. Cascade files an annual earnings report with the Public Utility Commission of Oregon (Commission) showing the calculation of actual A&G expense compared to the 2005 benchmark as adjusted for the CPI. A summary of the annual filings is included as Exhibit Cascade/202.

Q. Part of the commitment Cascade made in the acquisition agreement is that Cascade would not shift A&G costs to operational and maintenance (O&M) accounts, capital accounts, deferred debit accounts, deferred credit accounts, or other regulatory accounts that are the basis for ratemaking. Can you

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[2] *In the Matter of MDU Resources Group, Inc. Application for Authorization to Acquire Cascade Natural Gas Corporation*, Docket UM 1283, Order No. 07-221, Attachment A at 16 (June 5, 2007).
[3] *Id.*

confirm that A&G costs have not been shifted to O&M accounts, capital accounts, deferred debit accounts, deferred credit accounts, or other regulatory accounts that are the basis for ratemaking?

A. Yes. I can confirm that we have not reclassified A&G costs to other accounts.

Q. How do Cascade's A&G costs compare to those of the other regional natural gas utilities?

A. Cascade had a study prepared, the results of which are included as Exhibit Cascade/ 203, which shows that Cascade compares very favorably in regards to A&G costs versus other utilities. Exhibit Cascade/203, page 1, provides 2013 A&G expense per customer compared to all U.S. gas companies separated by jurisdiction. That exhibit shows that Cascade's A&G expense in Oregon of $75.05 per customer on an annual basis is below the median A&G expense by $28.99 or 28%, and below the mean A&G expense by $62.29 or 45%. On a regional level, Exhibit Cascade/203, page 2, shows that Cascade's A&G expense for Oregon is under the median A&G expense of $79.00 per customer by 5%.

Q. How do Cascade's A&G costs compare to those of other natural gas utilities in Oregon?

A. The data from the study shows that in the state of Oregon, Cascade has the lowest A&G cost per customer for 2013 for natural gas utilities.

Q. What has been the recent history of Cascade's A&G costs?

A. Exhibit Cascade/203, page 5, shows that from 2009 to 2013 Cascade has seen an overall steady decrease in the total company A&G expense per customer in Oregon. In 2010 there was a significant increase in A&G cost per customer, but this was due in large part to the transition of the corporate office from Seattle to Kennewick. The downward trend of A&G cost per customer is being driven by lower overall A&G costs coupled with an increase in our customer base. In 2014 Cascade's A&G cost per customer increased as a result of higher A&G salaries, lower returns on retirement plan investments, and higher regulatory costs.

Q. Has Cascade taken specific measures to control A&G costs since the acquisition?

A. Yes, as part of the acquisition of Cascade and of Intermountain Gas Company, the Company, as part of the MDU Utility Group, has gone through a process of identifying areas where we might gain efficiencies and therefore save costs. Specifically, we identified the areas of customer service and information technology as groups where the individual company employees could be integrated into one group resulting in less cost for each of the utility brands. Prior to the acquisition, Cascade had multiple sites for their customer service personnel. The utility group now has two customer service sites that provide service for all of the utility brands. In addition, the IT group has been integrated into one company in order to reduce duplication and promote efficiencies in the companies.

Q. Now that the customer service and IT employees have been integrated into single groups, who do they work for and how are their costs allocated?

A. All customer service and IT employees are now technically employed by MDU Utility Group. The allocation of expenses between the companies is explained in the following section describing intercompany allocations.

Q. Can you point to any other drivers of the Company's ability to contain A&G costs?

A. Yes. The Company has seen a 4.6% increase in customer growth over a five year period, which results in a lower cost-per-customer.

IV. INTERCOMPANY ALLOCATIONS

Q. Please provide an overview of Cascade's intercompany allocations.

A. Cascade receives intercompany allocations from its parent company, MDU Resources, which includes the utility company referred to as Montana-Dakota Utilities. Cascade also receives intercompany allocations from Intermountain Gas Company (Intermountain), another wholly-owned subsidiary of MDU Resources. The intercompany allocations include, but are not limited to, charges for board and executive oversight, legal and accounting services, the use of office facilities and equipment, processing of payroll, accounts payable, customer billing and payment collection, information technology support, and customer service support.

Q. Are there agreements in place between the related parties that describe the services to be provided and how the charges will be allocated between the related parties?

A. Yes, when MDU Resources purchased Cascade, MDU Resources and Cascade agreed to comply with all Commission statutes, rules, and ordering conditions concerning affiliated interest filings. This included an Intercompany Administrative Services Agreement (IASA). The IASA was filed with the Commission with an effective date of July 2, 2007 and, with the purchase of Intermountain, an amended IASA was filed with the Commission with an effective date of March 18, 2009.

Q. What is the basis for the allocation of expenses charged to and from Cascade?

A. Per the IASA, expenses can be charged based on direct assignment, service charges, or allocations. Charges for services performed specifically for Cascade are "directly assigned." For example, we directly assign charges to Cascade for legal services that our corporate legal group performs for the Cascade only. We assess a "service charge" to Cascade for services of general applicability to the utility group—such as when our corporate legal group performs work that benefits all of the utilities.

Finally, we assess an “allocation” for services performed for the corporation as a whole-- such as when our legal group performs work that benefits all of the business units within MDU Resources.

Q. How often is the corporation allocation methodology reviewed?

A. The methodology for the allocation of charges for certain corporate functions such as payroll and accounts payable processing, procurement, information technology services, and finance and administration are updated annually. Confidential Exhibit Cascade/204 shows the cost allocation basis for charges in calendar year 2014.

Q. What is the process for billing intercompany charges?

A. Each month allocable costs are compiled by each of the companies as part of the accounting close process. An invoice is prepared detailing the charges so that the receiving company has adequate information to appropriately code the charges. The invoices are due for payment upon receipt. Intercompany invoices received by Cascade are analyzed for the appropriateness of the charges by accounting personnel. Any questions are reconciled with the issuing company.

Q. Who is responsible for keeping a record of the charges?

A. Per the IASA, the issuing party is responsible for maintaining the support for the charges. All parties are responsible for providing access to the records and for maintaining such records in accordance with good record management practices.

Q. Does this conclude your testimony?

A. Yes.

CNG/201
Chiles

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MARK A. CHILES

Confidential Exhibit No. 201

(PROVIDED ON CD)

Long-Term Debt / Equity and Debt Issuance

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MARK A. CHILES
Exhibit No. 202

A&G Expense

Cascade Natural Gas Corporation
UM 1283 A&G Expense Adjustment
State of Oregon

	2007	2008	2009	2010	2011	2012	2013
2005 A&G Benchmark (per UM-1283)	$ 6,848,545	$ 6,848,545	$ 6,848,545	$ 6,848,545	$ 6,848,545	$ 6,848,545	$ 6,848,545
CPI Increase	7.15%	11.26%	10.87%	12.69%	16.24%	18.65%	20.38%
Annual A&G Benchmark	$ 7,338,154	$ 7,619,691	$ 7,592,780	$ 7,717,305	$ 7,960,749	$ 8,125,600	$ 8,244,620
Cascade Actual A&G Expense	$ 7,349,106	$ 6,522,058	$ 6,606,891	$ 7,494,560	$ 6,672,809	$ 6,236,397	$ 5,311,406
A&G Type 1 adjustments	$ (769,091)	$ (112,175)	$ (117,570)	$ (114,513)	$ (5,906)	$ (209,722)	$ 223,129
Cascade Adjusted A&G Expense	$ 6,580,015	$ 6,409,884	$ 6,489,321	$ 7,380,047	$ 6,666,903	$ 6,026,674	$ 5,534,534
Below Threshold (Yes/No)	YES	YES	YES	YES	YES	YES	YES
A&G Adjustment (if below threshold then no adjustment)	$ -	$ -	$ -	$ -	$ -	$ -	$ -

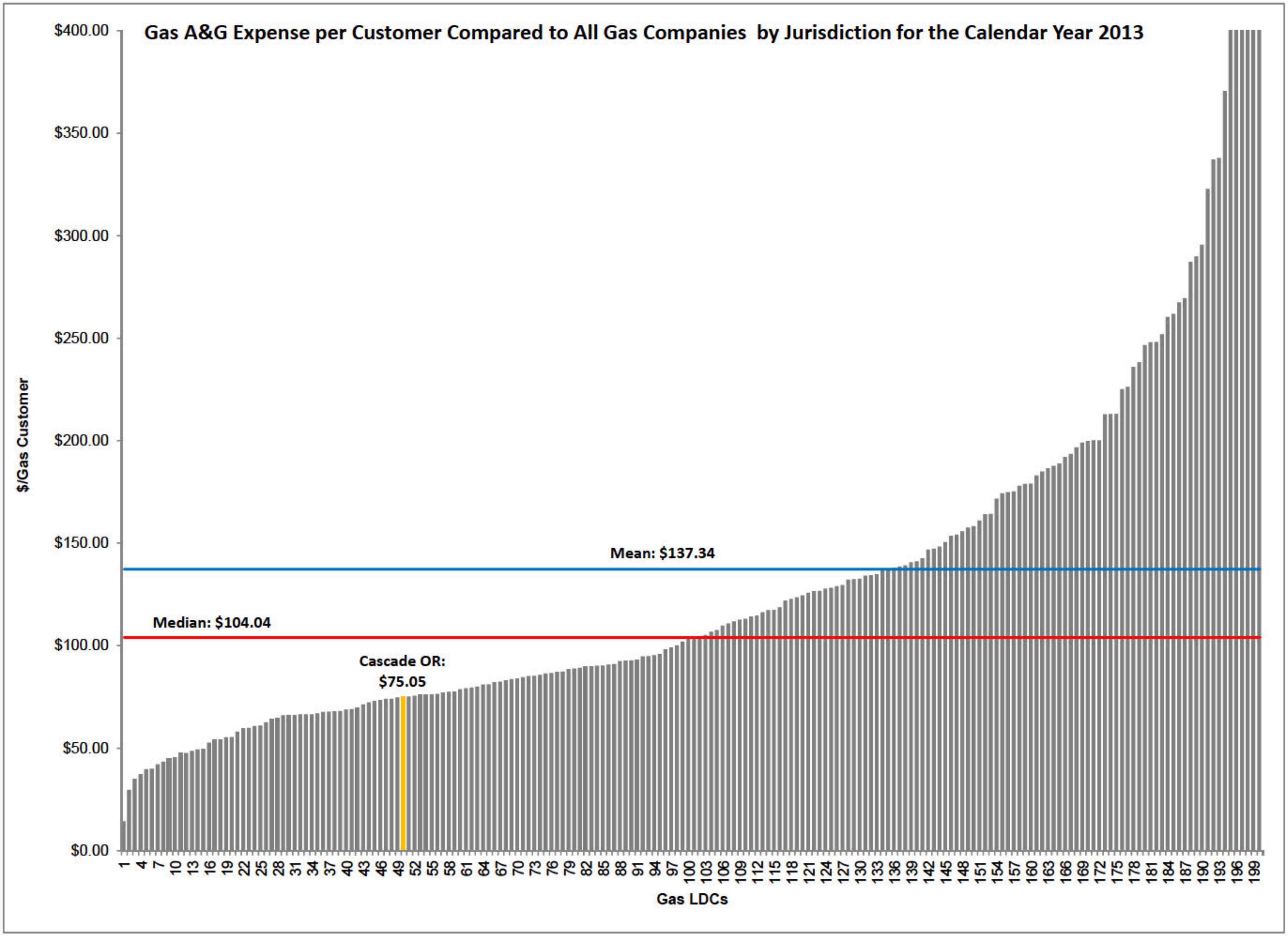
BEFORE THE

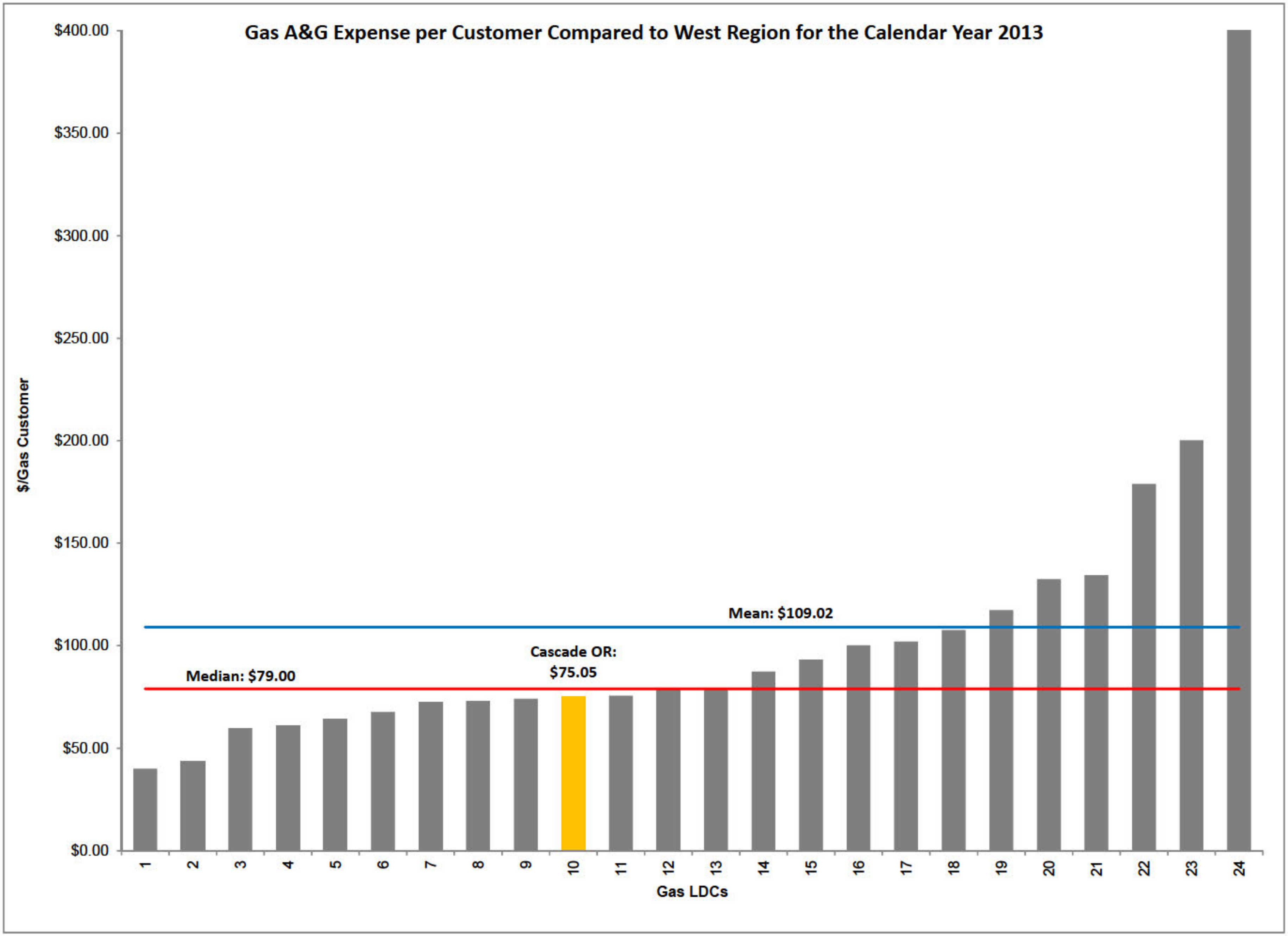
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MARK A. CHILES
Exhibit No. 203

A&G Expense per Customer


Gas A&G Expense per Customer Compared to All Gas Companies by Jurisdiction for the Calendar Year 2013
$/Gas Customer
$400.00
$350.00
$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$0.00
Mean: $137.34
Median: $104.04
Cascade OR:
$75.05
Gas LDCs


Gas A&G Expense per Customer Compared to West Region for the Calendar Year 2013
$/Gas Customer
$400.00
$350.00
$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$0.00
Mean: $109.02
Cascade OR:
$75.05
Median: $79.00
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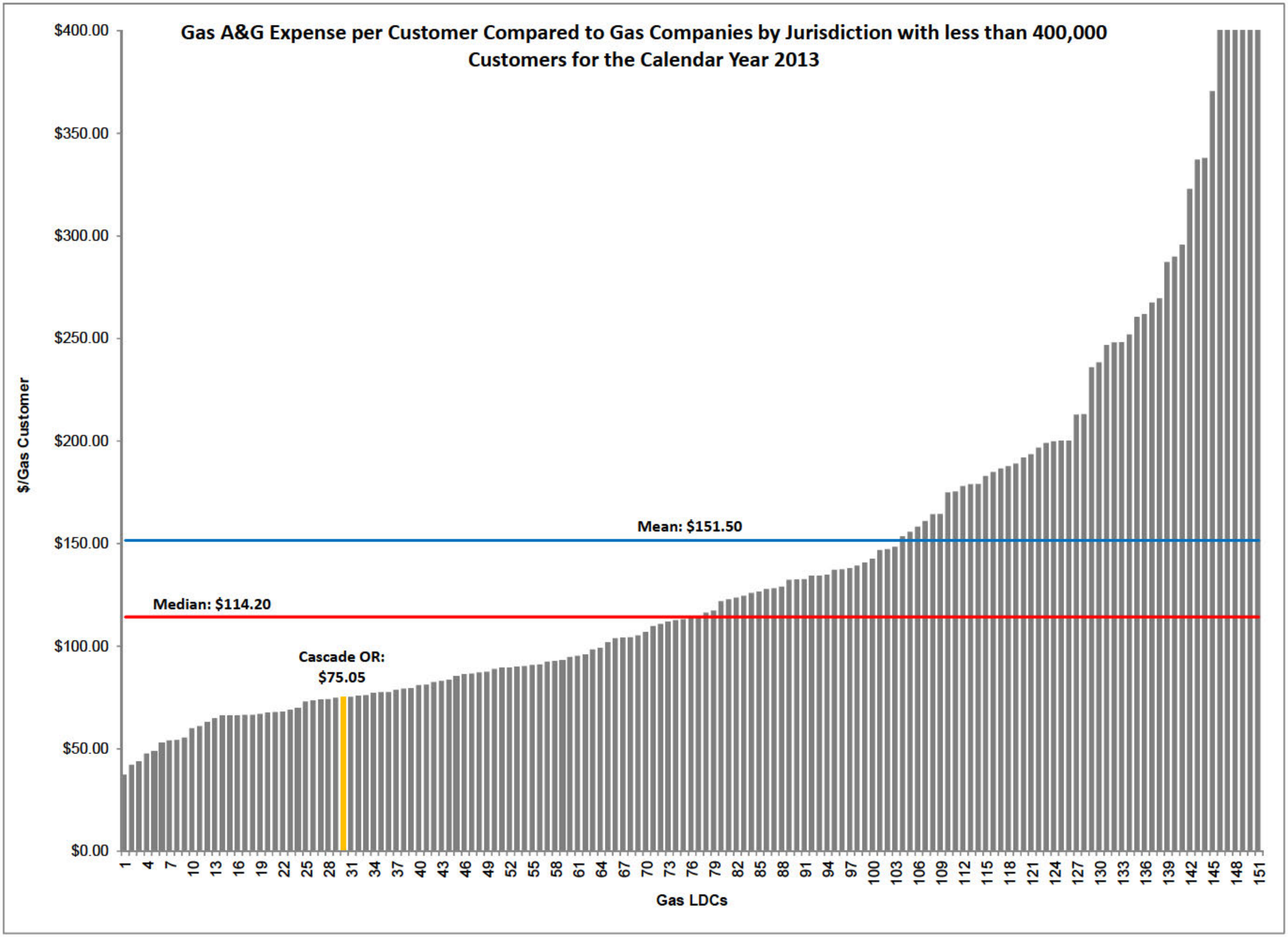
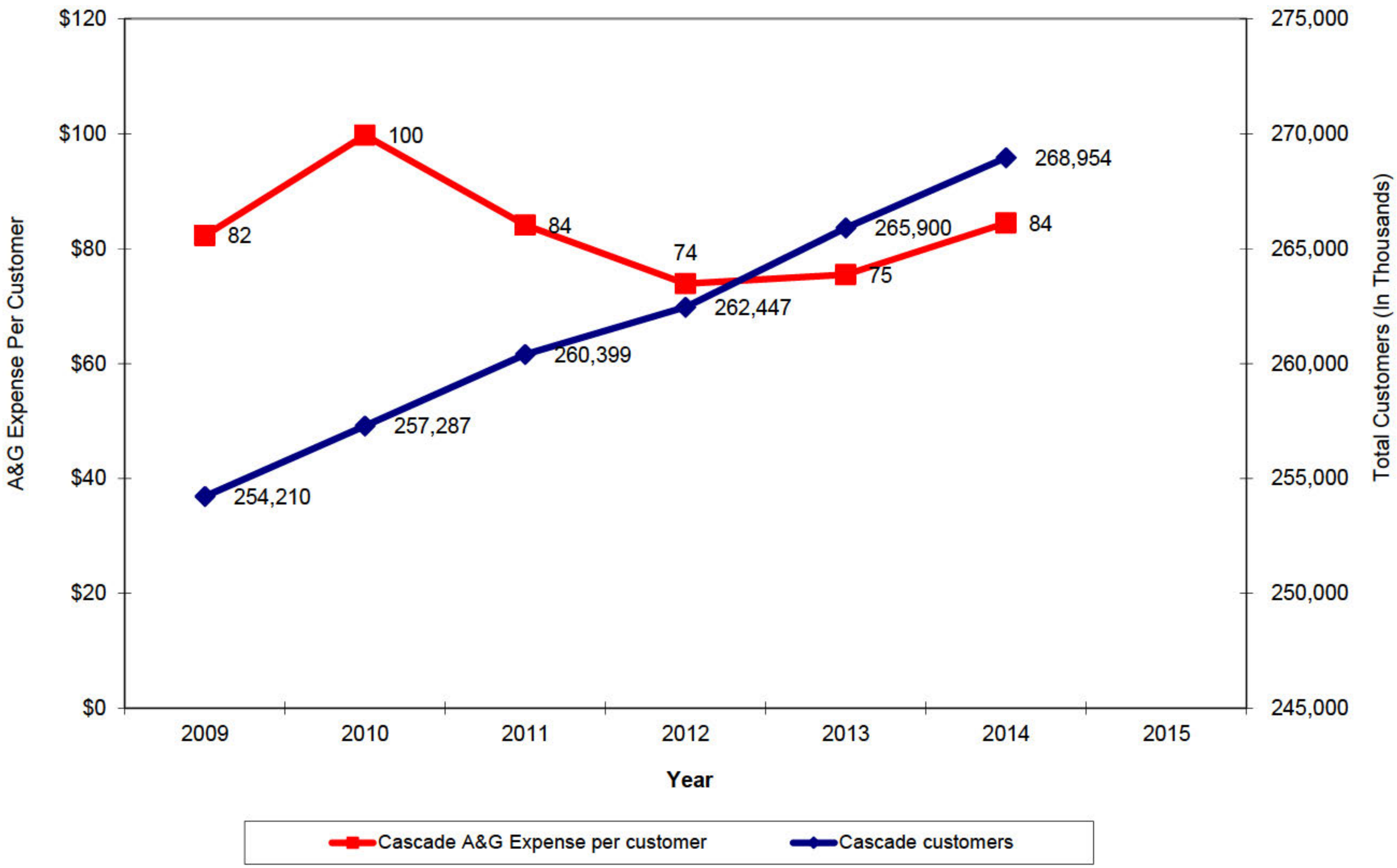
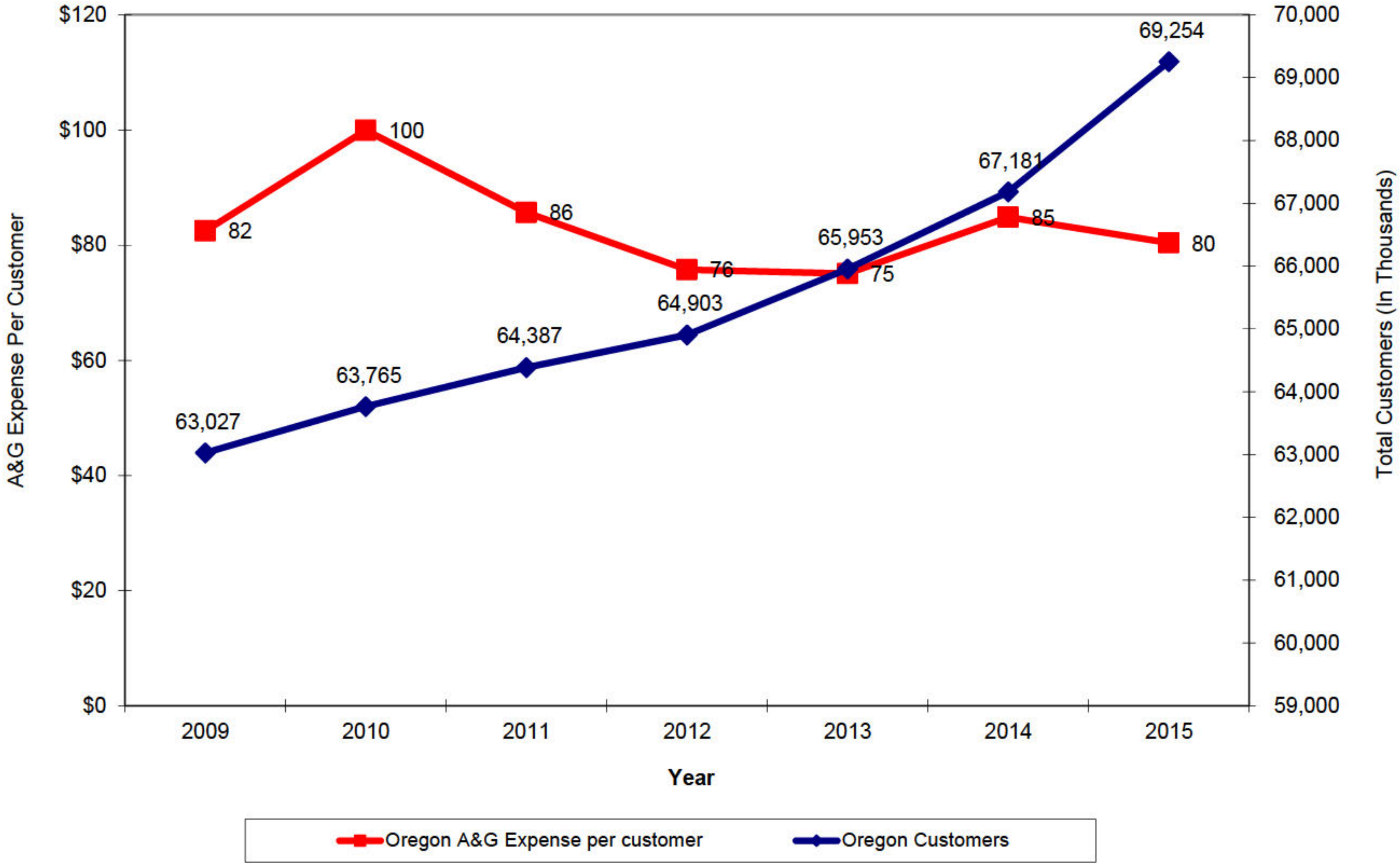
Gas LDCs


Gas A&G Expense per Customer Compared to Gas Companies by Jurisdiction with less than 400,000 Customers for the Calendar Year 2013
$/Gas Customer
$400.00
$350.00
$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$0.00
Mean: $151.50
Median: $114.20
Cascade OR:
$75.05
Gas LDCs

Cascade Natural Gas Corporation
A&G Expense Per Customer and Customer Count Trends
For the Calendar Years 2009 - 2014



Cascade Natural Gas Corporation - Oregon
A&G Expense Per Customer and Customer Count Trends
For the Calendar Years 2009 - Test Year 2015



BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MARK A. CHILES
Confidential Exhibit No. 204
(PROVIDED ON CD)

Pricing Methodology

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

DIRECT TESTIONY OF MICHAEL P. PARVINEN
REPRESENTING CASCADE NATURAL GAS CORPORATION

Revenue Requirement

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael P. Parvinen. My business address is 8113 W. Grandridge Blvd., Kennewick, Washington 99336-7166. My e-mail address is michael.parvinen@cngc.com.

Q. By whom are you employed and in what capacity?

A. I am employed by Cascade Natural Gas Corporation (Cascade or Company) as the Director of Regulatory Affairs. In this capacity, I am responsible for the management of all economic regulatory functions at the Company.

Q. How long have you been employed by Cascade?

A. I have been employed by Cascade since September 2011. Prior to joining Cascade I was employed by the Washington Utilities and Transportation Commission (WUTC) for nearly 25 years. I was employed as a Regulatory Analyst, later as a Deputy Assistant Director, and lastly as the Assistant Director of the Energy Section.

Q. What are your educational and professional qualifications?

A. I graduated from Montana College of Mineral Science and Technology in May of 1986, with a Bachelor of Science degree in Business Administration with an emphasis in accounting.

I have testified before the Public Utility Commission of Oregon (Commission) on behalf of Cascade in dockets UG 224 and UM 1633. I have also testified numerous times before the WUTC.

I have also analyzed or assisted in the analyses of numerous other utility rate filings, and participated in many utility rulemaking proceedings before the WUTC. Finally, I attended the Seventh Annual Western Utility Rate Seminar in 1987 and the 1988 Annual Regulatory Studies Program, sponsored by the National Association of Regulatory Utility Commissioners.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. My testimony will cover five primary areas. First, I will address the revenue requirements and supporting calculations. Next, I'll describe the current Conservation Alliance Plan (CAP) including the decoupling mechanism as well as proposed changes to the mechanism. Third, I will describe Cascade's proposed recovery of Environmental Remediation costs. The fourth section will describe Cascade's proposed pipeline recovery mechanism. In the last section I will present Cascade's approach to its proposed basic charges for residential and commercial customers.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits, which are described in my testimony:

Exhibit CNG/301	Results of Operation Summary Sheet
Exhibit CNG/302	Revenue Requirement Calculation
Exhibit CNG/303	Conversion Factor Calculation
Exhibit CNG/304	Proposed Adjustments to Base Year Results
Exhibit CNG/305	Independent Evaluator's Report (without appendices)
Exhibit CNG/306	Summary of Decoupling Mechanism
Exhibit CNG/307	Monthly Calculation of Decoupling Deferral Entries
Exhibit CNG/308	Decoupling Allowed Margin per Customer
Exhibit CNG/309	Record of Decision (ROD)
Exhibit CNG/310	Calculation of Environmental Remediation Proposal
Exhibit CNG/311	Pipeline Recovery Mechanism Sample Calculation

III. REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

Q. Please summarize the results of the proposed revenue requirements for the Oregon jurisdiction.

A. After taking into account all proposed adjustments, the forecasted rate of return (ROR) is 5.00%, as shown in Exhibit CNG/301. The incremental revenue necessary to achieve the recommended ROR of 7.47% is $3,622,770, also shown in Exhibit CNG/301. The calculation of the incremental revenue is also provided in Exhibit CNG/302. The overall base revenue increase requested is 5.11%.

Q. Please describe the contents of Exhibit CNG/301.

A. The figures shown in column (1) are the actual Oregon booked figures for the base year, which is the twelve months ended December 31, 2014. Column (2) is the summation of all adjustments, both restating and forecasted, to achieve the test period results. Each adjustment that is included in column (2) is identified separately in Exhibit CNG/304, and will be described later in my testimony. Column (3) is the sum of columns (1) and (2) and represents the expected results of operations in the test period absent any rate change. Column (4) identifies the proposed revenue change and the net income impact of the revenue increase. The proposed revenue increase is also calculated in Exhibit CNG/302. Column (5) is the results of operation expected during the test period with proposed rates.

Q. What is the Company's proposed test year for this case?

A. Cascade is proposing calendar year 2015 as the test period. As a practical matter, rates are anticipated to go into effect approximately February 1, 2016; consequently, 2016 will be the first year rates will be in effect. However, we have been working on our revenue requirement studies for many months now, and at the time we conducted our analysis, we were unable to project 2016 revenues and costs with any accuracy.

Q. Does the Company anticipate adjusting the test period later in this docket?

A. No. Although costs are anticipated to exceed growth in revenues from new customers in 2016, in order to keep the current filing as simple as possible, Cascade is not proposing to include such projections.

Q. Are 2016 revenue increases due to increased customers expected to offset 2016 expected cost increases?

A. No. If margin revenue increased by 1%—which is a reasonable expectation—the increase in margin revenue would be approximately $300,000. A typical wage increase of 3% would offset half that amount while a simple inflation calculation would offset the remaining half. For this reason the selection of a 2015 test year yields conservative results.

Q. Please describe the contents of Exhibit CNG/302.

A. Exhibit CNG/302 shows the calculation of the proposed revenue increase of $3,622,770 necessary to achieve the proposed rate of return of 7.47%.

Q. Would you please describe Exhibit CNG/303?

A. Exhibit CNG/303 shows the calculation of the conversion factor which is applied to the required net income to produce the required revenue increase. The conversion factor takes into account revenue-sensitive items that change as revenue changes, including uncollectibles, franchise taxes, Commission fees, Oregon state income tax, and federal income taxes. The conversion factor is calculated to be .58346.

Q. Please describe Exhibit CNG/304.

A. Exhibit CNG/304 shows each of the Company proposed adjustments culminating in a total column shown on page 2, column (v). The total column is also shown in Exhibit CNG/301, column (2).

Q. Would you describe each of the adjustments included in Exhibit CNG/304?

A. Yes. The first column, column (a), entitled "Uncollectibles Expense" is an adjustment to test period booked uncollectibles expense to the average of the last three years of actual bad debt write-offs. This adjustment is consistent with the Type I adjustment in Cascade's annual earnings report. The result is a decrease in net income of $167,504.

Column (b), entitled "Removal 25% Membership Fees" adjusts 25% of booked membership fees consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $2,191.

Column (c), entitled "Officer Incentive Com. Adj" removes all incentive compensation paid to the executive group. This adjustment is also consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $81,145.

Column (d), entitled "Promotional Advertising Adjustment" removes all base year advertising booked to FERC account 913. This adjustment is consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $303.

Column (e), entitled "Interest Coordination Adjustment" adjusts federal income tax for the effect of the average debt rate used to calculate the rate of return applied to the proposed rate base shown in Exhibit CNG/301, column (3), line 27. This adjustment is again consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $33,808.

Column (f), entitled "PGA Sharing Adj." adjusts revenues to reflect the amount of Purchase Gas Adjustment (PGA) commodity sharing that was accrued during the base year. Cascade is increasing earnings to reflect additional gas costs absorbed by the Company of $385,502 during 2014 as a result of commodity costs being greater than those built into the PGA. The result of this adjustment is an increase in net operating income of $224,920.

Column (g), entitled "Annualizing Wage Rate Adjustment" reflects the full year impact of the union contract wage increase that was effective April 1, 2014. This adjustment reduces net income by $15,046.

Column (h), entitled "Removal of Retiree Medical Credits" removes miscellaneous credits associated with retiree medical costs. This adjustment increases net income by $16,862.

Column (i), entitled "2015 Revenue Adjustment" adds margin revenue to account for the additional weather normalized load to be added during 2015. This adjustment increases net income by $246,295.

Column (j), entitled "2015 Wage Adjustment" reflects the wage adjustment applied to non-union and union employees. Non-union wage increases are effective January 1 and union increases effective April 1. The current union contract expires March 31, 2015, so the April 1 increase is not known yet. Cascade is proposing 3.5% as a placeholder to be updated later in the docket. This adjustment decreases net income by $105,339.

Column (k), entitled "Pension Asset Adjustment" places into rate base the level of prepaid pension asset, net of deferred taxes, per the position of the Joint Utilities[1] in docket UM 1633, which has not been resolved at the time of this filing. The rate base effect of this adjustment is an increase in rate base of $2,873,126.

Column (l), entitled "Pipeline Inspection Cost Adj" adjusts for increased costs associated with additional pipeline inspections over and above those already performed on an annual basis. These inspections will include digging in various

[1] The "Joint Utilities" in docket UM 1633 are Cascade, Avista Corp., Northwest Natural Gas, Natural, PacifiCorp dba Pacific Power, and Portland General Electric.

locations to physically examine the condition of the distribution system. It is anticipated that these additional costs will continue for several years. The net effect of this adjustment is a decrease on net income of $205,548.

Column (m), entitled "Labor Additions Adjustment" reflects additions to labor expenses for employees that have been and or are planned to be added during 2015. The Company is anticipating a net gain of 15 additional positions in 2015 on a system basis. The majority of these positions are for district office personnel required to manage the workload associated with the increased investment in replacing the most at-risk portions of the distribution system. Two positions are being added to create a more dynamic safety program and provide better training options for our field personnel. One position is being added to the regulatory department based on increased workload anticipating perpetual rate cases. Another position is added in Gas Supply and one in Procurement for inventory control. We expect that all of these positions will be filled prior to the rate effective date. The net effect of this adjustment is a decrease on net income of $354,733.

Column (n), entitled "Public Purpose Cost Reallocation" removes from expenses the portion of costs provided to the Energy Trust of Oregon (ETO) in addition to funds collected from the Public Purpose Charge (PPC). Currently, additional funds are provided to the ETO in an amount not less than $500,000 per year consistent with the Commission's order in docket UG 167.[2]

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[2] *In the Matter of Cascade Natural Gas Corporation Request for Authorization to Establish a Decoupling Mechanism and Approval of Tariff Sheets No. 30 and No. 30-A*, Docket UG 167, Order No. 06-191 at 3 (Apr. 19, 2006).

Q. Did the Commission's order in docket UG 167 specify how the additional $500,000 contribution would be funded?

A. Order No. 06-191, which adopted the parties' stipulation, stated that "Cascade agreed to contribute 0.75 percent of its revenues from Rate Schedules 101 and 104, but no less than $500,000 per year, for public purposes, the funds to be distributed to the ETO and community service agencies for DSM and low-income assistance programs."[3]

Q. Did the Commission later approve a stipulation clarifying the ratemaking treatment of the $500,000 contribution for earnings review?

A. Yes, the stipulation in docket UG 173 clarified that the public purposes funding provided by Cascade under that provision would be reflected as an operating expense for ratemaking and future revenue sharing purposes.[4] The parties further clarified the ratemaking treatment in docket UM 1283—the investigation into the MDU Resources Group, Inc. (MDU Resources) acquisition of Cascade. In the stipulation adopted by the Commission in that matter, the Company expressly pledged to contribute funding, until September 30, 2012, to the Energy Trust of Oregon and community service agencies in the manner prescribed docket UE 167, conditioned upon such funding being included as a cost of service for ratemaking and revenue sharing purposes.[5] This commitment was later extended to December 31, 2015 in a stipulation approved by the Commission in Order No. 13-079.[6]

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[3] *Id.*
[4] *In the Matter of the Staff Investigation into the Earnings of Cascade Natural Gas Corporation*, Docket UG 173, Order No. 07-220, App. A at 3 (June 5, 2007).
[5] *In the Matter of MDU Resources Group, Inc., Application for Authorization to Acquire Cascade Natural Gas Corp*., Docket UM 1283, Order No. 07-221, Ex. 1, p. 10 (June 5, 2007).
[6] *In the Matter of Cascade Natural Gas Corporation, Motion to Amend Order No. 07-221 regarding Company's Decoupling Mechanism*, Docket UG 224, Order No. 13-079 (Mar. 13, 2013).

Q. Is the Company now proposing to collect the $500,000 contribution through the PPC?

A. Yes. The Company is proposing to remove that amount from general expenses and include the $500,000 in the PPC.

Q. Why is this change appropriate?

A. Moving the $500,000 public purpose fund contribution into the PPC will provide better information to our customers about the amount that they are paying for conservation and low-income programs. This change will have a net zero impact to customers. The net effect of this adjustment is an increase in net income of $150,436. The PPC rates will also be adjusted at the same time as general rates in order to maintain the amount of funds provided to the ETO.

Q. Why is the adjustment not $500,000?

A. Cascade verifies every year in December that $500,000 is being provided to the ETO for this component, however Cascade also uses accrual accounting and in December 2013 a much larger amount had to be accrued for, thus resulting in a large reversal of that amount in January 2014. The December 2014 accrual was much smaller than December 2013.

Q. Are there other issues that arise from a decision to collect through the PPC the $500,000 previously provided through operating expenses?

A. Yes. Currently the PPC is collected from Schedules 101 and 104 (residential and commercial customers) only, to provide programs to these customer groups. The additional $500,000 provided to the ETO from operating expenses is used to provide conservation programs to industrial and large usage core customers (Schedules 105 and 111). So, with the shift of the amounts in general expenses to the PPC, the Company is proposing to include Schedules 105 and 111 in the PPC tariff (Schedule

31) to continue providing cost effective conservation programs through the ETO for all core customers.

Q. Will you please continue describing each of the adjustments in Exhibit CNG/304?

A. Yes. Column (o), entitled "2015 Plant Additions" reflects the Company's budgeted level of capital additions expected to go into service during 2015. The majority of the projected investment is related to non-revenue producing investment. The Company will update this projection later in the case to reflect actual costs and more up-to-date estimates. The net income effect of the rate base additions, for depreciation expense and property taxes, is a decrease of $448,699. The rate base impact is an increase of $11,745,699.

Column (p), entitled "Reallocation of A&G Charges" moves certain charges historically booked to an Administrative and General (A&G) account to a different location. First, we have moved billing-related costs including postage and bill printing costs to Customer Accounts. In addition, we have moved costs related to performance of atmospheric corrosion studies from A&G expenses to Operating and Maintenance (O&M) expense, where they are more appropriately booked. The surveys will be an ongoing expense item. There is no net income impact of these adjustments.

Q. If there is no net income impact of this adjustment, what is the purpose of proposing the adjustment?

A. As explained by Mark Chiles, Cascade has sponsored a study to compare how the Company's A&G costs compare to the A&G costs incurred by other natural gas companies. Properly allocating all customer-related costs to Customer Accounts results in a more accurate comparison. Notably, even though Cascade compares favorably to the other natural gas companies in the study, there were items that incorrectly affected the 2014 balances as reflected in Exhibit CNG/203. Cascade has made the changes to its accounting system to properly book these costs starting in 2015.

Q. Please continue with the remaining adjustments shown in Exhibit CNG/304.

A. Column (q), entitled “Rate Case Costs” reflects the impacts of incremental costs associated with filing this general rate case. These costs will be updated later in the case as they become known and better estimated. The net income impact is a decrease of $111,877.

Column (r), entitled “Inflation Factor” reflects the impact of applying a consumer price index inflation factor to non-labor related expenses. The net income effect is a decrease of $96,140.

Column (s), entitled “Depreciation Expense” shows the impact of the depreciation study expected to be filed in April 2015. The net income effect is a decrease of $284,333.

Column (t), entitled “Employee Incentive Plan Adj” reflects the Commission’s practice regarding incentive plans in which amounts associated with earnings are removed and components associated with customer service and expense targets are removed at 50%.

Q. Can you describe briefly what Cascade’s incentive plan is?

A. Yes. Cascade’s plan consists typically of three components; the director level plan in 2014 was comprised of four components. The first component is based on achieving financial targets or net income levels. The second and third component is based on reduced spending and customer satisfaction goals. The fourth goal, for directors only, is based on a review of Company safety policies with employees during the year. Each component is worth an equal portion of the incentive payment.

Q. What is the impact of this adjustment?

A. Cascade had a total of $168,156 of incentive payments allocated to Oregon. $112,104 is being removed to comply with the Commission's standing policy. The net income impact is an increase in net income of $67,330. For simplicity Cascade did not allocate between the adjustment between directors and other salaried personnel. Having done so would reduce the effects of the adjustment.

Q. Please describe the last adjustment in Exhibit CNG/304.

A. Column (u), entitled "Environmental Remediation" shows the impact of Cascade's proposal regarding environmental remediation costs for the Eugene Remediation Site. Further discussion of the proposal can be found later in my testimony. The net income effect is a decrease of $281,463.

Q. What is the net impact of all the proposed adjustments to the base year results?

A. As shown in column (v), line 22, the net income impact of all proposed adjustments is a reduction of $1,247,391 and a rate base increase of $14,618,825. Column (v) is carried forward into column (2) of the summary Exhibit CNG/301.

IV. CONSERVATION ALLIANCE PLAN & DECOUPLING

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

A. I will provide background on Cascade's current Conservation Alliance Plan (CAP) including the Decoupling mechanism and conservation/low-income funding through the PPC, a description of how the current mechanism is calculated and a description of the PPC. I will address recommendations from the third-party evaluator's report included as Exhibit CNG/305. Finally, I will describe Cascade's proposed changes to continue the CAP.

Q. What is the CAP?

A. The CAP is a comprehensive mechanism that encourages conservation and protects the Company from the adverse earnings impact from loss of load associated with weather and conservation. The Decoupling component of the CAP maintains a margin per customer recovery despite the effects of weather and conservation. The PPC component collects funds from customers receiving service under Schedules 101 (residential) and 104 (commercial) to provide funding for the conservation measures, as well as low-income conservation and bill assistance. The conservation program is administered by the ETO.

Q. Would you please describe the distinction between the terms CAP and Decoupling?

A. These terms are usually used synonymously. However, there is a distinction in regards to Cascade's mechanism; the CAP refers to the complete mechanism including Decoupling, conservation programs, PPC, and the true-up mechanism. Decoupling is a major component within the CAP. The Decoupling component in particular breaks the link between revenues and usage.

Q. Please provide a brief history of the current CAP, including the Decoupling mechanism, from its inception in 2006.

A. Cascade first applied for the CAP on October 17, 2005 in docket UG 167. The parties held several workshops and settlement discussions, which ultimately led to a settlement filed on April 14, 2006. The Commission approved the settlement by Order No. 06-191, with the tariff sheets to become effective May 1, 2006.

In addition to recommending approval of the CAP, some of the key elements of the settlement were:

- A termination date of September 30, 2010, prior to which Cascade would sponsor an independent evaluation of the CAP.

- Establishment of the PPC rate to collect funds from customers receiving service under Schedules 101 and 104 to provide funding for conservation programs administered by the ETO, including a portion of which to be distributed to community service agencies to administer for low-income conservation and bill assistance programs.
- Established that, in addition to the PPC, the Company provide funding for additional conservation measures in the amount of 0.75% of current revenues from Schedules 101 and 104, but no less than $500,000 per year.
- Established Service Quality Measures.
- Established an Earnings Sharing Mechanism.
- Agreement that the Company would file a general rate case in the first quarter of 2008 if requested by the Commission.

Q. Have any changes been made to the CAP since it was approved?

A. On June 5, 2007, the Commission entered Order No. 07-221, approving a settlement and authorizing the acquisition of Cascade by MDU Resources, which included modifications to the CAP. Also on June 5, 2007, the Commission entered Order No. 07-220 approving a settlement resolving the Staff investigation into Cascade's earnings. The following changes were made to the existing CAP:

- Extended the termination date to September 30, 2012, subject to changes resulting from the independent evaluation.
- Confirmed that the 0.75% of current revenue provided by Cascade for additional conservation measures is considered an above-the-line expense item for ratemaking and revenue-sharing purposes.[7]

[7] Order No. 07-220, App. A at 3 ("The parties agree that the public purposes funding provided by Cascade under paragraph 10 of the UG 167 Stipulation, or any other amounts for such purposes as ay be required in the future, shall be reflected as an operating expense for ratemaking and revenue sharing purposes.")

- Adjusted the equity rate for Earnings Sharing. (This component was later modified per Commission order in UM 1286.)
- Removed the rights of settling parties to request the Commission to require Cascade to file a 2008 general rate case.

Q. Were there any additional changes?

A. Yes. In docket UG 224, Order No. 13-079, the Commission accepted a settlement to modify the expiration date of the CAP to December 31, 2015, and required Cascade to file a general rate case by March 31, 2015.

Q. Was an independent evaluation of the CAP performed per the initial agreement?

A. Yes. Cascade contracted with Black & Veatch who performed the evaluation which was submitted to the Commission in docket UG 167 on April 30, 2010 (Evaluator's Report or Report). I have included a copy of the Evaluator's Report as Exhibit CNG/305 for reference and convenience

Q. Have any of the recommendations from the Evaluator's Report been implemented to date?

A. No, they have not. However, I am addressing each of the seven recommendations in this section.

Q. What is the first recommendation?

A. The first recommendation is to make the CAP permanent, which Cascade is proposing to do in this filing.

Q. What is the second recommendation?

A. The second recommendation is to review and update the use per Heating Degree Day (HDD) factors utilized in the Company's weather normalization equation and factors in its next rate case.

Q. Is Cascade implementing this recommendation in this case?

A. Yes. Cascade is using a 60 HDD as a better fit than the historical 65 HDD. Cascade is also using the most recent five years to determine the relationship between actual usage and HDD. Micah Robinson provides additional testimony on these topics.

Q. What is the third recommendation?

A. The third recommendation is to eliminate the use of unbilled volumes in the monthly decoupling adjustment. Cascade will do so going forward.

Q. What do you foresee as the impact of this recommendation?

A. Overall implementation of this recommendation should have no impact. On a monthly basis it could shift impacts from one month to another but as long as the method (either including or excluding unbilled volumes) is consistently applied there should be no impact to the results on an annual basis.

Q. What is the fourth recommendation?

A. The fourth recommendation is to analyze Schedule 104 to determine whether the class should be broken into two classes for purposes of obtaining more homogeneous load and cost characteristics. Cascade has analyzed this issue and recommends continuing with the existing class determination.

Q. What is the fifth recommendation?

A. The fifth recommendation is to consider real-time recovery of the weather-related component of the CAP.

As I explain below, Cascade has considered the recommendation and has determined that it should not be implemented. As discussed further below, Cascade is proposing to remove the breakout between weather and conservation impacts as the past results have produced convoluted information. A real-time adjustment would also add a layer of complexity to the monthly filings and added monthly review time by staff for what Cascade views as very limited benefit.

Q. What is the sixth recommendation?

A. The sixth recommendation is to target low-income customers to reduce the average use per customer. Cascade has implemented a pilot program called the Conservation Achievement Tariff (CAT) with the intent to remove barriers and increase funding to increase the number of low-income households being weatherized.

Q. What is the seventh recommendation?

The seventh and last recommendation is to consider a Straight Fixed Variable rate design as an alternative to decoupling. For the reasons I will discuss later in my testimony, Cascade is not supporting such an approach in this case.

Q. Would you please provide a brief explanation of how the Decoupling mechanism works?

A. Yes. The purpose of the Decoupling mechanism is to track and allow recovery of the commodity margin revenue differences occurring from both weather and conservation. Rates are revised annually to reflect changes in both (1) the margin differences between weather-normalized allowed margin per customer (baseline) and the actual use margin collected per customer and (2) the baseline normalized use established in the Company's most recent rate case adjusted to reflect conservation impacts.

Q. Has the CAP mechanism provided value to Cascade?

A. Yes it has. Even though the overall result has been a refund to customers, the Company has benefited by minimizing the swings in earnings as a result of the change in loads associated with weather and conservation.

Q. Does the CAP mechanism insulate the Company from the volatility associated with weather?

A. Yes, that is one of the component factors. It also insulates customers from the volatility of weather swings. For example, in the case of a colder than normal year, the CAP mechanism lowers rates for customers.

Q. Have you prepared an exhibit summarizing the Decoupling and baseline rate adjustment components?

A. Yes, Exhibit CNG/306. Line 3 shows the yearly effect of the Decoupling calculation for weather and conservation with column (k) showing the cumulative effect. Line 4 shows the annual impact of adjusting the base for effects of conservation. Line 5 shows the overall impact that the CAP mechanism has had on customers since the inception of the program through the end of 2014.

Q. What has been the overall impact of Decoupling on customers since the inception of the CAP mechanism?

A. As shown on line 5 of Exhibit CNG/306, customers have seen net rate reductions equal to $1,566,340.78.

Q. Can you explain why the figures on line 4 don’t begin until column (d)?

A. It is my understanding that the 2009/2010 PGA was the first time the base rates were adjusted to reflect the annual margin changes due to conservation based on weather-normalized volumes. The figure in column (d) of $1,013,535.00 was a cumulative change.

Q. Have you prepared an exhibit detailing each month's calculation of the Decoupling deferral entries?

A. Yes. I have provided Exhibit CNG/307, showing the calculations for each month for the 12 months ended June 30, 2014. As can be seen from this exhibit, the totals shown on page 3, lines 110, 111 and 112 (column N) correspond to the figures on Exhibit CNG/306, column (i), lines 1, 2 and 3. I provide further explanation of these exhibits in the next section of my testimony.

Q. Can you please describe Exhibit CNG/307?

A. Yes. The exhibit contains the Company's actual monthly calculations for the Decoupling portion of the CAP mechanism. This exhibit shows the last full 12 month period incurred, through June 30, 2014. The first page shows the monthly Decoupling calculation for residential customers under Schedule 101 by weather data location. Cascade has three weather data areas in its service territory in Oregon. The second page is for commercial customers under Schedule 104 for the same weather data locations. The third page is a summary page including the monthly book entries.

Q. Does Exhibit CNG/307 provide the total monthly deferral amount?

A. Yes, on page 1, the calculation on lines 38-43 (with the total shown on line 51) provides the total monthly deferral amount. This calculation shows the allowed margin to be recovered and then compares that to the actual margin revenue collected. The difference is the total monthly deferral. The remainder of the page shows the calculations to divide the monthly deferral between weather-related volume changes and conservation-related volume changes.

Q. Referring to page 1 of Exhibit CNG/307, please describe the remainder of the information on the page.

A. Lines 14 through 35 and then line 44 through 50 are calculations to allocate the monthly total into the weather and conservation related components based on variation from normal degree days and application of a coefficient factor, as established in the PGA process.

Q. Please explain page 2 of Exhibit CNG/307.

A. These are the same calculations shown on page 1 except they are based on data for our commercial customers. Again the important calculation is the total monthly deferral, which is derived by taking the allowed margin recovery (lines 90 – 92) and subtracting the actual monthly margin as calculated on lines 94 and 95. The result is shown on line 103.

Q. Please continue with an explanation of page 3 of Exhibit CNG/307.

A. Page 3 is a summary of pages 1 and 2 and also includes the actual book entry for the Decoupling component of the CAP mechanism.

Q. Turning now to Exhibit CNG/306, can you please explain this exhibit and the source of each figure?

A. This exhibit shows the annual effect of the Decoupling mechanism, including the change of the baseline calculation, as it has been or will be passed through to customers.

Line 1 is the total of the weather component for each year the CAP mechanism has been in effect. As an example, the figure in column (i) comes from Exhibit CNG/307, page 3, column N, line 110.

Line 2 is the annual conservation component, which for the twelve months ended June 30, 2014, comes from Exhibit CNG/307, page 3, column N, line 111.

Line 3 is the total, with column (k) showing the effect the Decoupling mechanism has had on customers since the inception of the mechanism.

Q. Does the ($3,523,828.78) figure in column (k), line 3, indicate that customers have been refunded this amount since 2006 due to the CAP mechanism?

A. Yes, with the exception of column (j). Column (j) will be included in the PGA filings that will become effective November 1 of 2015. Customers paid more margin per customer than was established as the base. Therefore, an overall refund was given based on the monthly CAP calculations. Because base rates are adjusted upward for the ongoing effects of conservation (line 4) the overall net impact of Decoupling on customers over the entire period has been a refund of $1,566,340.78 as shown on line 5.

Q. Referring to line 2, can you explain why several figures on this line, including the total, have credit balances or negative numbers for the conservation component?

A. Intuitively, the conservation component should always produce a positive number. That is, as customers implement conservation measures their usage should go down. Thus, reduced usage would result in a positive number or deferral. This isn't always the case and I believe it is mostly due to the breakdown of the total into weather and conservation components. The CAP mechanism starts with the difference between an allowed margin per customer and the actual margin collected from customers. This total difference is what the CAP mechanism is intended to calculate. However, the total is then broken into weather and conservation driven components. Since the weather component is calculated first and the remainder is attributed to conservation, I would venture to say that due to all the variables associated with weather within any given month (such as humidity, daily temperature fluctuations, inter-day fluctuations, etc.), the weather effects swamp the effects of conservation, thus creating conservation totals that create negative balances for the conservation component.

Q. Did the independent evaluator address this phenomenon?

A. Yes. The Report did identify several possible explanations but did not draw a solid explanation or conclusion. These explanations are included on pages 3-3 and 3-4 of the evaluator's report, Exhibit CNG/305 at 19-20.

Q. Does this phenomenon expose a fatal flaw in the CAP mechanism?

A. No, not at all. Overall, the CAP mechanism does exactly what it is intended to do. The CAP mechanism adjusts for the difference between allowed margin per customer and actual margin per customer. It is only when trying to split the amount between weather and conservation that we sometimes see a value that does not make intuitive sense.

Q. Is Cascade proposing a change to the CAP mechanism to fix this concern or phenomenon?

A. Yes. Cascade is proposing to only defer the difference between the allowed margin per customer compared to actual margin per customer and not split the deferral between weather and conservation. This would substantially reduce the amount of review of the deferral balances and convoluted calculation that go into the monthly weather and conservation splits.

Q. Turning back to Exhibit CNG/306, please continue with the explanation of line 4.

A. Line 4 shows the annual adjustment to base margin rates to reflect the impact of conservation. This adjustment is included in the annual PGA and is calculated by taking the average number of customers in the two classes, residential and commercial, multiplied by the authorized margin per customer to equal the total authorized margin revenue. The total authorized margin revenue is then divided by the current weather-normalized volume to determine the new base rate to obtain the same margin per customer as originally authorized.

Q. What would the result be if this adjustment were not made annually?

A. Theoretically, if the adjustment were not made annually, the deferral would have a cumulative effect. For example, if none of the adjustments had been made, the 2015 deferral would be at least $1.96 million higher than it otherwise will be due to the cumulative effect of conservation.

Q. Does this explain why the first year this adjustment was made, in 2009, it was significantly greater than any of the other years?

A. Yes. The 2009 adjustment reflects the effects of conservation on base usage since the CAP mechanism was first put in place.

Q. Where do the funds used for conservation for Cascade customers come from?

A. They come from two sources: the PPC, which is collected from residential and commercial customers under Schedule 31, and from a percentage of revenue that is recorded as an expense item on the Company's books.

Q. Can you provide some background on the PPC and how it got to the point it is today?

A. Yes. As described earlier in my testimony, a PPC charge was originally set to collect 0.75% of current revenues from customers on Schedules 101 and 104. It is my understanding that, in the early years while programs were ramping up, it was difficult to spend even that amount, so a deferral account was established to track the revenue and the spending. As the programs became more established and spending became more predictable, the deferral account became simply another funding source. In other words, the ETO had available funds collected through the PPC up to the authorized deferral level as well as the funds recorded or booked as an expense. Today the deferral component has been eliminated and the Company must work more closely with the ETO to properly match the PPC with the ETO's actual expenditures.

Q. The PPC originally was established at 0.75% of revenue. What is the charge today?

A. The PPC for customers on Schedule 31 is set at 1.85% and it is anticipated that the rate will need to be adjusted later in 2015 based on the 2016 ETO budgeted level of conservation for Cascade's customers.

Q. You mentioned another 0.75% of current revenues being provided by the Company. Can you explain this amount?

A. This payment was a condition of approval that Cascade agreed to in the original CAP settlement. In order to receive approval of the CAP mechanism, the Company agreed to provide the additional funding thus reducing earnings.

Q. Is Cascade proposing to continue this funding?

A. Cascade is proposing in this case to remove the component from general expenses and include the corresponding amount of funding directly in Schedule 31 (Public Purpose Charge) so that customers will be more readily aware of what they are actually paying in the way of conservation. This was described in greater detail earlier in my testimony.

Q. Can you summarize what Cascade is proposing in this filing regarding changes to the CAP, decoupling, and funding?

A. Yes. Cascade is proposing to continue with the CAP and decoupling. Cascade is only proposing to eliminate the split of the monthly deferral between weather and conservation as the results are not very meaningful. Cascade is proposing to continue funding the conservation programs with the PPC, including adding the current $500,000 from expense account 908 to the PPC. This shift will require all core customers, excluding interruptible Schedule 170, to participate in the PPC since those same core customers participate in the conservation programs.

Q. If all customers are participating in the conservation programs, is Cascade proposing a change to the monthly decoupling deferral entry to expand beyond Schedules 101 and 104?

A. Not at this time. Cascade has not performed an analysis to examine the effects of including Schedules 105 or 111 in the decoupling deferral. Cascade may evaluate the option at some future time.

Q. Have you prepared an exhibit showing the allowed margin per customer as determined from Cascade's proposed revenue, customers, and volumes?

A. Yes, Exhibit CNG/308.

Q. Please describe Exhibit CNG/308 and how it will be used after the conclusion of this docket?

A. The monthly average margin per customer shown on this exhibit will be applied to actual customers to derive the allowed revenue per customer to be collected. The difference from the allowed revenue and actual revenue charged to customers will be deferred.

V. ENVIRONMENTAL REMEDIATION COST RECOVERY

Q. Please provide a brief history of the Eugene Remediation Site and process.

A. The Manufactured Gas Plant (MGP) in Eugene, Oregon was first constructed in 1906 and operated as a coal carbonization process facility from 1907 – 1910. In 1910-1911 the plant expanded and was converted to a water-gas processing facility. On January 1, 1929, a PacifiCorp predecessor sold the MGP and underlying property to Northwest Cities Gas Company (Northwest Cities). In 1950, Northwest Cities ceased MGP gas operation and the plant was converted for propane-air gas storage and distribution. On October 12, 1953, Cascade merged with Northwest Cities. In

1958, Cascade sold the MGP and property to a predecessor of Northwest Natural Gas. The Eugene Water & Electric Board (EWEB) purchased the property in 1976.

Since discovery of the site conditions, EWEB participated with Oregon Department of Environmental Quality (DEQ) oversight to perform initial studies and to determine cleanup project objectives. The initial site investigation was completed in October 1995; the results from the initial site investigation demonstrated the need for additional assessment.

On February 26, 1996, EWEB, PacifiCorp, and Cascade entered into a participation agreement for site investigation. The participation agreement included a tentative cost sharing agreement under which Cascade is responsible for a portion of all investigation and remedial design costs. In January of 2015 the DEQ issued a Record of Decision (ROD) identifying the measures to remediate the site. A copy of the ROD is included as Exhibit CNG/309.

Q. Now that the ROD has been issued, has Cascade determined the cost to remediate the site including the anticipated remediation time period?

A. Yes. Cascade's anticipated portion will likely be approximately $1,736,300.

Q. Has Cascade deferred any costs associated with the Eugene remediation site?

A. Yes. Even though the parties started work evaluating the site starting back in 1996, Cascade did not request an order of deferral until it anticipated that the ROD was nearing execution. Cascade started deferring external costs under docket UM 1636 on December 1, 2012. Prior to December 1, 2012, any cost incurred was expensed.

Q. Does Cascade anticipate insurance recovery for any deferred and projected costs associated with the environmental remediation?

A. Yes. Over the next year, Cascade anticipates a total of approximately $186,000 in insurance proceeds for "defense costs." Defense costs in this context refer to those costs that the Company incurs to investigate the site—and the Company expects that it will recover the majority of those incurred. Roughly, all costs incurred by the Company in the first half of 2014 are defense costs.

Cascade anticipates that costs incurred in the second half of 2014 and beyond will be associated with actual remediation efforts, which includes planning and implementation of actual remediation. The amount and timing of any insurance recoveries for remediation costs is speculative at this point in time.

Q. What does Cascade propose for rate recovery of the Eugene Remediation Site in this docket?

A. Cascade proposes to include in rates the total expected cost of remediation plus the deferral balance as of December 31, 2014, less expected insurance proceeds divided by the three year remediation period which equates to $468,637.

Q. Has Cascade developed an exhibit detailing the calculation as proposed?

A. Yes. Confidential Exhibit CNG/310 shows the anticipated costs and Cascade's portion of those costs by year. Also included in the exhibit is the total amount deferred through 2014 in the amount of $228,224. Insurance proceeds are deducted from the total thus creating a net balance of $1,405,911 to be recovered over three years.

Q. During any of the three years in which Cascade deferred costs, was Cascade in an earnings sharing position?

A. No. Per each of the annual earnings reports submitted to the Commission for 2012-2014 Cascade has not been in an earnings sharing position.

Q. Will there be ongoing costs associated with the Eugene Remediation Site and how is Cascade proposing to treat those?

A. There will be ongoing costs. However, none are included in the proposed recovery calculation. Any ongoing costs will be included in actual results in the future to be evaluated for recovery as any ongoing expense in the future. These ongoing costs are difficult to determine at this point until the remedial design is complete.

VI. PIPELINE COST RECOVERY MECHANISM (CRM)

Q. Can you describe the purpose of Cascade's proposed Pipeline Cost Recovery Mechanism (CRM)?

A. Yes. The proposed CRM is a mechanism that provides timely recovery of costs incurred to promote the safety and reliability of Cascade's distribution system. The Company is using its Distribution Integrity Management Plan (DIMP) and model to identify and replace certain areas of the distribution system that are at elevated risks.

Q. Why is Cascade incurring these types of costs?

A. There are many portions of Cascade's system that include what is deemed as high risk pipe. Cascade is serious about its obligation to provide safe, reliable service to its customers, and to that end, Cascade is using a systematic approach to identify the highest risk areas and replace those sections of pipe.

Q. Are the costs associated with these projects revenue producing?

A. No. These are replacement costs with no new revenue associated with them. In other words, performing these system improvements increases costs and reduces earnings.

Q. Has Cascade been incurring these types of investments over the last several years?

A. Yes. Cascade has invested a significant amount over the last three years in replacing its infrastructure. In particular, Cascade has been focusing on the Bend area and systematically replacing the system in that area. Each year of replacement is considered a "Phase"; 2015 will be Phase 4. Cascade has spent a total amount of nearly $12 million in Phases 1 through 3.

Q. How has Cascade been able to incur these costs without rate recovery to date?

A. Cascade has used the efficiency gains from the MDU acquisition to fund these improvements. However, rate base and other costs increases have reached the point that Cascade is seeking this current rate increase request along with the proposed recovery mechanism.

Q. What are the benefits to customers if the Commission approves this mechanism?

A. Besides the obvious safer and more reliable system, the mechanism will potentially reduce the need for back to back rate cases. It will encourage the Company to control costs between rate cases and reduce the need for incurring additional rate case costs.

Q. Without the proposed mechanism what will be the impact on rate payers and the Company?

A. The Company believes that it is prudent and necessary to provide a safe reliable system, and believes these investments are required to do so. Without approval of the CRM, Cascade may be in a position in which it files for rate increases until such time as the DIMP modeling indicates an acceptable level of a risk profile is attained.

Q. Can you please describe how the mechanism is proposed to work?

A. Yes. Cascade proposes to file for recovery of its annual investment concurrently with its annual PGA filings on August 1 with an effective date of November 1. The August 1 filing will request recovery of investment from September 1 of the previous year until August 30 of the current year. For September through June we will have actual costs, and July and August will be projected. Cascade will file an update concurrently with the PGA update on September 15 which will then include actual investments through August 31 of the current year. All investments will therefore be in service at the time of final review.

Q. When will the first filing take place and will it cover a full year?

A. The current general rate case filing is proposing to recover investments through the end of 2015; therefore, to prevent double recovery, the first proposed filing will cover investments made after January 1, 2016, through August 31, 2016.

Q. Have you prepared an exhibit demonstrating how the mechanism would work?

A. Yes, Exhibit CNG/311.

Q. Please describe Exhibit CNG/311.

A. Exhibit CNG/311 is a format example with no specific projects or dollar significance intended. Lines 1 – 7 in the exhibit represent individual projects included in the mechanism. The number and cost of the projects will vary from year to year. Column (b) shows the estimated cost to be recovered with column (c) identifying actual costs spent from September 1 through June 30. In the September 15 update filing, both column (b) and (c) will be the same and represent actual costs for the twelve months ended August 31.

Line 8 is the total of all projects. Line 9 comes from the accepted rate base allocation from the current cost of service study in this filing. The rate base allocator will be used to allocate the plant additions to each customer class. Line 10 shows the percentage split based on the previous line.

Line 11 is a reiteration of line 8, total replacement costs. Lines 12 – 23 calculate the revenue requirement impact of the investment. The calculation takes into account the average depreciation rate approved in Cascade's last depreciation study, line 12. The accumulated depreciation impact is derived on line 13, assuming a half year convention. Line 14 calculates tax depreciation in order to determine the deferred tax component on line 16. Line 17 is the tax effect of depreciation expense.

Line 18 is the calculated rate base. Line 19 is the rate of return authorized in this current filing. Line 20 shows the Net Income impact of the rate base and income statement with line 21 showing the total. Line 22 is the conversion factor derived in this current rate case filing. Line 23 is the total revenue requirement associated with the first year of the pipeline replacement investment.

Line 24 shows the allocation of the revenue requirement to each of the rate schedules based on the rate base allocation percentage shown on line 10. Line 25 shows the weather normalized volumes expected in the upcoming year. This volume projection will be the same as used in the concurrent PGA filing.

Line 26 will show the proposed rate impact to be included on a newly established tariff schedule.

Q. How will the exhibit look in subsequent year's filing?

A. Each subsequent year will add an additional sheet similar to this exhibit in order to reflect an additional year of depreciation and deferred taxes on the rate base. In subsequent years the first page will look the same as this exhibit with the exception of addition lines will be added to bring forward the previous year's new rate base level. There will be a second page which will look identical to first year with the exception of added accumulated depreciation and added deferred taxes.

Q. Does Cascade currently have a similar mechanism in place in Washington?

A. Yes. As a result of a generic proceeding (docket UG-120715), the WUTC issued a policy statement with the intent of encouraging natural gas utilities to be proactive in replacing higher risk pipelines. The policy encourages the utilities to submit a replacement plan which is to be updated every two years. The utilities then have the option to file a recovery mechanism for the investment associated with the plan. The plan uses the DIMP as its primary support.

Q. Will Cascade also file a plan as part of its proposal in this docket?

A. Yes. Cascade intends to use its planning document filed in Washington to cover Oregon investments and file every two years as well.

Q. Is Cascade proposing any differences than what has been adopted in Washington?

A. Yes. The recommended changes are for timing and simplicity. In Washington, Cascade files the CRM first in May with two updates on September 30 and again in the middle of October. The last filing includes actual investment through September 30 with estimated investment through October 30. The idea is that all investment will be in service as of the November 1 effective date of the new rates. In Oregon, Cascade is proposing to file only one update as opposed to two and only include actual investment made with no estimates in the final request. The original filing will be on August 1 instead of the May date used in Washington.

Q. Has the Commission approved this type of mechanism before?

A. Yes. Northwest Natural Gas currently has System Integrity Program, which was adopted to encourage Northwest Natural to replace bare steel and cast iron pipe.[8] Cascade's Washington cost recovery mechanism was based one Northwest Natural mechanism in place in Oregon. Cascade's proposal is a simplified, straight forward version of the mechanism currently in place with Northwest Natural.

VII. BASIC CHARGE RECOMMENDATION

Q. Please explain why Cascade is proposing to hold basic charges constant?

A. Cascade believes in promoting the direct use of natural gas for heating homes and water. We realize that customers who choose to use natural gas will also be electricity customers, and for that reason, will have two energy bills to pay each

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[8] *In the Matter of Northwest Natural Gas Company, dba NW Natural*, Docket UM 1406, Order No. 09-067 (Mar. 1, 2009).

month regardless of usage. Cascade is proposing to continue with a low basic charge and volumetric heavy rate design to alleviate that impact on customers.

Q. Why is it appropriate for the Company's rate structure to support the direct use of natural gas?

A. There are two primary reasons; first, direct use of natural gas is much more efficient than using natural gas to produce electricity. Secondly, decreasing usage is the most efficient form of conservation an electric utility could invest in.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 301

Results of Operation Summary Sheet

Cascade Natural Gas
Results of Operation Summary Sheet
Twelve Months Ended December 31, 2014

	SUMMARY SHEET	2014 Results Per Company Filing (1)	Summary of Adjustments (2)	Test Year Adjusted Total (3)	Requested Reveune Increase (4)	Adjusted Reults After Proposed Revenues (5)
	Operating Revenues					
1	Natural Gas Sales	65,785,175	422,139	66,207,314	3,622,770	69,830,084
2	Gas Transportation Revenue	4,029,534	0	4,029,534		4,029,534
3	Other Operating Revenues	277,779	385,502	663,281		663,281
4	SUBTOTAL	70,092,488	807,641	70,900,129	3,622,770	74,522,899
5	LESS: Nat. Gas/Production Costs	39,527,958	0	39,527,958		39,527,958
6	Revenue Taxes	2,905,229	16,839	2,922,069	75,535	2,997,603
7	**OPERATING MARGIN**	27,659,301	790,802	28,450,103	3,547,235	31,997,338
	Operating Expenses					
8	Production	100,207	2,104	102,311		102,311
9	Distribution	5,413,835	1,458,406	6,872,241		6,872,241
10	Customer Accounts	1,516,549	669,306	2,185,855	27,937	2,213,792
11	Customer Service	250,477	(250,477)	0		0
12	Sales	505	(505)	0		0
13	Administrative and General	5,700,762	(297,563)	5,403,199		5,403,199
14	Depreciation & Amortization	4,880,058	1,042,125	5,922,183		5,922,183
15	Regulatory Debits		0	0		0
16	Taxes Other Than Income	1,870,615	300,604	2,171,219		2,171,219
17	State & Federal Income Taxes	2,399,137	(885,808)	1,513,329	1,405,608	2,918,937
18	**Total Operating Expenses**	22,132,145	2,038,193	24,170,338	1,433,545	25,603,882
19	**Net Operating Revenues**	5,527,156	(1,247,391)	4,279,765	2,113,691	6,393,456
	Rate Base					
20	Total Plant in Service	180,947,303	12,043,418	192,990,721		192,990,721
21	Total Accumulated Depreciation	(85,852,430)	(284,355)	(86,136,785)		(86,136,785)
22	Contributions in Aid of Construction	0	0	0		0
23	Customer Adv. For Construction	(537,712)	0	(537,712)		(537,712)
24	Deferred Accumulated Income Taxes	(25,739,617)	(13,364)	(25,752,981)		(25,752,981)
25	Deferred Debits		0	0		0
26	Working Capital Allowance	2,198,523	2,873,126	5,071,649		5,071,649
27	**TOTAL RATE BASE**	71,016,067	14,618,825	85,634,892	0	85,634,892
28	**Rate of Return**	7.78%		5.00%		7.47%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 302

Revenue Requirement Calculation

Cascade Natural Gas
Revenue Requirement Calculation

1	Adjusted Rate Base	$85,634,892
2	Rate of Return	7.47%
3	Required Return (ln 1 x ln 2)	$6,393,501
4	Adjusted Net Income	$4,279,765
5	Required Net Income Increase (ln 3 - ln 4)	$2,113,736
6	Conversion Factor	0.58346
7	Revenue Increase Required (ln 5 / ln 6)	**$3,622,770**
8	Test Year Adjusted Revenue	$70,900,129
9	Overal Revenue Increase	**5.1097%**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 303

Conversion Factor Calculation

Cascade Natural Gas Conversion Factor Calculation Twelve Months Ended December 31, 2014	
REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00771
Taxes Other - Franchise	0.01835
OPUC Fees	0.00250
Interest expense	
State Taxable Income	0.97144
State Income Tax	0.07381
Federal Taxable Income	0.89763
Federal Income Tax @ 35%	0.31417
Total Income Taxes	0.38798
Total Revenue Sensitive Costs	0.41654
Net-to-Gross Factor	**0.58346**
Combo-State & Federal Income Tax	
State	0.07600
Federal	0.35000
State and Federal Effective Tax Rate	0.3994

CNG/304
Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 304

Proposed Adjustments to Base Year Results

Cascade Natural Gas
Proposed Adjustments to Base Year Results

		Uncollectibles Expense (a)	Removal 25% Membership Fees (b)	Officer Incentive Comp. Adj (c)	Promotional Advertising Adjustment (d)	Interest Coordination Adjustment (e)	PGA Commodity Sharing Adj. (f)	Annualizing Wage Rate Adjustment (g)	Removal of Retiree Medical Credits (h)	2015 Revenue Adjustment (i)	2015 Wage Adjustments (j)	Pension Asset Adjustment (k)
1	**Operating Revenues**											
2	Natural Gas Sales									$422,139		
3	Gas Transportation Revenue											
4	Other Operating Revenues						385,502					
5	SUBTOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$385,502**	**$0**	**$0**	**$422,139**	**$0**	**$0**
6	LESS: Nat. Gas/Production Costs											
7	Revenue Taxes						8,038			8,802		
8	**OPERATING MARGIN**	**$0**	**$0**	**$0**	**$0**	**$0**	**$377,464**	**$0**	**$0**	**$413,337**	**$0**	**$0**
9												
10	**Operating Expenses**											
11	Production											
12	Distribution											
13	Customer Accounts	$278,894					$2,973			$3,255		
14	Customer Service											
15	Sales				(505)							
16	Administrative and General		(3,648)	(135,107)				25,051	(28,075)		175,389	
17	Depreciation & Amortization											
18	Regulatory Debits											
19	Taxes Other Than Income											
20	State & Federal Income Taxes	(111,390)	1,457	53,962	202	(33,808)	149,572	(10,005)	11,213	163,787	(70,050)	0
21	**Total Operating Expenses**	167,504	(2,191)	(81,145)	(303)	(33,808)	152,545	15,046	(16,862)	167,042	105,339	0
22	**Net Operating Revenues**	($167,504)	$2,191	$81,145	$303	$33,808	$224,920	($15,046)	$16,862	$246,295	($105,339)	$0
24	**Rate Base**											
25	Total Plant in Service											
26	Total Accumulated Depreciation											
27	Contributions in Aid of Construction											
28	Customer Adv. For Construction											
29	Deferred Accumulated Income Taxes											
30	Deferred Debits											
31	Working Capital Allowance											2,873,126
32	**TOTAL RATE BASE**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,873,126
33												
34	**Revenue Requirement Effect**	**$287,087**	**($3,755)**	**($139,076)**	**($520)**	**($57,944)**	**($385,494)**	**$25,787**	**($28,900)**	**($422,130)**	**$180,542**	**$367,648**

Cascade Natural Gas
Proposed Adjustments to Base Year Results

Pipeline Inspection Cost Adj (l)	Labor Additions Adjustment (m)	Public Purpose Cost Reallocation (n)	2015 Plant Additions (o)	Reallocation of A&G Charges (p)	Rate Case Costs (q)	Inflation Factor Adj (r)	Depreciation Expense Adj (s)	Employee Incentive Plan Adj (t)	Environmental Remediation Adj (u)	**Total Adjustments (Base Rates) (v)**
					$0	$0	$0	$0	$0	422,139
					0	0	0	0	0	0
					0	0	0	0	0	385,502
$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$807,641**
										$0
										$16,839
$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	$790,802
										$0
										$0
						2,104				$2,104
342,238	590,631					56,900			468,637	$1,458,406
				$352,337		31,848				$669,306
		(250,477)				0				($250,477)
										($505)
				(474,566)	186,275	69,222		(112,104)		($297,563)
			568,710				473,415			$1,042,125
										$0
			178,375	122,229						$300,604
(136,690)	(235,898)	100,041	(298,386)	0	(74,398)	(63,933)	(189,082)	44,774	(187,174)	($885,808)
205,548	354,733	(150,436)	448,699	0	111,877	96,140	284,333	(67,330)	281,463	$2,038,193
($205,548)	($354,733)	$150,436	($448,699)	$0	($111,877)	($96,140)	($284,333)	$67,330	($281,463)	($1,247,391)
			12,043,418							$12,043,418
			(284,355)							($284,355)
										$0
										$0
			(13,364)							($13,364)
										$0
										$2,873,126
$0	$0	$0	$11,745,699	$0	$0	$0	$0	$0	$0	$14,618,825
$352,293	**$607,983**	**($257,836)**	**$2,272,027**	**$0**	**$191,748**	**$164,777**	**$487,323**	**($115,398)**	**$482,405**	**$4,008,567**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 305

Independent Evaluator's Report (without appendices)

CASCADE NATURAL GAS® CORPORATION
A Subsidiary of MDU Resources Group, Inc.

222 FAIRVIEW AVENUE N., SEATTLE WASHINGTON 98109-5312 206-624-3900
FACSIMILE 206-654-4039
www.cngc.com

April 30, 2010

Oregon Public Utility Commission
Attn: Vikie Bailey-Goggins
550 Capitol Street NE #215
Salem, OR 97308-2148

Re: UG 167 – Third Party Evaluation of Cascade Natural Gas Corporation's Oregon Decoupling Mechanism

Dear Ms. Bailey-Goggins:

In compliance with Item 8, Order 06-191 in the UG 167 Stipulation agreement, Cascade Natural Gas Corporation herein submits the attached report related to the Independent Third-Party Evaluation of Cascade Natural Gas Corporation's Oregon Decoupling Mechanism.

On March 19, 2010, Cascade submitted a request for a six-week extension to the March 31, 2010, filing deadline of the report to allow adequate time for the independent consultant to finalize the report. An extension was subsequently granted to May 15, 2010, in a ruling made by Judge Allan J. Arlow on March 22, 2010.

If you have any questions concerning this submittal, please contact Allison Spector at 206-381-6834 or Katherine Barnard at 206-381-6824.

Sincerely,

Katherine J Barnard

Katherine J. Barnard
Manager
Regulatory & Gas Supply

BUILDING A WORLD OF DIFFERENCE®

BLACK & VEATCH

Cascade Natural Gas Corporation

Independent Third-Party Evaluation of Oregon Decoupling Mechanism

Final Report

April 2010

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1.0 EXECUTIVE SUMMARY

The purpose of this report is to present the results of Black & Veatch Corporation's (Black & Veatch) evaluation and investigation of Cascade Natural Gas Corporation's (Cascade, CNGC, or the Company) natural gas revenue decoupling mechanism in Oregon, which is part of the Company's Conservation Alliance Plan (CAP). The primary objective of this evaluation was to determine the effectiveness of the CAP, which became effective on May 1, 2006. Specifically, Black & Veatch evaluated whether the implementation of the decoupling mechanism has been achieved as planned, and whether the mechanism has had a positive impact on the Company's commitment to natural gas conservation programs.

Black & Veatch recognizes that there should be a close interrelationship between the Company's decoupling mechanism and the advancement of cost-effective, economically-efficient conservation programs, and that determining whether this interrelationship exists is the key question to be answered by this evaluation. A properly designed revenue decoupling mechanism should better align the interests of the Company with those of its customers and the energy policies of the State. The mechanism should mitigate CNGC's disincentive to promote energy efficiency (i.e., eliminate its "throughput incentive"), thereby providing its customers with increased opportunities to reduce energy consumption and energy bills as a result of the various energy efficiency and conservation programs supported by the Company.

To determine whether the interrelationship exists between the Company's decoupling mechanism and the advancement of cost-effective economically-efficient conservation programs, Black & Veatch conducted an independent investigation of the decoupling mechanism that included addressing a number of substantive questions, as discussed throughout this report.

On April 19, 2006, the Public Utility Commission of Oregon (Commission) issued a final Order in Docket UG 167 approving a Stipulation granting Cascade's request for approval of its CAP, which included a natural gas revenue decoupling mechanism, subject to certain conditions. Under the terms of the Stipulation, Cascade was authorized to implement the CAP mechanism in order to separately track variations in natural gas usage due to conservation and weather. The two resulting deferral accounts track the margin impact of changes in the normalized use per customer for the Company's Residential Service Rate Schedule 101 and its Commercial Service Rate Schedule 104, as well as the impact of weather changes from normal weather for these same rate schedules.

Under the terms of the Stipulation, the Parties agreed that Cascade would sponsor a study, performed by an independent firm, for the purpose of evaluating the effectiveness of the CAP—whose results would be submitted to the Parties listed in the Order as well as to the Commission. This report presents the results of this required evaluation.

The purpose of Cascade's CAP mechanism is to establish procedures for the annual tracking of commodity margin revenue differences occurring from both weather and conservation. Rates are revised annually to reflect changes in both the weather-normalized use per customer and the difference between actual use and weather-normalized use per customer, and the baseline normalized use established in the Company's most recent rate case. The sum of these two rate adjustment components permits the Company to calculate the margin revenue differences experienced between the actual average residential and commercial/industrial (C/I) margin per customer and the margin amounts established at the time the Company's rates were authorized by the Commission. The resulting revenue difference, whether positive or negative, is added to the existing commodity margin for the next annual period by dividing the expected annual commodity margin by the normalized therm sales.

The objectives of this evaluation were established by the Company and other Parties, and they were included in CNGC's Request-for-Proposals (RFP). The specific program elements that were evaluated by Black & Veatch were included in the Evaluation Plan (provided as Appendix B of the RFP) and they were broken down into the following categories:

1. Mechanism Structure and Design
2. Customer Impacts
3. Company Impacts
4. Associated Conservation Efforts and Achievements
5. Societal Impact and Benefits

This Evaluation Plan is provided in Appendix A of this report, along with references to the sections of this report that address each of the questions contained in the Plan.

1.1 Conclusions

Black & Veatch's conclusions resulting from this evaluation are summarized below. These conclusions and the supporting analysis are discussed in more detail in *Section 3, Observations Regarding Structure of Decoupling Mechanism*, and *Section 4, Observations Regarding Impact of Decoupling Mechanism on Conservation Activities*.

1.1.1 Decoupling Mechanism Structure

From a purely computational standpoint, the Company's decoupling mechanism works as designed. The mechanism uses a multi-step process to adjust calendar month data. First, weather normalized sales are calculated for each of the Company's three weather areas by multiplying the monthly number of customers times the difference between normal and actual heating degree days (HDD) times the weather sensitive coefficient for the area. Second, the expected monthly normalized commodity revenue per customer (as determined in the Company's most recent rate case) is calculated. This calculation multiplies the total number of residential customers times the monthly commodity margin. The actual commodity margin is determined as the actual commodity sales (net of the current month unbilled calculation) times the applicable commodity charge. The weather adjustment margin is added to or subtracted from the actual revenue to produce a weather normalized margin. The difference between the weather normalized margin and the expected normalized margin is the conservation adjustment.

The Company's filings that Black & Veatch reviewed have accurately implemented the resulting rate adjustments through CNGC's decoupling mechanism, and the Company stated that it is satisfied with the simplicity and recovery basis of the mechanism. The resulting decoupling adjustments have been minor and Black & Veatch does not believe there is a need to extend the amortization period to lessen the impact on customers, nor should the monthly timing of the rate adjustments be changed. Further, Black & Veatch does not believe that the Company's decoupling mechanism should be extended to CNGC's other rate classes. Black & Veatch also believes that the Company's decoupling mechanism has not led to unfair penalties for customers not participating in conservation programs. Finally, Black & Veatch found no evidence that the Company's decoupling mechanism has created any unanticipated disincentives.

Company representatives stated that they believe the mechanism has removed its disincentive to promote conservation, noting that the Company receives a net margin per customer, thereby accommodating the impacts of conservation and weather. They further stated that the decoupling mechanism has allowed the Company to increase its promotion of conservation, which has resulted in positive environmental impacts.

The Company also noted that the public purpose surcharge is the funding vehicle for conservation, while the decoupling mechanism removes the financial disincentives associated with implementing conservation programs. In that regard, these two ratemaking elements are completely linked from the perspective of the Company, particularly given the fact that local distribution companies (LDCs) in Oregon are not required to have a public purpose fund. The Company also noted that with regard to the public purpose fund rate of 1.5 percent of revenues; 0.75 percent is funded by ratepayers, and 0.75 percent is funded by shareholders—with the later contribution viewed as the "give back" for the Company being granted margin certainty (not earnings certainty). Based upon the results of this evaluation, Black & Veatch agrees with this conclusion.

It should also be noted that the decoupling adjustments impact only one side of the Company's earnings equation, namely utility rate revenues produced through volumetric rates. The decoupling adjustments do not impact the cost or expense risk associated with the Company's earnings. In general, there is broad recognition in the gas utility industry of the role of full and partial decoupling mechanisms for LDCs. As a result, many of Cascade's peer companies have in place ratemaking provisions (e.g., revenue decoupling; Straight Fixed-Variable or SFV rates; and weather normalization adjustment mechanisms) designed to provide an enhanced opportunity to collect revenues consistent with the level of revenues approved by regulators in their last rate cases. To the extent the authorized equity return for the Company is based on a determination which relies upon financial data of other companies, the effect of revenue recovery from decoupling on the Company's risks is already largely accounted for in the returns of the other companies. Therefore, Black & Veatch believes that any adjustment to the Company's authorized rate of return associated with implementation of Cascade's decoupling mechanism is unnecessary and inappropriate. In the larger context, Black & Veatch understands that the Company contributes 0.75 percent of revenues (or about $630,000 in 2008, before taxes) to help fund conservation programs as part of the CAP Stipulation. This effectively reduces the earned return for CNGC by the amount of the contribution, and effectively reduces the authorized return prior to the effect of any decoupling adjustment on Company revenues. It is important to recognize that this sizable contribution effectively means that regardless of the level of return on equity authorized by the Commission, the Company has a diminished opportunity to earn its authorized rate of return. Also, the existence of the earnings sharing mechanism provides an upside cap on the ability of the Company to over earn. In Black & Veatch's view, there is no justification for further reducing the Company's authorized return on equity based on the operation of its decoupling mechanism.

One stakeholder noted that his primary concern is to make sure that the Company's decoupling mechanism is being applied correctly, that only true fixed costs are included, and that the calculation of lost margins is actually based on margins lost "at the margin". Black & Veatch concludes that these concerns have been fully addressed in the Company's decoupling mechanism.

Finally, one stakeholder stated that the evaluation of any decoupling mechanism needs to consider the broader regulatory context within which the mechanism operates. As an example, this stakeholder noted that the Company has an earnings sharing mechanism in place in Oregon. This mechanism has been in place for a number of years and has been modified within the last 18 months. According to this stakeholder, the mechanism has been strengthened from a customer perspective to include tighter bands within which earnings are shared. As a result of this change, the chance of significant over-recovery of costs by the Company due to the decoupling mechanism has been lessened. This stakeholder also noted that the Show Cause Rate Case and the MDU Resources (MDU) Acquisition Case led to lower authorized returns on equity for the Company. As a result, this stakeholder believes that the overall impact of the decoupling mechanism is balanced for both the Company and its customers when CNGC's entire regulatory picture is considered. Black & Veatch concurs with this conclusion.

As part of our review, Black & Veatch reviewed all regulatory filings related to the Company's decoupling mechanism. Based on our review, Black & Veatch concludes that the Company's decoupling mechanism has been implemented properly and that the resulting rate adjustments have been consistent with the associated tariff provisions. We believe that our review of these filings and their subsequent amendments, indicate that the public interest is protected through the current CAP process. Therefore, Black & Veatch believes that the Company's decoupling mechanism is fundamentally sound and the elimination of the mechanism would be harmful to the Company, its customers, and the environment. However, Black & Veatch believes that certain issues pertaining to the ongoing operation of the mechanism should be addressed, as discussed in this report.

1.1.2 Conservation Programs

Participation in conservation programs by Cascade's residential customers steadily increased during the evaluation period. The C/I data do not show as clear a pattern, as no programs were available to this sector prior to decoupling, and the data do not show an increasing trend. In total, conservation activity has increased, coincident with the advent of decoupling in the Company's service area. Consistent with the increase in Cascade customer participation in conservation programs, the Company's conservation-related expenditures have increased during the evaluation period. As conservation results in lower energy usage, the increased savings resulting from the Company's conservation programs have a direct positive impact on the environment.

Total therm savings has increased significantly during the evaluation period, although savings per participant levels have decreased and total savings have fallen short of the targets established in the Company's 2008 Integrated Resource Plan (IRP) although the total savings in 2009 were approximately 88 percent higher than in 2008. The short-fall in 2009 is most likely the result of the economic downturn resulting in customers not having the available funds to spend on discretionary measures. Other factors, such as code changes and the impact of the recession on new construction may also be responsible for lower customer participation. Furthermore, the amount of therms saved per participant among the low income sector dropped in half between 2006 and 2007, and has remained at that level ever since. It should be noted that the Company began using the deemed savings approach to estimating savings in 2006, similar to the methodology used in Northwest Natural Gas Company's (NWNG) conservation programs, whereas prior estimates were taken from REM/Rate audit results. This change in estimating methodology may have also impacted the level of reported savings.

Black & Veatch also examined whether decoupling has led to higher levels of spending by the Company on marketing and outreach to customers, more messages and educational materials for customers related to the benefits of conservation, and processes put into place to facilitate customers' participation in programs. This outcome is documented in the body of this report as having indeed occurred. However, in spite of the high degree of collaboration between the Company and the ETO on print and other media, a few concerns were expressed by the Company about the effectiveness of the ETO's outreach efforts.

Prior to the implementation of the decoupling mechanism, the Company did not have a conservation-dedicated staff position. Since then, the Company created a Conservation Department in 2006. Today, there are three staff members in the Company's Conservation Department including its Director. Furthermore, decoupling clearly has had a direct and positive effect on Cascade's embracing of conservation as evidenced by the involvement and messages of employees from senior management as well as Company staff.

During Black & Veatch's interviews with Company and stakeholder representatives, we received both positive and negative comments regarding the ETO's conservation efforts. First, the positive comments focused on the ETO's experience and cost-effectiveness in delivering its programs, and the fact that they have existing programs in place that could be quickly transferred to Cascade. The negative comments relate primarily to limitations in the ETO's outreach efforts within the Company's service territory to date, its governance structure and responsiveness to gas company needs.

Cascade's 2008 IRP refers to a conservation potential analysis that indicates that over the IRP's 20-year planning horizon the technical potential associated with cost-effective conservation measures to be approximately 24 million therms in Oregon. As a result, significant additional conservation potential exists in the Company's Oregon service territory.

According to reports provided by Cascade, residential customer satisfaction levels decreased from 4.5 in 2006 to 4.4 in 2007. Overall customer service ratings increased and then remained the same between 2008 and 2009. Black & Veatch's customer surveys asked about customers' perceptions regarding the quality of service received from Cascade post decoupling indicate that the majority of customers believe that quality of service has remained the same, but 15 percent of the Company's residential customers and 17 percent of its C/I customers believe it has improved either slightly or significantly. There was no statistically significant difference in the reported level of customer satisfaction between participants and non-participants.

1.2 Recommendations

Black & Veatch's recommendations resulting from this evaluation are summarized below. These recommendations are discussed in more detail in *Section 4, Recommendations*.

1.2.1 Decoupling Mechanism Structure

1. The Company's decoupling mechanism should be made permanent. Furthermore, the decoupling rate adjustments should continue to apply only to the Company's residential and general service rates. At the same time, some potential modifications to the Company's decoupling mechanism, as described below, should be considered for implementation in the Company's next rate case filing.
2. Review and update the use per HDD factors utilized in the Company's weather normalization equation and factors in its next rate case.
3. Eliminate the use of unbilled volumes in the monthly decoupling adjustment calculations since there is no demonstrated need to have such an adjustment reflected in CNGC's decoupling mechanism.
4. Analyze the Company's Rate 104 class to determine if splitting the class based on meter size and type (or other reasonable basis) would result in two or more sub-groups that exhibit more homogeneous load and cost characteristics.
5. The deferral and recovery aspect of the Company's CAP adjustments should, at a minimum, consider the real-time recovery of the weather adjustment component. Under real-time recovery, the weather component of the CAP adjustment would be added to each cycle bill.
6. Consider other decoupling methods that reduce the impact on customers below the poverty level and target these customers for conservation programs designed to reduce average use per customer.
7. Consider the possible adoption of SFV rates as an alternative ratemaking method to achieve revenue decoupling for the Company. This ratemaking approach has been adopted in some states and is simple, cost-based, economically-efficient, and does not create any intra-class subsidies.

1.2.2 Conservation Programs

1. Although participation levels are high and increasing, the extent of awareness of the role of Cascade in the promotion of conservation remains low among residential customers.
2. Further, the next ETO Oregon Residential Awareness and Perception Study should sample by utility rather than at the regional level, so that accurate findings by utility sponsor can be obtained. The data should also then be reported by utility sponsor so that the ETO and the sponsors can determine whether their customers are being adequately served. Although ETO staff question the cost-effectiveness of increasing the number of awareness survey participants in Cascade's service territory, and has raised issues regarding the value of using awareness surveys as an indicator of participation or satisfaction with participation, Black & Veatch believes that such surveys remain a widely accepted evaluation tool and that a larger sample size would provide data for the Company's service territory at the same level of precision as other sponsoring utilities.
3. The ETO's mailing of energy kits to the Company's customers drove the residential average therm savings per participant numbers down in 2009. Black & Veatch believes that the ETO should refocus its efforts on delivering programs that generate higher savings impacts per participant.
4. The ETO's recommendation that its furnace replacement program be refocused because portions of the market have been saturated is not relevant to Cascade, which has significant additional furnace-related conservation potential within its service area. Black & Veatch believes that the ETO's furnace rebate program should continue to be offered to all Cascade's residential customers.
5. Behavior-based programs are a new trend in the conservation community. While there are several promising new tools (e.g., on-line audits, bill disaggregation, etc.), this next generation of programs may be more relevant for highly energy efficient market segments such as other areas that are being served by the ETO (i.e., the Portland area). It would be of considerable concern if behavior-based programs were to replace or even dominate the portfolio in Cascade's service territory given the remaining opportunities for equipment-based and comprehensive weatherization programs.

2.0 INTRODUCTION

This report summarizes the results of Black & Veatch's investigation of Cascade's natural gas revenue decoupling mechanism in Oregon, which is part of the Company's CAP. The primary objective of this evaluation was to determine the effectiveness of the CAP, which became effective on May 1, 2006. Specifically, Black & Veatch evaluated whether the implementation of the decoupling mechanism has been achieved as planned, and whether the mechanism has had a positive impact on the Company's commitment to natural gas conservation programs. The time period for this evaluation is 2004 through 2009.

Black & Veatch recognizes that there should be a close interrelationship between the Company's decoupling mechanism and the advancement of cost-effective, economically-efficient conservation programs, and that determining whether this interrelationship exists is the key question to be answered by this evaluation. A properly designed revenue decoupling mechanism should better align the interests of the Company with those of its customers and the energy policies of the State. The mechanism should mitigate CNGC's disincentive to promote energy efficiency (i.e., eliminate its "throughput incentive"), thereby providing its customers with increased opportunities to reduce energy consumption and energy bills as a result of the various energy efficiency and conservation programs supported by the Company.

To determine whether the interrelationship exists between the Company's decoupling mechanism and the advancement of cost-effective economically-efficient conservation programs, Black & Veatch conducted an independent investigation of the decoupling mechanism that included addressing a number of substantive questions, as discussed throughout this report.

2.1 Background and Structure of Decoupling Mechanism

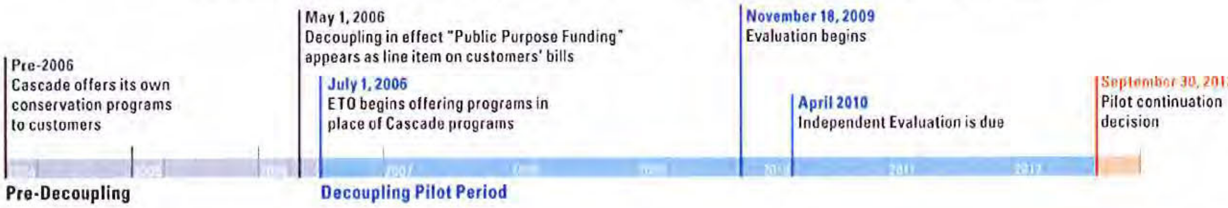
On April 19, 2006, the Commission issued a final Order in Docket UG 167 approving a Stipulation granting Cascade's request for approval of its CAP, which included a natural gas revenue decoupling mechanism, subject to certain conditions. Under the terms of the Stipulation, Cascade was authorized to implement the CAP mechanism in order to separately track variations in natural gas usage due to conservation and weather. The Parties further agreed that Cascade would sponsor a study, performed by an independent firm, for the purpose of evaluating the effectiveness of the CAP—whose results would be submitted to the Parties listed in the Order as well as to the Commission.

The purpose of Cascade's CAP mechanism is to establish procedures for the annual tracking of commodity margin revenue differences occurring from both weather and conservation. Rates are revised annually to reflect changes in both the weather-normalized use per customer and the difference between actual use and weather-normalized use per customer, and the baseline normalized use established in the Company's most recent rate case. The sum of these two rate adjustment components permits the Company to calculate the margin revenue differences experienced between the actual average residential and C/I margin per customer and the margin amounts estimated at the time the Company's rates were authorized by the Commission. The resulting revenue difference, whether positive or negative, is added to the existing commodity margin for the next annual period by dividing the expected annual commodity margin by the normalized therm sales.

Cascade maintains separate Conservation Variance and Weather Variance deferral accounts (i.e., the Decoupling Mechanism) as regulatory assets or liabilities. Each month, Cascade calculates the difference between the weather-normalized actual margin and the expected margin for each applicable rate schedule. The expected margin is calculated as the baseline average commodity per customer multiplied by the current customer count. The resulting dollar amount difference is recorded in the Conservation Variance deferral account. Cascade also calculates the difference between non-weather normalized actual margin and the expected margin for its applicable rate schedules, and the resulting difference is reduced by subtracting the dollar amount recorded in the Conservation Variance deferral account with the remainder recorded in the Weather Variance deferral account. Temporary surcharges or refund amounts are applied to the Margin Commodity Rate over the following annual amortization period—with the potential for a different amortization period if the rate changes are considered excessive.

Figure 2-1 presents a timeline of key milestones related to the Company's decoupling mechanism and this evaluation. For purposes of this evaluation, the pre-decoupling period is characterized as the period prior to May 2006, when the decoupling mechanism took effect. The decoupling mechanism's pilot period is assumed to be represented by activities after May 2006 through September 2010, at which time the Commission will determine whether the Company's decoupling mechanism should be continued.

Figure 2-1
Cascade's Revenue Decoupling Mechanism—Timeline of Key Milestones



2.2 Conservation Programs

Prior to the implementation of its decoupling mechanism, Cascade offered a limited selection of conservation programs to its residential customers. Cascade began its partnership with the Oregon Low Income Weatherization Assistance Program in 1979 and has had weatherization programs for all customers since at least 1981. In May 2006, a "public purpose surcharge" took effect on Cascade customers' bills to help fund conservation programs that would subsequently be implemented by the ETO. Cascade and its shareholders provide additional funds to the ETO to deliver programs to Cascade's customers on the Company's behalf. The ETO took over conservation program implementation on July 1, 2006, as a result of a transition initiated by the Company following the Commission's authorization of the decoupling mechanism and the public purpose surcharge.

The left-hand column of Table 2-1 lists the conservation programs offered by Cascade prior to implementation of decoupling, together with the applicable customer segment and the date each program started. The right-hand column presents a list of comparable programs subsequently offered to Cascade's customers by the ETO after July 1, 2006.

It is recognized by Black & Veatch that this is an evaluation of the decoupling mechanism and not of the ETO. However, the simultaneous introduction of the decoupling mechanism and the ETO's program offerings required Black & Veatch to isolate the effects of each, to the extent possible, in order to identify the effects of the decoupling mechanism alone.

Finally, it is important to note in reviewing these conclusions that Cascade's customers were not provided any direct communications by the Company concerning the decoupling mechanism per se, and would thus not be expected to have awareness of "decoupling" as a mechanism or a term. Rather, according to interviews with Company staff, the communications provided were indirectly related to decoupling, and concerned: 1) the implementation of the public purpose surcharge on their gas bill, and 2) communications about the energy conservation programs offered by the ETO as of July 1, 2006. Since it is unlikely that customers would be able to respond to questions about "decoupling," this evaluation sought to measure awareness and responses to the indirect factors of the public purpose surcharge and the heightened marketing and outreach associated with ETO's programs.

Table 2-1
Conservation Programs Available to Cascade's Customers

Cascade Programs (Pre-2006)	ETO Programs (2006 to Present)
• Residential - Weatherization Program – low income since 1979; insulation for all residential customers since 1981 • Residential - High-Efficiency Furnace - Heating and Cooling Rebate Program - 2004 • Residential - High-Efficiency Water Heaters - Heating and Cooling Rebate Program - 2004 • Residential - Low Income Weatherization Program - 2004	• Residential – High-Efficiency Furnace - Heating and Cooling Rebate Program - 2006 • Residential - High-Efficiency Water Heaters - Heating and Cooling Rebate Program - 2006 • Residential - Low Income Weatherization Program - 2006 • Residential - New Homes and Products - Audit Program - 2005 • Residential - Existing Homes - Audit Program - 2006 • Residential - Energy Savings Kits - General Improvement Program - 2006 • C/I - Existing Buildings - Audit Program - 2006 • C/I - New Buildings - Audit Program - 2007 • C/I - Production Efficiency - Audit Program - 2009

2.3 Assessment Objectives and Areas of Inquiry

The objectives of this evaluation were established by the Company and other Parties, and they were included in CNGC's RFP. The specific program elements that were evaluated by Black & Veatch were included in the Evaluation Plan (provided as Appendix B of the RFP) and they were broken down into the following categories:

1. Mechanism Structure and Design
2. Customer Impacts
3. Company Impacts
4. Associated Conservation Efforts and Achievements
5. Societal Impact and Benefits

This Evaluation Plan is provided in Appendix A of this report, along with references to the sections of this report that address each of the questions contained in the Plan.

In addition to the questions contained in the Evaluation Plan, Black & Veatch used the following generic evaluation criteria to conduct its specific review of the Company's decoupling mechanism:

- Ability to meet desired design objectives:
  - Enhances utility's fixed cost recovery
  - Removes utility's disincentive to promote energy efficiency
  - Other customer-related benefits
- Any limitations on the recovery of margin deficiencies
- Ability to avoid large and abrupt rate adjustments
- Simple to administer
- Others as identified through stakeholder interviews

2.4 Project Approach

Our project approach included the following four tasks.

2.4.1 Project Initiation

Black & Veatch conducted a project initiation meeting with the Company and other Parties to commence the project, review the objectives, and confirm the overall evaluation approach, work plan, and schedule. Black & Veatch also submitted an initial data request to the Company to obtain the necessary background information and supporting data to conduct its evaluation.

2.4.2 Develop Data to Respond to the Evaluation Plan Questions

This task involved significant data collection and analysis related to both qualitative and quantitative assessments of the Company's decoupling mechanism.

2.4.3 Evaluate CNGC's Decoupling Mechanism

In this task, Black & Veatch evaluated the Company's decoupling mechanism according to the questions contained in the Evaluation Plan. These questions were supplemented with others based on Black & Veatch's knowledge of the revenue decoupling mechanisms approved in other states. Black & Veatch used quantitative measures (e.g., total margin revenue, rate adjustment levels, bill impacts, and so forth) to assess the performance of the Company's decoupling mechanism. Black & Veatch also relied upon more qualitative measures (e.g., changes in the business objectives and activities of the Company's marketing staff) to conduct this assessment.

The Black & Veatch project team interviewed a number of individuals from the following Parties to solicit their inputs as part of this task:

- Cascade
- Commission Staff
- Citizens' Utility Board of Oregon
- Northwest Industrial Gas Users
- NW Energy Coalition

Black & Veatch also interviewed several representatives of the ETO and a small sample of Community Action Agencies (CAAs) that serve Cascade's customers.

Black & Veatch reviewed numerous documents that were provided by the Company in response to multiple data requests, as well as material that was provided by the ETO or available on its web site. These documents are listed in Appendix B.

Finally, as part of this task, Black & Veatch conducted telephone surveys of random samples of the Company's residential and commercial customers. Appendices C and D provide the residential and commercial survey instruments, respectively, that were used to conduct these surveys.

2.4.4 Prepare Written Report

To conclude this project, Black & Veatch prepared this report to summarize the observations, conclusions, and recommendations resulting from this evaluation.

SECTION 3 OBSERVATIONS REGARDING STRUCTURE OF DECOUPLING MECHANISM

3.0 OBSERVATIONS REGARDING STRUCTURE OF DECOUPLING MECHANISM

The purpose of this section is to summarize Black & Veatch's observations and conclusions regarding the structure and Company's application of the decoupling mechanism. It begins with a discussion of the structure and design of the decoupling mechanism, followed by a discussion of the impact of the mechanism on customers and the Company.

3.1 Mechanism's Structure and Design

3.1.1 Application of Decoupling Mechanism

A properly designed revenue decoupling mechanism should better align the interests of the Company with those of its customers and the energy policies of Oregon by mitigating the utility's disincentive to promote energy efficiency (i.e., eliminate its "throughput incentive") and, thereby, removing the Company's disincentives for providing customers with increased opportunities to reduce energy consumption and energy bills through the various energy efficiency and conservation initiatives supported by the Company.

As part of the evaluation of the Company's current decoupling mechanism, Black & Veatch began by reviewing the Commission's Order 06-191 approving the Company's CAP of which the decoupling mechanism was an integral part. Under the Order, the Company's decoupling mechanism is comprised of two deferral accounts, which track the margin impact of changes in the normalized use per customer for the Residential Service Rate Schedule 101 and the Commercial Service Rate Schedule 104, as well as the impact of weather changes from normal weather for the same schedules. The mechanism does not apply to other rate schedules. The calculation of the deferral amounts occurs monthly and results in either a regulatory asset or liability associated with the actual consumption occurring in the month. CNGC files annually with the Commission to adjust its base rates (i.e., the Delivery Charge per therm) and its Temporary Adjustment per therm. As part of its annual Purchased Gas Adjustment (PGA) filing, CNGC files detailed schedules for all of its deferral accounts, including those related to the decoupling mechanism. In addition, Black & Veatch reviewed each filing and the subsequent revisions made pursuant to the Commission's Orders.

3.1.2 Weather Normalization and Conservation Adjustments

The mechanics of the decoupling adjustment include calculating both a weather component and a conservation component. The decoupling mechanism uses a multi-step process to adjust calendar month data. First, weather normalized sales are calculated for the three weather areas by multiplying the monthly number of customers times the difference between normal and actual HDD times the weather sensitive coefficient for the area and month. Second, the expected monthly normalized commodity revenue per customer as determined in the most recent rate case is calculated. This calculation multiplies the Company's total residential customers times the monthly commodity margin. Third, the actual commodity margin is determined as the actual commodity sales net of the current month unbilled calculation times the applicable commodity charge. The weather adjustment margin (current commodity charge multiplied by the weather adjustment volume) is added to or subtracted from the actual revenue to produce a weather normalized margin. The difference between the weather normalized margin and the expected normalized margin is the conservation adjustment. The following equations illustrate the monthly calculation.

SECTION 3 OBSERVATIONS REGARDING STRUCTURE OF DECOUPLING MECHANISM

$DA_i = W_i + C_i$ (the basic decoupling formula)

$W_i = CUST_{ij} * (NHDD_{ij} - AHDD_{ij}) * HSF_{ij} * CCC_i$ (the weather adjustment)

and

$C_i = (\sum_{j=1}^{3} CUST_{ij} * ECM_i) - (W_i + (CCC_i * ACS_i))$ (the conservation adjustment)

Where:

DA_i is the ith monthly decoupling adjustment

W_i is the ith monthly weather adjustment stated in dollars

C_i is the ith monthly conservation adjustment stated in dollars

$CUST_{ij}$ is the ith monthly number of customers in the jth customer zone

$NHDD_{ij}$ is the normal heating degree days for the ith month in the jth climate zone

$AHDD_{ij}$ is the actual heating degree days in the ith month in the jth zone

HSF_{ij} is the heat sensitive factor for the ith month in the jth zone

CCC_i is the current commodity charge in the ith month

ECM_i is the expected commodity margin per customer in the ith month

ACS_i is the actual commodity sales net of unbilled adjustment in the ith month

The net result of these equations is that the total of the weather and conservation adjustments plus actual commodity revenues equals the monthly expected commodity margin. Thus the decoupling mechanism adjusts the Company's actual revenue per customer in each month to equal the expected revenue per customer from its last rate determination. This can be seen by rearranging the terms of the conservation equation as follows:

$$\sum_{j=1}^{3} CUST_{ij} * ECM_i = C_i + (W_i + (CCC_i * ACS_i))$$

On an annual basis, the total of the two components of the decoupling mechanism produce results as expected as shown in Table 3-1. Although the sign of the conservation component in 2008 is reversed from the theoretical expectation, the overall result is consistent with the underlying process of adjusting the average base rate revenue to the target revenue for each year.[1]

[1] The total annual adjustment is the difference between the expected normalized revenue from a rate schedule and the actual revenue for the year. This difference is split between conservation and weather by calculating the weather adjustment and subtracting that number from the total adjustment to derive the conservation component. Since the

Table 3-1
Annual Residential Weather and Conservation Adjustments

CAP Adjustment	2006	2007	2008	2009
HDDs	Warmer	Warmer	Colder	Warmer
Weather	$52,322	$174,723	($542,023)	$13,041
Conservation	$47,950	$380,156	($358,680)	$83,051
Total	$100,272	$554,879	($900,703)	$96,092

When viewing the separate components on a monthly and annual basis, the resulting adjustments appear to produce counter-intuitive results. The weather normalization component follows the expected logic of either increasing or decreasing revenues based on the underlying weather conditions. However, the margin impact based on normalized use per customer does not follow the expected pattern of increasing revenue to reflect conservation since average use declines in each year. Instead, the adjustment actually decreases revenue in some months, and in one year, suggesting that conservation has not occurred. Table 3-2 provides an example of these monthly results while Table 3-1 illustrates the one year in which the conservation adjustment produces a counterintuitive result.

Table 3-2
FY 2007 Residential Weather and Conservation Adjustments

CAP Adjustment	Dec. 2006	Jan. 2007	Feb. 2007	Apr. 2007	May 2007
HDDs	Warmer	Colder	Warmer	Colder	Warmer
Weather	$87,965	($117,202)	$22,322	($9,578)	$54,215
Conservation	$379,587	$102,598	($267,960)	$272,013	($79,255)
Total	$467,552	($14,604)	($245,638)	$262,435	$25,040

As the table illustrates, the component for weather follows the weather pattern and the conservation component follows no discernable pattern. Since the Company's sales data represents both billed sales and unbilled volumes, the impact of the unbilled calculation may account for the random changes in the direction of the conservation component. There may also be issues related to the weather normalization process since one would expect over time that the use per HDD would change as a result of factors such as the appliance life cycle/replacement rate, the mix of new homes added to the population, and the effects of other utility-related conservation programs impact on the thermal envelope. This result may occur since under the weather portion of the Company's decoupling mechanism, the use per HDD factor established in each Company rate case does not change between rate cases. Nevertheless, one would not expect to see the conservation adjustment shown in Table 3-2 reflecting an increase in sales regardless of weather. Other reasons for the unexpected results could be a change in the mix of residential customers by climate zone since the calculation for the conservation adjustment is made at the aggregate level, as opposed to the three weather areas being

conservation component is derived as a residual amount under the weather component estimation process, the resulting sign may be reversed from the expected positive sign during periods where conservation occurred.

used to calculate weather normalization. It is reasonable to assume that higher HDDs are consistent with higher margin contribution—all else being equal. The implication of these findings relates to whether or not the Company's decoupling mechanism as calculated actually matches fixed cost recovery within quarterly financial reporting periods. On an annual basis the decoupling mechanism matches fixed cost recovery. The calculation is essentially a comparison of margin recovery as the difference between actual margin and base margin by rate schedule.

As a result, Black & Veatch believes that the weather normalization equation and factors should be updated in the Company's next rate case to address the fact that a number of factors can over time impact the manner in which weather affects the adjustments to customers' actual gas usage. For example, conservation programs impact weather related changes in usage by reducing heat loss, improving appliance efficiencies and altering the customer response to HDDs. This result may necessitate changing the balance point for requiring heat in the customer's home. In other words, the traditional definition of HDDs based on 65 degrees Fahrenheit may need to be reconsidered. In addition, the measure of the marginal response to temperature variations most certainly changes over time (e.g., consider the impact of the average furnace and water heater life on use per customer). Assuming an average life of 20 years for a furnace and 10 years for a tank style water heater, the appliance replacement rate per year on average is 5 percent for furnaces and 10 percent for water heaters. Since the newer appliances are much more efficient than the appliances replaced, the marginal response to weather will change. By recalibrating the use per HDD factors at least once every five years, the resulting CAP adjustments will better reflect the actual gas usage characteristics of the Company's customer base.

Where growth occurs more rapidly in a sub-area of the Company's service area, the rapid change in housing stock as reflected by the percent of homes built to the most current building code standards will also change the customers' marginal response to weather. In addition, the implementation of tankless water heaters changes the pattern of peak hour loads because of its different usage pattern and impacts the capacity planning for a sub-area of its gas system. When the utility's <u>peak hour</u> load grows, system capacity including pipeline, storage, transmission and distribution capacity are all affected even though the <u>design day</u> capacity may not change. It is important to understand the dynamics of the utility's gas system to assure safe and reliable service to customers. By updating the utility's weather and gas sendout models for design day and design hour load conditions, a current picture of the impacts of conservation and weather on customers' gas usage will permit a more accurate assessment of the underlying costs and resulting benefits.

With regard to unbilled revenues, Black & Veatch understands that this measure needs to be included in the Company's financial reports. However, we do not believe that there is a demonstrated need to include an unbilled adjustment as part of the underlying computation of CNGC's decoupling mechanism.

Black & Veatch observed similar results in the Company's Commercial Rate 104 rate class. The above discussion equally applies to that class—with one added condition. Rate 104 is likely less homogeneous than the Company's residential class. This issue was noted by Company representatives who stated that it may be worth looking at how homogeneous the Company's commercial group is, and the appropriateness of having different levels of margin recovery for different commercial sub-groups (i.e., the current decoupling mechanism is based on a usage assumption of 3,200 therms/year for all commercial customers). This suggests that disaggregating this class into a small sub-class and one or more larger sub-classes may improve cost matching and result in more efficient rates.

A few stakeholders noted that they preferred NWNG decoupling mechanism because it provides weather adjustments within each of the utility's billing cycles. Under the NWNG mechanism, adjustments are made in each monthly billing cycle, based upon the actual weather (i.e., HDDs) experienced during that time period. In other words, there is no delay between the time when the actual weather is experienced and the rate adjustment is made. When Black & Veatch discussed this issue with Company representatives, they stated the Company's billing system that was in place when the decoupling mechanism was implemented did not have the ability to make real-time adjustments for weather. Therefore, it was agreed that weather adjustments would be made based upon weather during the previous year. The Company further noted that the new billing system currently being installed by CNGC also will not be able to accommodate billing cycle-based weather adjustments due to this system feature not being cost-effective given Cascade's small customer base in Oregon.

Under real-time recovery, the weather component of the CAP adjustment would be added to each cycle bill. There are several advantages for both customers and the Company from this approach. When weather is colder than normal, the weather adjustment component helps reduce customer bills by partially offsetting the greater level of purchased gas costs associated with customers' higher gas usage. During warmer than normal cycles, customers pay slightly more for fixed delivery service, but have lower overall bills because of their gas cost savings with lower usage. The net result is the creation of more stable bills for customers. The use of a real-time adjustment also eliminates issues of cross-subsidy because each customer is assessed a rate adjustment for the variation in revenues caused by the weather at approximately the same time at which the variation occurred. When the weather adjustment is deferred for an extended period of time, future customers are assessed rate adjustments that reflect past revenue variations. As a result, there is a potential to exacerbate winter bills when a colder than normal season follows a warmer than normal season. In addition, given the weather differences for the three sub-areas of the CNGC service area, there is the possibility of cross-subsidies between areas caused by the deferral account that would not exist for real-time weather adjustments. Table 3-3 illustrates that the Bend and Baker/Ontario sub-areas had different patterns of gas usage resulting in an implicit cross-subsidy between the two sub-areas. The same is also true for the Pendleton sub-area.

Table 3-3
Heating Degree Day Comparisons for Bend and Baker/Ontario

Sub-Area	Normal HDD	2006	2007	2008	2009
Bend	6,689	6,576	6,450	5,982	6,571
Percent of Normal	--	98.1%	96.4%	89.4%	98.2%
Baker/Ontario	7,155	7,378	7,104	6,976	7,565
Percent of Normal	--	103.1%	99.3%	97.5%	105.7%
Pendleton	5,294	5,264	5,320	4,961	5,594
Percent of Normal	--	99.4%	100.5%	93.7%	105.7%

In two of the four years, Baker/Ontario has been colder than normal while Bend has been warmer than normal in all four years. For the Company's system average weather weighted by customers, the system has been warmer than normal in three of the four years. In two of those years, customers in the Baker/Ontario area would have paid a greater share of the system short-fall in fixed cost revenue through the decoupling mechanism because of higher than average usage, thus creating an unintended cross-subsidy. Using real-time weather adjustments by sub-area is a sound alternative for eliminating this cross-subsidy. Therefore, Black &

Veatch believes that the use of real-time weather adjustments in the Company's CAP mechanism should be considered.

3.2 Mechanism's Impact on Customers

3.2.1 Impact on Customer Bills

The annual bill impact of the Company's decoupling mechanism for the average customer in each of the Company's applicable rate classes is summarized in Table 3-4. The average bill for residential customers and C/I customers is based on actual annual use.

Table 3-4[2]
Decoupling Adjustment and Typical Bills for Residential and C/I Customers

	2006	2007	2008	Total
Residential Decoupling Adjustment	$8.98	($12.17)	$2.17	($1.02)
Residential Total Bill	$955.48	$898.01	$934.76	$2,788.26
Residential Decoupling Adjustment as a Percentage of Residential Total Bill	0.94%	(1.36%)	0.23%	(0.04%)
C/I Decoupling Adjustment	$24.53	($29.65)	$3.63	($1.49)
C/I Total Bill	$3,692.29	$3,537.65	$3,628.38	$10,858.31
C/I Decoupling Adjustment as a Percentage of C/I Total Bill	0.66%	(0.84%)	0.10%	(0.01%)

Based on the above table, the total impact of the adjustments has been very small for the typical bill each year. The annual results follow the expected outcome for the operation of the decoupling mechanism.

From a customer perspective, the residential bill impacts resulting from operation of the Company's decoupling mechanism have been quite small. The greatest impact on the delivery charge portion of the customers' bills in any single year has been less than $0.02 per therm. As a result, it is reasonable to characterize the magnitude of the total CAP adjustment on an annual basis, as minor. Table 3-5 provides the average monthly impact of the Company's decoupling adjustments over a range of bills for each year during the evaluation period.

[2] The 2006 data represents the amounts to be billed in 2007 and so forth.

Table 3-5
Residential Average Monthly Bill Impacts From Decoupling Adjustments

	Therms per Month				
Year	25	50	100	150	200
2007	($0.30)	($0.59)	($1.18)	($1.77)	($2.36)
2008	$0.42	$0.85	$1.69	$2.54	$3.39
2009	($0.07)	($0.15)	($0.29)	($0.44)	($0.58)
2010	$0.45	$0.91	$1.81	$2.72	$3.63

Table 3-6 provides the monthly bills based solely on the gas cost component for each year as a comparison to the decoupling impact on residential customers. The gas cost component at the lowest monthly cost of gas is over 42 times greater than the total decoupling adjustment. This emphasizes the importance of the gas cost component in influencing customer conservation decisions.

Table 3-6
Residential Bills – Gas Costs Only

	Therms per Month				
Year	25	50	100	150	200
2007	$22.56	$45.12	$90.23	$135.35	$180.47
2008	$22.91	$45.82	$91.64	$137.46	$183.28
2009	$23.66	$47.32	$94.63	$141.95	$189.26
2010	$19.08	$38.17	$76.34	$114.51	$152.68

Table 3-7 provides the total monthly bills over the evaluation period as a comparison to the decoupling impact on residential customers shown in Table 3-5. This comparison illustrates the relative inconsequential nature of the decoupling adjustment relative to customers' bills. As a result of the limited magnitude of the deferral accounts resulting from the decoupling mechanism, Black & Veatch does not believe that there is a need to extend the amortization period to lessen the impact on customers.

Table 3-7
Residential Monthly Bills - Total

	Therms per Month				
Year	25	50	100	150	200
2007	$32.98	$62.95	$122.90	$182.85	$242.80
2008	$33.22	$63.44	$123.88	$184.33	$244.77
2009	$34.91	$66.83	$130.66	$194.48	$258.31
2010	$30.54	$58.08	$113.17	$168.25	$223.33

3.2.2 Impact on Low Income Customers

Based on data from the American Community Survey from 2006-2008 for the state of Oregon, it is possible to estimate the impact of the decoupling adjustments on gas customers from the Company's service area using the Public Use Microdata (PUMS) Areas in Oregon that most closely align to the CNGC service area. Recognizing that one of the PUMS areas also includes gas service to customers of Avista Utilities, there is not a perfect match of data to CNGC customers for one of the PUMS areas. Despite the fact that not all customers in the PUMS sample are CNGC customers, we have a profile of various groups of customers based on reported monthly bills and income along with other descriptive data. This data demonstrates that the lowest of low income customers ($10,000 or less of annual household income) had an average gas bill of almost $1,000 per year.[3] The data suggests that customers below the poverty level are likely to have gas usage in excess of the average use per customer. This implies that volumetric recovery of the decoupling adjustments has a disproportionate impact on the rates of low income customers. Since the impacts of the decoupling adjustments were shown above to be small, there should not be a concern over the bill impacts of the decoupling mechanism for the Company's low income segment of customers. However, we believe there is a broader concern related to the impact of volumetric recovery of the fixed cost of delivery service on the Company's customers below the poverty level and the need to eliminate cross-subsidies in the base rates, as discussed in detail below.

The above findings for the Company's low income customers are consistent with other utility studies of similarly situated customers. It is important to recognize that not all low income customers are poor and that not all customers below the poverty level are low income. Figure 3-1 provides the results of a recent study conducted for a Midwest gas LDC based on data available for its entire customer base.[4] Figure 3-1 shows that customers (i.e., households) of this LDC with the lowest incomes use more natural gas than the average customer, and use more gas than all other customers except customers in the two highest income groups. This result is supported by the factors that impact gas usage such as the age of the dwelling, the nature of the thermal envelope, the efficiency of the appliance stock, and other relevant variables such as family size.

[3] The reported usage data includes the impact of a number of customers who self-reported an average monthly bill of $10 which appears to be unrealistically low for a residential gas customer since this bill amount would equate to about 7 therms per month.

[4] It should be noted that this information is used here because the Company does not have consumption information broken down by income levels. Black & Veatch has observed similar results for other LDCs for which we have conducted similar income-consumption analyses.

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Figure 3-1
Average Annual Residential Consumption by Median Household Income
(Calendar Year 2007)

For this LDC, the annual average use per residential customer was 831 CCF. In contrast, low income customers eligible to participate in that LDC's low income programs had an average annual use of 1,109 CCF, or more than 33 percent higher. Other recent studies of utility-specific data confirm the conclusion that customers with income below the poverty level use more gas than the average residential customer. This suggests that the Company should consider alternative revenue decoupling methods that can reduce the impact on customers below the poverty level and target those customers for conservation programs designed to reduce average use per customer. These alternative options are discussed later in this report.

3.2.3 Impact on Conservation Incentives

In the analysis of customer impacts from decoupling, it is also necessary to address issues related to the impact of rate design on conservation incentives. As noted above, the gas cost component of a customer's bill can be viewed as the largest element of the price incentive to conserve. Given that changes in purchased gas costs are typically larger than the Company's decoupling adjustments themselves, there is no evidence to show that the decoupling mechanism itself has had any substantive impact on conservation program incentives; the major impact on conservation appears to be the incentives that are part of the Company's conservation programs.

3.2.4 Impact on Non-Participants

With respect to the belief by some that non-participating customers are penalized by the Company's decoupling mechanism, it must be remembered that its mechanism enables the recovery of the full cost of delivery service, albeit with a one-year time lag. As such, customers are not penalized when rates are based on the utility's underlying costs of delivery service that have previously been authorized by the Commission. Rather, the price signal faced by customers changes, albeit slightly, in the presence of a revenue decoupling mechanism. This impact may be reduced or minimized, however, through real-time weather adjustments and eliminated through alternative rate designs that accomplish the objectives of decoupling.

The potential impact on non-participating customers was a topic in several of the stakeholder interviews that Black & Veatch conducted. One stakeholder noted that for non-participating customers not to have an economic penalty there needs to be a comprehensive set of conservation programs in which all customers could participate. This individual went on to state their belief that Cascade, through the ETO, has such a comprehensive set of programs in place. Company representatives stated that they did not believe an economic penalty exists for its non-participating customers.

By including the decoupling adjustment in rates, customers who do not participate in conservation programs may see slightly higher bills as a result of the Company's decoupling mechanism. Given that during the evaluation period the largest portion of the adjustment was related to weather, which impacts all customers, it is reasonable to conclude that the greater benefit of reduced gas costs under normal weather more than offsets the additional charges associated with the conservation component of the decoupling mechanism. Thus, Black & Veatch believes it is inappropriate to suggest that non-participant customers are penalized under the Company's decoupling mechanism. Although we have discussed the deferred nature of the recovery process and believe a real-time adjustment would be an improvement over the deferral method of matching costs and benefits, in general, the bill impacts arising from the Company's decoupling mechanism should not be viewed as penalties in any sense of the term.

Having addressed the penalty issue, there is a more relevant issue related to potential intra-class subsidies among sub-areas of the CNGC service area. The Company's decoupling adjustment is developed volumetrically so that a greater portion of the total adjustment amount is borne by customers in the Baker/Ontario sub-area, due to this area's higher HDDs. One option for addressing this issue is to treat each sub-area separately for ratemaking purposes.

3.2.5 Impact on New Customer Additions (Including Fuel Switching)

It appears that other factors besides the existence of the Company's decoupling mechanism drive the Company's level of new customer additions. For example, it is reasonable to conclude that the underlying economic conditions in the Company's service area influence new meter installations, as depicted in Table 3-8.

Table 3-8
Meter Installations

	2005	2006	2007	2008
Residential	10,860	9,937	3,023	995
C/I	1,178	1,035	602	431

As the national economy began to decline and, in particular the housing sector, growth slowed in the Company's service area as evidenced by the significant decline in new meter installations shown in Table 3-8. As a practical matter, one would not expect decoupling to have an impact on a utility's level of customer additions. To help explain the Company's trend in customer additions, the potential number of fuel switching customers is also a relevant consideration. It would appear that the Company's decoupling mechanism had no discernible impact on fuel switching, as depicted in Table 3-9, because the fuel switching variability from year to year suggests another underlying cause since the number of fuel switching customers, stated as a percentage of total residential meter installations, declines initially and increases in the last year.

Table 3-9
Residential Fuel Conversions

	2005	2006	2007	2008
Number of Residential Customers	1,984	1,029	350	194
Percent of Total Residential Meter Installations	18.3%	10.4%	11.6%	19.5%

The largest percentage increase in fuel conversions occurred in 2008 when the fewest number of new meters were installed.

3.2.6 Recovery of Fixed Costs From New Customers

One stakeholder questioned whether new residential customers should be continue to be reflected in the computations of the rate adjustments under the Company's decoupling mechanism, noting that new residential customers generally have lower usage due to more efficient housing. As a result, the decoupling mechanism may provide an unintended windfall for the Company relative to authorized margin levels as new customers are added.

Company representatives noted that new customer usage may not be the same as the average existing customer, particularly in the C/I market. The Company also acknowledged that its rates have not been reviewed to determine their relationship to cost of service levels by class since 1986. While rates in total produce the Company's revenue requirements, not conducting a cost of service study over such a long time period (during which time the Company has experienced growth and other factors that may contribute to different levels of class costs) creates uncertainty about the precise treatment of new customers in the decoupling mechanism as a matter of equity. It has not been our purpose to review all of these issues; however, there is a theoretical basis for an equity issue as discussed below. Nevertheless, the Company believed it would be harmed if new customers were excluded from the underlying computations in its decoupling mechanism.

The issue of the impact of the Company's decoupling mechanism on recovery of costs from new customers has many facets. While it has not been our purpose to determine the efficacy of the Company's line extension polices or other factors that may impact the recovery of costs from its new customers, we believe that it is reasonable to summarize the theoretical possibilities. There are a variety of conditions that may result in both over and under-recovery of capital costs for new customers. Table 3-10 summarizes the potential outcomes assuming no contributions-in-aid-of-construction from existing customers.[5]

[5] Black & Veatch notes that the Company's Form 2 reported no contributions-in-aid-of-construction (CIAC), suggesting that the cost of adding a new customer includes the actual cost of connecting the customer to the gas system. Further, if CNGC recovers a contribution and reduces the investment by the CIAC amount, the results of the table are applicable based on the relationship to cost less the CIAC amount.

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Table 3-10
Potential Capital Cost Recovery Outcomes

New Customer	Capital Cost	Usage	Result
1	New Capital Cost > Average Costs in Rates	Higher or lower than average	Under-recovery of costs
2	New Capital Cost < Average Costs in Rates	Higher or lower than average	Over-recovery of costs
3	New Capital Cost = Average Costs in Rates	Higher or lower than average	No over- or under-recovery

Under the decoupling mechanism, all new customers produce revenue equal to the average margin determined in the Company's most recent rate case through a combination of the delivery charges and decoupling mechanism adjustments that provides average base revenue per customer. Referring back to the discussion of the mechanism, actual revenues are adjusted to the monthly expected commodity margin per customer for that month. Thus, new customers must by definition produce the same average revenue recovered per customer in the most recent rate case. The only event that allows the utility to actually recover the capital cost for new customers is if the new customer has capital costs equal to the average cost included in rates. That is, the actual revenue per customer recovers the embedded costs found just and reasonable by the Commission in the last rate case. Thus, if the new customer requires more or less investment per customer than existing customers there is a mismatch between costs and revenues. The outcome that keeps the Company at the same return is the least likely of the three options. For new Customer 1 above, the under-recovery of costs is likely if the customer requires a meter, regulator, service line and a main extension. The outcome for new Customer 2 is likely where the customer is attached to an existing main and requires only a meter, regulator and service line. Based on Company data, it is reasonable to assume that new Customer 1 is the more representative of the three outcomes. Table 3-11 illustrates that CNGC adds both main and service line for new customers.

Table 3-11
Growth in Customer Mains and Services

	2005	2006	2007	2008
Customers	57,004	60,516	62,705	63,386
Main in Miles	1,316	1,378	1,445	1,469
Services	57,975	61,043	62,619	63,376
Miles/Customer	0.0231	0.0228	0.0230	0.0232

Since the miles of main per customer is relatively constant over this period, it is reasonable to conclude that new customers require new main extensions. Although this observation is consistent with Black & Veatch's experience at other LDCs, it is confirmed by the Company's actual 2008 and 2009 data discussed below. It is also reasonable to conclude that Cascade under recovers costs from new main extensions because the average cost of new main in 2008 was $136,772 per mile based on the cost of new main in the Company's Form 2. Form 2 does not provide accumulated depreciation by account for distribution plant so it is not possible to precisely determine the embedded cost of main in rate base for 2008. If one assumes that the ratio of accumulated depreciation to total distribution plant is the same as for mains, mains would be about 43 percent depreciated and the resulting cost per mile of main would be $27,514. This means that the decoupling mechanism does not allow the Company to recover the costs associated with new customers. Based on 2008 data, there is a similar result for services. The average cost of a new service line in 2008 was almost $1,500 per service. The average embedded cost of services was $325 per service. Based on this data, it appears that the average new customer costs about $3,000 or more. At this cost, the first year revenue requirement for a new customer would be about $375 but the allowed recovery would be about $272 in 2009. Since the $272 is total revenue, that amount should be reduced by the out-of-pocket expenses associated with a new customer. But, in any case, the Company loses over $100 of earnings per new customer under the decoupling mechanism. The result for 2009 is similar with the average cost of a new residential customer equal to $3,575 per customer. This means even higher losses for new customers in 2009, where the first-year carrying cost would be almost $450 with allowed recovery of $272.

In the evaluation of customer impacts a question was raised regarding spreading these costs across all rate schedules. Black & Veatch believes it is not reasonable to socialize these costs across all customer classes. The costs recovered are maintained within the rate classes where there are conservation programs and where the decoupling mechanism is applied. It would be unreasonable to shift these costs away from those who benefit from and/or cause those costs to be incurred.

3.2.7 Impact on Uncollectible Accounts

Black & Veatch also reviewed the impact of decoupling on the Company's uncollectible accounts. Table 3-12 provides the level and number of uncollectible accounts during this period.

Table 3-12
Cascade's Uncollectible Accounts in Oregon

	2004	2005	2006	2007	2008	2009
Amount	$269,290	$267,088	$335,154	$505,575	$1,234,045	$945,671
Number of Accounts	2,286	2,433	2,973	5,211	5,839	3,874

Based on the data, there appears to be other factors driving uncollectible accounts expense. For 2007, the decoupling adjustment reduced bills and gas costs were unchanged from 2006. Additionally, for 2009, the level of the decoupling adjustment declined from 2008 and gas costs increased, resulting in higher total bills. As a result, it seems reasonable to conclude that factors other than the periodic rate adjustments under the Company's decoupling mechanism impact its uncollectible accounts expense, not the CAP.

3.3 Mechanism's Impact on the Company

Company impacts resulting from its decoupling mechanism cross multiple dimensions such as financial, conservation commitment, staffing resources, regulatory expense, call center impacts, and others. To respond to these issues, Black & Veatch has reviewed a variety of materials provided in response to our data requests. In addition, we have collected other public information related to the Company and conducted interviews of selected Company personnel.

3.3.1 Impact on Fixed Cost Recovery

The financial impact on the Company from its decoupling mechanism includes the ability to offset declines in fixed cost recovery from rates caused by both weather and conservation. Discussions with Company representatives indicated that they view these impacts in a favorable light. The data supports the conclusion that the Company's decoupling mechanism has, in fact, allowed it to recover fixed costs that otherwise would have been unrecoverable in the absence of filing a general rate case. Black & Veatch notes that over the evaluation period the Company's weighted average HDDs have been below normal by about 2.9 percent, which would have resulted in lower fixed cost recovery for the Company in the absence of its decoupling mechanism. In addition, normalized average residential use has declined by over 6 therms per month over the evaluation period.[6] The decline in use per customer for C/I customers has been about 22 therms per month over the evaluation period.[7] Taken together, the fixed cost impact of conservation amounted to $23.51 per residential customer for 2009, and $59.77 annually per commercial customer in 2009. This would translate into about $1.76 million of lost earnings, or 22 percent of net income as reported for 2008. The weather effect on earnings over the evaluation period is relatively small. In addition, the decoupling mechanism effectively eliminates the impact of weather on earnings as it is designed to do. As noted above, the Company's decoupling causes under-recovery of fixed costs for new customers and negatively impacts its earnings.

The gas cost savings for residential customers using 6 therms less per month in 2010 would be almost $55 while the added charges from the decoupling adjustment in the year with the highest adjustment would be less than $12—an average savings of $43 if that rate adjustment applied in 2010.

3.3.2 Impact on Business and Financial Risks

A second financial issue relates to the impact of the Company's decoupling mechanism on risk and, hence, the authorized equity returns established for the Company. A few stakeholders stated that they believe the decoupling mechanism has reduced the Company's overall business and financial risks and, therefore, its authorized rate of return should be adjusted downward by the Commission. Company representatives noted that the Company's return on equity has declined over time but, without the decoupling mechanism, the situation would probably have been worse. The data confirms that, in the absence of the decoupling mechanism, the Company's earned return would have decreased by a greater amount as expected by the Company.

To fully understand the risk issue as it relates to decoupling requires an understanding of the elements that comprise a utility's business and financial risks and their relationship to how it is treated with other comparable utilities. To begin, it is clear that decoupling adjustments impact only one side of the Company's earnings equation, namely utility rate revenues. The decoupling adjustments do not impact the cost or expense risk associated with the Company's earnings. It is not Black & Veatch's purpose in this report to identify and discuss the risks associated with any particular regulatory environment. In general, there is broad recognition in the gas utility industry of the role of full and partial decoupling mechanisms for LDCs. As a result, many of Cascade's peer companies have in place ratemaking provisions (e.g., revenue decoupling, SFV rates, and weather normalization adjustment mechanisms) designed to provide an enhanced opportunity to collect revenues consistent with the level of revenues approved by regulators in their last rate cases. To the extent the authorized equity return for the Company is based on a determination which relies upon financial data of other companies, the effect of revenue recovery from decoupling on the Company's risks is already largely accounted for in the returns of the other companies (as are other risks such as test year and earning stabilization). Therefore, Black & Veatch believes that any adjustment to the Company's authorized rate of

[6] Based on the difference between the normalized residential use reported in the Company's 2005 and 2009 PGA applications.

[7] Since Black & Veatch did not complete an impact evaluation (i.e., billing analysis correcting for weather and other factors) as part of this evaluation, we can not say whether these reductions are due to weather or conservation.

return due to decoupling is unnecessary and inappropriate. Further, Black & Veatch understands that the Company contributes 0.75 percent of revenues (or about $630,000 in 2008, before taxes) to help fund conservation programs as part of the CAP Stipulation. This effectively reduces the earned return for CNGC by the amount of the contribution, and effectively reduces the authorized return prior to the effect of any decoupling adjustment on Company revenues. It is important to recognize that this sizable contribution effectively means that regardless of the authorized return level determined by the Commission, the Company has a diminished opportunity to earn its authorized rate of return. In Black & Veatch's view, there is no justification for reducing the Company's authorized return on equity based on the operation of its decoupling mechanism. In addition, as noted above, the mechanism contributes to earnings attrition based on customer growth. Further, the existence of an earnings sharing mechanism creates an asymmetric risk for earnings since the upside is capped based on the sharing mechanism and the downside risk is not limited except by the ability of the Company to file and be granted a rate increase.

From the financial community's perspective, the approval of the Company's decoupling mechanism was important to stabilize earnings, to protect its dividend and to allow CNGC shares to trade in the same price earnings range as other LDCs with smaller market capitalizations. Based on our prior discussions with financial analysts who follow gas LDCs, stabilizing revenues is an important consideration in the valuation of the LDC from a market perspective. Prior to approval of the Company's decoupling mechanism, A.G. Edwards (Edwards) described CNGC regulation as "below-average regulatory support (lack of periodic rate increases, weather normalization riders, consumption trackers, etc.)". Edwards appropriately recognized the importance of a decoupling mechanism as a ratemaking tool that provides CNGC with a reasonable opportunity to earn its authorized return. Having a reasonable opportunity to earn its authorized rate of return is a fundamental right of the utility and an integral part of the regulatory compact. This regulatory principle has its foundations in a Missouri case before the U. S. Supreme Court where Justice Brandeis concluded that a utility is permitted an *opportunity to earn the cost of service* including a return of and on the assets devoted to public service. (Missouri *ex rel.* Southwestern Bell Tel. Co. v. Public Service Commission, 262 U. S. 276, 290-291 (1923) - emphasis added).

3.3.3 *Impact on the Company's Unregulated Businesses*

The Company does not have any unregulated businesses; therefore, our evaluation did not address this issue.

3.4 Conclusion

From a purely computational standpoint, the Company's decoupling mechanism works as designed. The mechanism uses a multi-step process to adjust calendar month data. First, weather normalized sales are calculated for each of the Company's three weather areas by multiplying the monthly number of customers times the difference between normal and actual HDD times the weather sensitive coefficient for the area. Second, the expected monthly normalized commodity revenue per customer (as determined in the Company's most recent rate case) is calculated. This calculation multiplies the total number of residential customers times the monthly commodity margin. The actual commodity margin is determined as the actual commodity sales (net of the current month unbilled calculation) times the applicable commodity charge. The weather adjustment margin is added to or subtracted from the actual revenue to produce a weather normalized margin. The difference between the weather normalized margin and the expected normalized margin is the conservation adjustment.

The Company's filings that Black & Veatch reviewed have accurately implemented the resulting rate adjustments through CNGC's decoupling mechanism, and the Company stated that it is satisfied with the simplicity and recovery basis of the mechanism. The resulting decoupling adjustments have been minor and

Black & Veatch does not believe there is a need to extend the amortization period to lessen the impact on customers, nor should the monthly timing of the rate adjustments be changed. Further, Black & Veatch does not believe that the Company's decoupling mechanism should be extended to CNGC's other rate classes. Black & Veatch also believes that the Company's decoupling mechanism has not led to unfair penalties for customers not participating in conservation programs. Finally, Black & Veatch found no evidence that the Company's decoupling mechanism has created any unanticipated disincentives.

The ultimate test of the current decoupling mechanism remains whether the Company and other Parties believe the mechanism provides an adequate level of fixed cost recovery to completely remove the financial disincentive a utility has to promote conservation. In our interviews, CNGC representatives expressed positive views of the mechanism and believe that it effectively removes the disincentive for the Company to pursue conservation. These individuals also indicated that they saw no reason to have the current decoupling mechanism and rate adjustment process changed. Since the Company's decoupling mechanism is fundamentally sound, there is no reason to recommend a change to it based on the current objectives of the CAP. Company representatives further expressed the view that any changes that would make the mechanism more complex would not result in a better mechanism. Black & Veatch agrees that simplicity has its virtues; nevertheless, we also believe that certain issues pertaining to the ongoing operation of the mechanism should be addressed, as discussed below.

Several other stakeholders commented that they believe the Company's decoupling mechanism is fair to both the Company and its customers as long as the conservation programs are fully funded through the public purpose surcharge, and that the mechanism is generally working as originally intended. No stakeholder comments were received by Black & Veatch that indicated any unanticipated disincentives had been created through the decoupling process.

One point raised by a few stakeholders relates to what is really driving the Company's increased focus on conservation: is it the implementation of the decoupling mechanism, the Commission's directives that are reflected in the Company's IRP, or the initiation of the Company's public purpose funds? Some stakeholders, as well as Company representatives, stated that they believe the decoupling mechanism has, in fact, effectively removed the Company's disincentive to promote conservation. Company representatives correctly noted that participation in the public purpose funding process and the transfer of its conservation programs to the ETO happened simultaneously with the Commission's approval of CNGC's decoupling mechanism. Therefore, they acknowledge that it is not possible to fully separate the impact of the various factors on the Company's level of commitment to conservation incentives.

The Company also noted that the public purpose surcharge is the funding vehicle for conservation, while the decoupling mechanism removes the financial disincentives associated with implementing conservation programs. In that regard, these two ratemaking elements are completely linked from the perspective of the Company, particularly given the fact that LDCs in Oregon are not required to have a public purpose fund. The Company also noted that with regard to the public purpose fund rate of 1.5 percent of revenues; 0.75 percent is funded by ratepayers, and 0.75 percent is funded by shareholders—with the later contribution viewed as the "give back" for the Company being granted margin certainty (not earnings certainty). Based upon the results of this evaluation, Black & Veatch agrees with this conclusion.

As discussed earlier, the decoupling adjustments impact only one side of the Company's earnings equation, namely utility rate revenues produced through volumetric rates. The decoupling adjustments do not impact the cost or expense risk associated with the Company's earnings. To the extent the authorized equity return for the Company is based on a determination which relies upon financial data of other companies, many of whom have some form of revenue decoupling in place, the effect of revenue recovery from decoupling on the Company's risks is already largely accounted for in the returns of the other companies. Therefore, Black & Veatch believes that any adjustment to the Company's authorized rate of return associated with implementation of Cascade's decoupling mechanism is unnecessary and inappropriate. Further, the Company's contribution of 0.75 percent of revenues (or about $630,000 in 2008, before taxes) effectively reduces the earned return for CNGC by the amount of the contribution, and effectively reduces the authorized return prior to the effect of any decoupling adjustment on Company revenues. It is important to recognize that this sizable contribution effectively means that regardless of the level of return on equity authorized by the Commission, the Company has a diminished opportunity to earn its authorized rate of return. In Black & Veatch's view, there is no justification for reducing the Company's authorized return on equity based on the operation of its decoupling mechanism. In addition, as noted above, the mechanism contributes to earnings attrition to the extent there is customer growth in the decoupled rate schedules.

One stakeholder noted that his primary concern is to make sure that the Company's decoupling mechanism is being applied correctly, that only true fixed costs are included, and that the calculation of lost margins is actually based on margins lost "at the margin". Black & Veatch concludes that these concerns have been fully addressed in the Company's decoupling mechanism.

Finally, one stakeholder stated that the evaluation of any decoupling mechanism needs to consider the broader regulatory context within which the mechanism operates. As an example, this stakeholder noted that the Company has an earnings sharing mechanism in place in Oregon. This mechanism has been in place for a number of years and has been modified within the last 18 months. According to this stakeholder, the mechanism has been strengthened from a customer perspective to include tighter bands within which earnings are shared. As a result of this change, the chance of significant over-recovery of costs by the Company due to the decoupling mechanism has been lessened. This stakeholder also noted that the Show Cause Rate Case and the MDU Acquisition Case led to lower authorized returns on equity for the Company. As a result, this stakeholder believes that the overall impact of the decoupling mechanism is balanced for both the Company and its customers when CNGC's entire regulatory picture is considered. Black & Veatch concurs with this conclusion.

As part of our review, Black & Veatch reviewed all regulatory filings related to the Company's decoupling mechanism. Based on our review, Black & Veatch concludes that the Company's decoupling mechanism has been implemented properly and that the resulting rate adjustments have been consistent with the associated tariff provisions. We believe that our review of these filings and their subsequent amendments, indicate that the public interest is protected through the current CAP process. Therefore, Black & Veatch believes that the elimination of the Company's decoupling mechanism would be harmful to the Company, its customers, and the environment.

4.0 OBSERVATIONS REGARDING IMPACT OF DECOUPLING MECHANISM ON CONSERVATION ACTIVITIES

As discussed in Section 2, Cascade previously offered a limited selection of conservation programs to its low income residential customers since 1979 and all residential customers since at least 1981. The public purpose surcharge took effect in May 2006 to help fund the Company's conservation programs and, at the same time, the ETO took over program implementation on July 1, 2006.

The purpose of this section is to summarize Black & Veatch's observations and conclusions regarding the impact of the decoupling mechanism on the Company's conservation programs. It begins with a discussion regarding the impact of the mechanism on customer conservation behavior, followed by a discussion of the impact on the Company's conservation behavior. Next, we provide a discussion regarding the ETO's delivery of conservation programs, followed by a discussion of potential additional conservation programs that could be offered by the Company. Next, we provide additional results from Black & Veatch's residential and commercial surveys not discussed in the earlier subsections.

4.1 Mechanism's Impact on Customer Conservation Behavior

Black & Veatch reviewed qualitative and quantitative data from interviews and program records to determine if there have been higher levels of program awareness and program participation since the implementation of the Company's decoupling mechanism, and higher levels of therm savings. Most of those interviewed in this evaluation felt that customer conservation activity had increased since the decoupling pilot was implemented. These anecdotal responses are supported by the data provided to Black & Veatch. Based on a review of the available data on customer participation rates, it is clear that participation levels increased significantly during the time after the decoupling mechanism was implemented, suggesting that this ratemaking solution has had a measurable effect on participation in conservation programs by Cascade's customers.

4.1.1 Awareness of and Participation in Natural Gas Conservation Programs

Evidence from the customer surveys conducted by Black & Veatch provides some indirect insight into the effect of decoupling and the comparative influence of Cascade's efforts versus those of the ETO at encouraging conservation. Again, these findings are considered an indirect commentary on the effect of decoupling because there has been no direct communication with consumers regarding the decoupling mechanism itself; rather customers have been exposed to messages and programs regarding the conservation behaviors that decoupling is intended to encourage.

First, of the 202 CNGC residential customers surveyed, 10 percent report having participated in natural gas conservation programs. For the non-residential sector, of the 100 customers surveyed, the participation rate was reported at 12 percent (e.g., HVAC and insulation rebates).

Results concerning sources of awareness were mixed. When asked about the source of information that led to participation decisions, residential customers mentioned Cascade 5 to 1 over the ETO, and commercial customers mentioned the ETO 8 to 1 over Cascade. Seventy (70) percent of residential customers surveyed noted sources of influence other than either Cascade or the ETO (e.g., Home Depot, plumbing contractors, etc.), whereas only 10 percent of the C/I customers surveyed mentioned other sources. The ETO's strong name recognition in the C/I sector may be due to more recent efforts by the ETO to step up its outreach to this sector.

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Unaided awareness of specific residential conservation programs offered in the Company's service area was no higher than 5 percent. However, when prompted, recognition was (as would be expected) much higher. These responses are listed in Table 4-1. Customer awareness of incentives for gas water heating was highest in both cases.

Table 4-1
Residential Customer Awareness of Natural Gas Conservation Programs

Program Name	Percent Aware of Program	
	Unprompted	Prompted
Natural Gas Water Heater Rebate Program	5.4%	37.6%
High Efficiency Gas Fireplace Rebate Program	2.0%	9.9%
High Efficiency Gas Furnace Rebate Program	3.5%	23.3%
Home Comfort Package	0.5%	8.4%
Free Home Energy Analyzer	2.0%	16.3%

Among the Company's C/I customers, 6 percent were able to identify a natural gas conservation program without prompting. When they were read a list of energy efficiency programs, recognition was higher for electric programs over gas programs by a ratio of 2 to 1.

These survey results indicate that customer awareness remains quite low among both segments of population served by Cascade (i.e., households and businesses), confirming concerns on the part of Cascade that the ETO's marketing and outreach efforts to date have not been sufficient.

The ETO conducts its own Oregon Residential Customer Awareness and Perceptions Survey, the last report having been published in November 2009. There were only 28 out of 904 respondents that were Cascade customers (refer to Figure 4-1). The researchers followed a census-based sampling approach aimed to achieve 95 percent/±10 percent at the regional level, which is a logical surveying approach. Unfortunately, this does not provide adequate information at the utility sponsor level since Cascade is grouped into the Eastern Region with other utilities.

4.1.2 Participation Levels and Conservation Expenditures

Figures 4-2 (residential) and 4-3 (C/I) show the actual Cascade customer participation levels according to program data provided by the Company.

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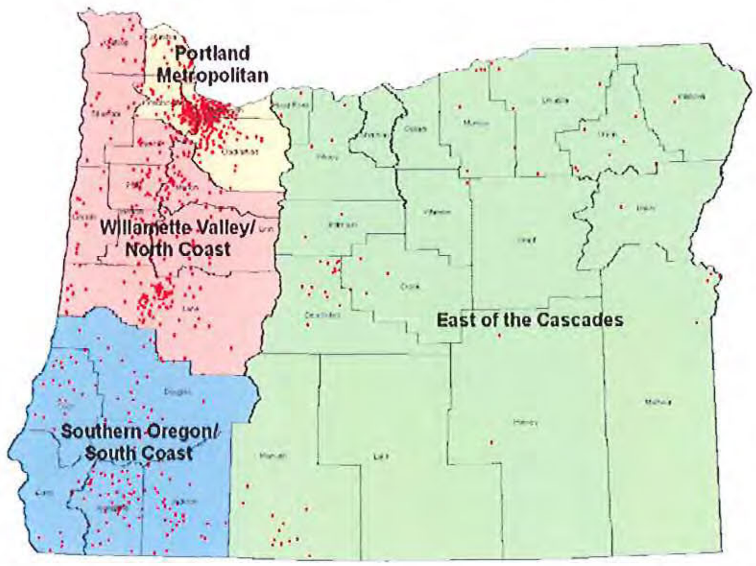
Figure 4-1
Location of Sample Points From 2009 ETO Customer Awareness Survey
(Cascade Customers = 28 points out of 904)



Source: Research Into Action, Inc.; ETO's *2009 Oregon Residential Awareness and Perception Study, Final Report*; November 17, 2009; Figure 2-1; page 4.

Figure 4-2
Residential Customer Participation by Year

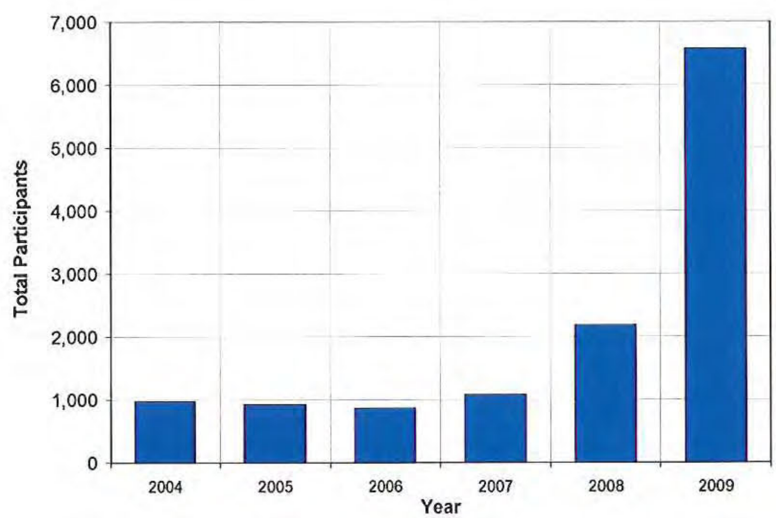


Figure 4-3
C/I Customer Participation by Year

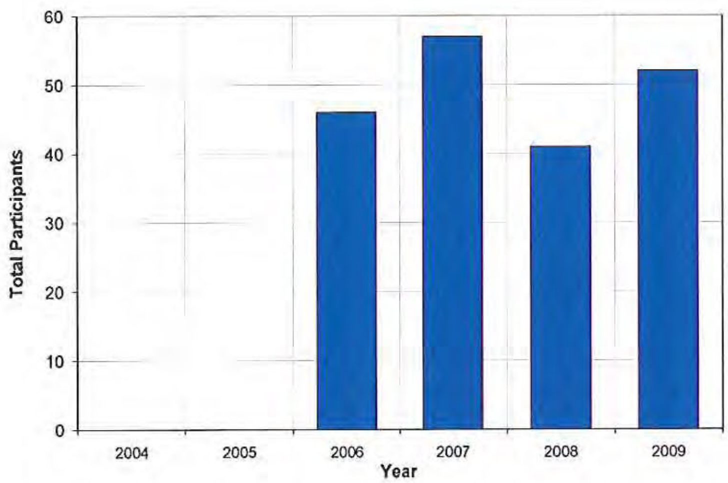


Figure 4-2 clearly shows that residential participation levels increased significantly during the Company's decoupling period.

The C/I data do not show as clear a pattern, as no programs were available to this sector prior to decoupling, and the data do not show an increasing trend since decoupling took effect. Participation by Cascade's non-residential sector has averaged about 50 customers per year since the programs were first offered by the ETO in 2006. The interviews revealed that the ETO was unsuccessful at first in identifying and training adequate numbers of contractors to support the programs in Cascade's service territory, and that training events were either poorly advertised or not offered in locations convenient to this market. The ETO has since increased its efforts to recruit contractors in Cascade's service area to better serve customers. This initial lack of adequate infrastructure for delivery of conservation programs might have contributed to the mixed annual participation levels over the course of this evaluation period.

Consistent with the increasing level of participation in conservation programs by Cascade's customers, the Company's conservation-related expenditures have increased during the evaluation period as shown in Table 4-2.

Table 4-2
Cascade's Annual Conservation-Related Expenditures

Year	Company-Administered Programs			ETO-Administered Programs	Total
	Rebate Programs	Low Income Weatherization	Subtotal		
2004	$374,250	$62,790	$437,040	$0	$437,040
2005	$275,400	$128,340	$403,740	$0	$403,740
2006	$63,650	$9,270	$72,920	$315,330	$388,250
2007	$0	$171,960	$171,960	$934,270	$1,106,230
2008	$0	$181,740	$181,740	$967,080	$1,148,820

These data show that conservation activity has increased and that the increase is coincident with the advent of decoupling in the Company's service area. Another source of information on program participation is available from the 2009 ETO survey noted above. The survey data allow for a comparison of Cascade customer participation versus other companies, both gas and electric. Ignoring the low number of sample points, of the 28 Cascade customers surveyed, the self-reported participation level in the ETO's programs was the second highest among gas customers, with NWNG at 18 percent participation (2009) versus Cascade at 8 percent. Even given this large difference, Cascade's figure represented a doubling in self-reported participation of Cascade customers over 2008, which was 4 percent. Overall participation by gas customers in 2009 was on a par with electric customers, according to the survey results, at 7 percent each.[8]

Based upon the ETO's 2009 Oregon Residential Awareness and Perception Study, general awareness in eastern Oregon (25 percent) is less that in western Oregon (more urban), but awareness among Cascade's customers (which are in eastern Oregon) was 61 percent.

Finally, the 2010 Black & Veatch customer survey, discussed in more detail later in this section, rendered a self-reported participation level of 10 percent among the 202 Cascade residential customers surveyed and 12 percent among the 100 Cascade C/I customers surveyed.

These data show that a key objective of decoupling is being realized in the Company's service area—increased conservation activity—particularly as compared to the participation levels of both electric and other

[8] The ETO noted that its own research indicates customer program participation does not line up very closely with statements of participation from awareness survey respondents, indicating that it appears customers receiving on-site services from weatherization contractors are much more likely to be aware of participating than customers who received ETO rebates for appliances or heating systems. Additionally, the ETO noted that a number of customers who believe they have participated in ETO's programs may not have participated, perhaps due to confusion caused by the existence of State and Federal tax credits. Consequently, the ETO believes that its awareness survey most likely underestimates participation. As a result, the ETO urges caution with regard to using awareness survey data as an indicator of participation, or satisfaction with participation. The ETO stated that, in the future, it will correlate awareness surveys with actual participation as reflected in its program database as part of the reporting process.

gas companies in the region. Increases in conservation activity between 2008 and 2009 were strong among Cascade's customers, indicating that customer participation is moving in the right direction.

4.1.3 Therm Savings

The amount of energy saved by participants is another measure that can be reviewed as evidence of increased conservation activity. One way of looking at therm savings is to compare targets established in the Company's most recent IRP, which was prepared in 2008, based upon a market potential study, against actual achievements.

In its 2008 IRP, Cascade notes on page 28:

> *"Since July 2006, Cascade has relied on the Energy Trust of Oregon (ETO) for the delivery and administration of its conservation programs in Oregon. As mentioned above, 80% of the public purpose funding is transferred to the ETO to design, promote and administer natural gas energy efficiency programs on behalf of Cascade. During 2007, therm savings attributed to Cascade's Oregon service territory amounted to 151,291. Through July 2008, ETO has achieved 49,263 and estimates that 2008 annual therm savings will be approximately 235,660."*

The numbers stated above for 2007 are consistent with updated information provided by Cascade. The Company's conservation programs in total achieved 159,830 therm savings, slightly higher than the 151,291 therms saved as reported in the Company's IRP. However, for 2008, the total savings fell far below the ETO's estimated savings of 235,660 therms. The actual savings were 143,273 therms, lower even than the previous year. This represented a short-fall for the ETO of almost 40 percent of its goal for Cascade's Oregon customers, and a reduction of 5 percent savings when compared to the previous year.

Data for 2009 are shown in Table 4-3 with the target taken from the Company's 2008 IRP, and the actual achieved therm savings figures as provided by Cascade.

Table 4-3
Comparison of Targeted[9] Versus Achieved Therm Savings for 2009

	Residential	Commercial	Low Income	Cascade's Oregon Total
2009 Target	220,597	52,060	10,000	282,657
2009 Actual	139,565	117,044	5,992	262,601
% difference	(37%)	125%	(40%)	(7%)

These data show a continued short-fall relative to the Company's IRP targets although the total savings in 2009 were approximately 88 percent higher than in 2008. The short-fall in 2009 is most likely the result of the economic downturn resulting in customers not having the available funds to spend on discretionary measures. Other factors, such as code changes and the impact of the recession on new construction may also

[9] 2009 target figures are taken from Cascade's 2008 IRP, Table 5-5, page 37.

be responsible for lower customer participation. Savings among existing buildings increased by 63 percent and existing homes by 227 percent, while savings from new buildings, and new homes and products, decreased 21 percent and 42 percent, respectively, from 2008 due to the collapse of the building industry. The ETO expects to increase savings by another 48 percent in 2010. The large savings in the commercial sector were driven by two projects that combined to produce a total of over 45,000 therm savings.

The detailed participant and savings results for each CAP program are provided in Table 4-4, which is based upon data provided by Cascade to Black & Veatch. Green text programs are those provided directly to customers by Cascade and blue represent those programs delivered by the ETO to Cascade's Oregon customers. The table presents participation levels and energy savings per year for Cascade's customers. Average therm energy savings per participant is shown in italics. As noted earlier, 2006 is when the ETO took over delivery of the programs.

The data show that when grouped together, average therm savings per customer has been dropping since the ETO took over delivery of the Company's conservation programs. This appears to be driven largely by the residential sector, where several factors are apparent:

- Change in types of programs offered—high-efficiency furnace and water heater upgrades coupled with weatherization programs[10] that were provided by Cascade from 2004 to 2006 were replaced with new and existing residential home programs and energy kits by the ETO.
- Energy kits—the ETO began distributing low-cost, low-impact energy kits in 2009, resulting in a major downward shift of energy savings per participant in the residential sector. The mailing of these kits are in addition to the ETO's efforts to improve the weatherization of existing homes, which has shown an increase in the number of participants each year with stable average savings per participant.
- New homes—the average therm savings from the new homes program has dropped significantly in each of the last two years. Information was not available as to why this occurred.
- C/I sector programs—in the C/I sector, there was a precipitous drop in average savings per participant between 2006 and 2007, then substantial increases for 2008 and 2009. The 2009 numbers are driven largely by two projects that produced combined savings greater than 45,000 therms.
- Even with the high C/I therm savings, these values did not materially affect the pattern of declining savings per participant for the combined customer group as shown in Table 4-5 due, in large part, to the delivery of energy kits.

[10] Cascade offered "whole house weatherization" programs to income-qualified customers through the Weatherization Assistance Program, and delivered by local CAAs, with rebates provided through this program. All other residential customers were eligible only to receive a basic home inspection complemented by rebates and loans for insulation, windows, and other measures, as appropriate. Rebates were set at a maximum value of 25 percent of the measure cost, not to exceed $350.

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Table 4-4
Conservation Program Participation and Savings by Year

	2004	2005	2006	2007	2008	2009
Residential Programs						
Residential Weatherization Participants	65	28				
Residential Weatherization Therms	8,694	4,780				
Average Therms per Participant	*134*	*171*				
New Homes and Products Paricipants		2	285	747	699	731
New Homes Therms			21,298	113,014	45,846	26,472
Average Therms per Participant			*75*	*151*	*66*	*36*
Existing Homes Participants			32	305	469	632
Existing Homes Therms			1,979	19,199	32,689	32,272
Average Therms per Participant			*62*	*63*	*70*	*51*
Energy Savings Kits Participants						5,165
Energy Savings Kits Therms						74,490
Average Therms per Participant						*14*
Res High-Efficiency Furnace Participants	398	388	247			
Res High-Efficiency FurnaceTherms	38,606	37,636	23,862			
Average Therms per Participant	*97*	*97*	*97*			
Res High-Efficiency Water Heaters Participants	92	88	38			
Res High-Efficiency Water Heaters Therms	2,576	2,464	1,064			
Average Therms per Participant	*28*	*28*	*28*			
Low Income Participants	20	28	17	24	42	42
Low Income Therms	7,437	9,259	6,396	3,574	5,914	5,992
Average Therms per Participant	*372*	*331*	*376*	*149*	*141*	*143*
Total Residential						
Total Residential Participants	575	534	619	1,076	1,210	6,570
Total Residential Therms Saved	57,313	54,139	54,599	135,787	84,449	139,226
Average Therms per Participant	*100*	*101*	*88*	*126*	*70*	*21*
C/I Programs						
Existing Buildings Participants			46	54	29	34
Existing Buildings Therms			49,563	20,081	35,798	58,228
Average Therms per Participant			*1,077*	*372*	*1,234*	*1,713*
New Buildings Participants				3	12	16
New Building Therms				3,962	17,502	13,801
Average Therms per Participant				*1,321*	*1,459*	*863*
Production Efficiency Participants						2
Production Efficiency Therms						47,918
Average Therms per Participant						*23,959*
Total C/I						
Total C/I Participants			46	57	41	52
Total C/I Therms Saved			49,563	24,043	53,300	119,947
Average Therms per Participant			*1,077*	*422*	*1,300*	*2,307*
Total Participants	575	534	665	1,133	1,251	6,622
Total Therms	57,313	54,139	104,162	159,830	137,749	259,173
Average Therms per Participant	100	101	157	141	110	39
ETO Programs Highlighted in Blue						
Cascade Programs in Green						

Table 4-5
Residential, C/I and Total Average Therm Savings Trends

	2004	2005	2006	2007	2008	2009
Residential	100	101	88	126	70	21
C/I	--	--	1,077	422	1,300	2,307
Total Company	100	101	157	141	110	39

4.1.4 Impact on Low Income Customers

Other possible evidence for the drop in average therm savings per participant is provided in the low income program discussion below. Table 4-6 shows that the number of participants in both the weatherization program and the Company's Oregon Low Income Bill Assistance (OLIBA) program increased each year, except in one instance where OLIBA numbers dropped by about 20 families between 2006-2007. Participation in the Company's Weather Assistance Program (WAP) almost doubled in the same time frame.

Table 4-6
Low Income Customer Participation in WAP and OLIBA Programs

	Program Year 05-06	Program Year 06-07	Program Year 07-08	Program Year 08-09
Weatherization Program	28	24	42	42
Oregon Low Income Bill Assistance Program	0	261	244	358

Table 4-7 shows participant and therm savings data for Cascade's WAP.

Table 4-7
Therm Savings by Low Income Participants by Year

	2004	2005	2006	2007	2008	2009
Low Income Therms Saved	7,437	9,259	6,396	3,574	5,914	5,992
Low Income Participants	20	28	17	24	42	42
Average Therms Saved per Low Income Participant	372	331	376	149	141	143

It can be seen that the amount of therms saved per participant among the low income sector dropped by about 60 percent between 2006 and 2007, and has remained at that level ever since. It is unclear why this drop occurred, but it may be due, in part, to the Company's move to the use of the deemed savings methodology, as used by NWNG, as opposed to using REM/Rate audit results prior to 2007.

If the savings values reported to Black & Veatch for 2007 and beyond are in fact from a change in reporting sources, that may explain the reason for the precipitous drop in savings values since 2006, and the relatively constant values ever since. These kinds of considerations would be important in conducting an impact evaluation of the conservation programs, a task that was beyond the scope of this evaluation.

According to the Company's 2008 IRP, as of September 2008, Cascade's Oregon Low Income WAP had served 41 homes and achieved a savings level of 5,277 therms, with a total expenditure of $46,500. However, a balance of $293,660 was still available as of August 30, 2008.[11] Many community agencies that deliver federal WAP services have recently been swamped by increases in WAP funding coupled with American Reinvestment and Recovery Act (ARRA) funding, putting pressure on limited staff resources to deliver services to eligible customers. This may be affecting the amount of savings per participating customer reflected in these numbers above as agencies attempt to deliver services to more customers. In interviews with Company staff, some of whom came directly from the CAA community, it was stated that the Company is working closely with the Oregon Conservation Advisory Group (CAG) to "better understand the capacity of WAP to serve Cascade homes and evaluate strategies designed to increase the level of participation in the program, either through modifications to the program measures, incentives, or delivery approach" (Cascade's 2008 IRP, page 28). The close working relationship between the Company and the CAA community was confirmed during an interview with a CAA agency representative.

4.1.5 Other Factors That May Affect Conservation Savings

Grants received by State and local governments as a result of ARRA funding may have increased public awareness and may have resulted in greater participation in the ETO's programs during this time period. WAP funding also significantly increased in the past year. At the State level, there may be additional tax incentives available for conservation investments (refer to the list of other conservation programs in Appendix E).

Finally, factors reported by customers in the survey as influencing their gas usage and conservation decisions include the costs of natural gas and the weather. Although not identified in the evaluation from the data collected, the economy has also had a significant effect on conservation and usage behaviors in other areas of the country.

4.2 Mechanism's Impact on Company Conservation Behavior

Black & Veatch also examined whether decoupling has led to higher levels of spending by the Company on marketing and outreach to customers, more messages and educational materials for customers related to the benefits of conservation, and processes put into place to facilitate customers' participation in the conservation programs. This outcome is documented above as having indeed occurred. Further, Cascade indicated having devoted considerable time and effort prior to the launch of decoupling on "internal marketing" (e.g., informing employees and stakeholders, such as Community Based Organizations) about decoupling, how it affects the way conservation impacts the Company's bottom line, and how the Company would now be in a position to actively promote conservation as a positive initiative for customers and the Company. Extensive training took place with all customer contact staff regarding the ETO's new role in delivering

[11] Cascade's 2008 IRP, page 28.

conservation programs, the content of the programs, and how customers can take advantage of them. In this regard, it is clear that decoupling succeeded in eliminating the corporate barriers to Cascade's active promotion of conservation.

Another outcome of decoupling that Black & Veatch investigated was the existence of any positive expressions from Company management and staff concerning the elimination of disincentives to conservation behaviors, and acknowledgements of support for such programs.

4.2.1 Marketing and Outreach Levels

Based on our Company and stakeholder interviews, it appears there is wide concurrence that decoupling as a cost recovery mechanism has had a positive effect on eliminating the Company's disincentive for encouraging conservation behavior. One would therefore expect that marketing and outreach for programs would increase, resulting in increased levels of customer participation. One way to gauge this is to look at spending levels during the two time periods. Cascade does not disaggregate its conservation budgets into categories for marketing and outreach, and was thus unable to provide data on the amount of funds expended on conservation program marketing and outreach before and after the implementation of decoupling. However, interviews with Cascade management and staff personnel, and the range and content of print materials reviewed, supports the conclusion that the number, frequency, and content of marketing and outreach had increased significantly after the implementation of decoupling. The participation numbers show that the messages and outreach by Cascade in collaboration with the ETO are working to increase participation levels among both the Company's residential and C/I customers.

Cascade representatives reported that the Company did limited advertising prior to the implementation of decoupling with the exception of bill stuffers focused on the existing customer base (i.e., not load growth oriented). The Company did have some communications with appliance dealers regarding conversions and new customers to encourage they utilized Cascade's conservation programs.

The Company eliminated its Marketing Department in 2005 as part of a reduction in its staffing levels. The Company was experiencing significant growth and believed that additional marketing was not required. "You are better off with direct use, (gas heat, etc.)" was the tag line for one campaign, but the Company also recommended that customers choose high-efficiency units.

Company messaging in 2004 and 2005 showed higher dollars for equipment rebates. It also revolved more around savings and keeping the home warm whereas some later messaging encouraged people to make other improvements (e.g., insulation versus new water heater), to "go tankless", or to track their energy usage on-line. Messages since 2006 were more focused on the ETO programs and were produced largely in collaboration between Cascade and the ETO.

Company information was provided to Black & Veatch that lists 53 separate marketing collaborations that took place from July 2006 to December 2009 between Cascade and the ETO promoting conservation messages and programs. The level of post-decoupling communications is clearly significant and covers a wide range of programs, educational materials, contests, and other communications related to conservation activity.

No evaluation has been done by the Company or was provided to Black & Veatch regarding the effects of the conservation education and marketing initiatives on customer actions taken or behavioral changes.

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Even though Cascade was removed from having direct responsibility for program implementation, the Company clearly has aggressively promoted conservation programs, trained internal staff, and directed customers to the ETO. However, in spite of the high degree of collaboration on print and other media, a few concerns were expressed by Company representatives about the ETO's outreach efforts, including:

- The effectiveness of the ETO's outreach efforts within Company's rural service territory still needs to be improved.
- The ETO has only recently developed a substantive trade ally program in Cascade's service area. ETO representatives stated that they expect that significant increases in savings among Cascade's customers will occur in the next couple of years, now that a more significant contractor network has been established in eastern Oregon.
- The ETO offered slightly different conservation programs to Cascade's customers than what had been available from Cascade.
- The ETO's programs did not adequately address the small manufacturing sector that dominates Cascade's C/I customer base.
- Sponsoring utilities, including CNGC, continue to push for more influence on the ETO's programs and marketing efforts.
- The Company is concerned with the ETO's decreased focus on equipment rebates in favor of behavioral programs (e.g., the ETO is reducing its furnace rebate program to focus only on limited income and multi-family residences) because, according to Company representatives, the ETO believes that portions of the market for these types of programs is saturated. The Company does not believe that this is the case in its service area given the ETO's historical focus on urban areas. The Company would prefer that the ETO remain focused on equipment rebate programs because it believes that the therm savings from these programs are more reliable.
- The Company also noted frustration over the fact that it cannot obtain information from the ETO regarding which of Cascade's customer have participated in the ETO's conservation programs, and which programs they have participated in, in large part due to problems with accessing data from the ETO's data base. ETO representatives expressed similar frustrations and noted that efforts are underway between the ETO, utilities, and the Commission to address deficiencies in the current data sharing procedures.

Cascade has actively monitored ETO's delivery of services to its customers and reports having participated in forums, as well as communicating directly with the ETO about its concerns over ETO's lack of adequate attention to its more rural eastern Oregon customer base with programs that are tailored to the Company's customers. Similarly, the ETO had lagged in its training and recruiting of contractors in the eastern portion of Oregon, and in its development and delivery of programs relevant to Cascade's smaller manufacturing customers, as its existing C/I programs are more targeted to urban commercial customers.

ETO's Oregon Residential Customer Awareness and Perceptions Survey acknowledged some of these findings regarding the lack of effective marketing and outreach to eastern Oregon region customers, which includes Cascade's service territory. A recommendation was made in the report that the ETO better target these customers, who were generally characterized as "less receptive to energy efficiency," with messages by "increasing their awareness of the benefits of taking energy efficiency actions and by targeting low-cost/no-cost actions that could have immediate effects" (i.e., the value proposition versus the green proposition which is more popular in the urban centers). Cascade representatives reported that the Company continues to work with the ETO at addressing these needs, which is further evidence of the Company's more aggressive attitude at encouraging conservation activity.

4.2.2 Organizational Changes

According to Cascade representatives, the Company did not have a conservation-dedicated staff position prior to the implementation of decoupling. Two staff members in its Rate Group shared the conservation activities as part of the Group's other duties. The Rate and Conservation Analyst position is now a dedicated position.

The Company created a Conservation Department in 2006. Efforts in this regard started even before the Company received regulatory approval of its decoupling mechanism. The Company knew that conservation was going to require a greater internal focus, but also knew that it would not be adding a significant number of staff since the ETO was taking over the administration of its programs. The Company also has customer relations and field facilitation people who support its conservation programs.

A Rate Conservation Analyst was added to the Conservation Department in January 2007 and the Company's original low income program manager was transferred and became Manager of the Conservation Department in June 2008. Today, there are three staff members in the Company's Conservation Department: Conservation Director, Conservation Administrator, and Low Income Conservation Administrator.

Related to this issue is the Company's acquisition by MDU, which was noted by some stakeholders as having more influence on the Company's culture than the existence of its decoupling mechanism. One stakeholder noted that the Company has become more risk averse, which affects the ability of the ETO to target specific customers due to privacy concerns. The other factor regarding organization noted by one stakeholder is the need for better clarity regarding decision making within the Company, and which decisions can be made locally versus seeking approval from the parent company.

4.2.3 Employee Attitudes

The effect of decoupling on Cascade as a company differs from its effect on customers in two ways. For customers, the effect is indirect and clouded by the effect of the ETO taking over program delivery. For Cascade' employees, the effect is direct because they were specifically made aware of decoupling and its benefits to the Company. So while the positive responses of customers to conservation efforts cannot be directly credited to decoupling or separated out from the switch to the ETO, the reaction of employees to decoupling is distinct from the switch to the ETO.

Decoupling clearly has had a direct and positive effect on Cascade's embracing of conservation as evidenced by the involvement and messages of employees from senior management as well as Company staff. The staff's understanding and support of conservation is apparent and consistent based on the evidence we have collected. The effect of decoupling on the Company's actions and attitudes is evident in interviews with Company staff, and confirmed in interviews with stakeholders.

Company management personnel stated that the task of ramping up to deliver more conservation programs was daunting given the limited staffing and experience of the Company, so the transfer of program responsibility to the ETO was seen as a welcome and logical decision. The ETO's extensive experience and existing suite of program offerings were also mentioned as positive reasons to transfer the programs to the ETO.

Company representatives did state, however, that they have a concern that Cascade's customers have been underserved by the ETO. The data show that Cascade's customers, in fact, are participating at the same average levels as other utility customers (7 percent average), so this perception was not supported by the data. Even so, the ETO survey did identify eastern Oregonians as being less receptive to energy efficiency messaging promoted by the ETO to date, and there was an acknowledgement in interviews that more could be done. At the same time, Cascade staff members were unanimously supportive of the ETO staff, and indicated that their interactions and responsiveness were positive and improving over time. However, there was still a Company view that the ETO's experience and focus to date has been on urban and suburban consumers and businesses. Interviews with ETO staff confirmed that this was the case originally, but that steps are being taken to better address the needs of Cascade and the different characteristics and needs of its customers for conservation services.

4.2.4 Oregon-Focused Conservation-Oriented Organizations Joined by the Company and Public Appearances

Cascade became a member of the following organizations after the approval and implementation of its decoupling mechanism:

- Member of the Oregon Low Income Advisory Committee (member since May 2006)
- Member of the ETO's Conservation Advisory Council (began participating in November 2006, officially joined the Council in 2007)
- Member of Consortium for Energy Efficiency (member since 2007)
- Participant in meetings and discussions held by the Oregon Energy Coordinators Association (OECA) (participant since 2008)
- Participant in meetings of the Advisory Committee on Energy (ACE) (participant since 2008)

In addition to participation in these organizations, Company representatives have made a number of public appearances in the past couple of years related to the Company's conservation activities, as shown in Table 4-8. In addition to these public appearances, Cascade staff members interact on a regular basis with the ETO, given the ETO's role as the implementer of the Company's conservation programs. This interaction includes attending regular meetings with ETO staff, participation in the ETO's Conservation Advisory Council and Utility Roundtable, and participation in other ETO meetings as appropriate. Additionally, one of the three staff members in the Company's Conservation Department is located in Oregon and interacts frequently with CAAs in addition to the ETO.

Table 4-8
Public Appearances and Statements Related to Conservation Made by Company Representatives

Date	Public Appearances
February 10, 2010	Presentation at Kiwanis in Burlington, Washington to discuss the Company's conservation programs and affirmed the Company's commitment to conservation.
February 4, 2010	National DOE webinar, "The Community Energy Challenge in Whatcom County, Washington." Affirmed the Company's commitment to conservation and strong desire to partner with the energy efficiency community on regional events and initiatives encouraging conservation.
September 26, 2009 (ongoing)	Sponsored and provided pro-conservation messaging and public service announcement (PSA) in support of the "Greenest House" reality show filmed in Bellingham, Washington.
August 18, 2009	Discussion regarding CNGC's conservation programs and commitment to conservation with the Skagit Council of Governments, Washington.
April 22, 2009	Presentation on CIP and low-cost, no-cost conservation measures to Lockheed Martin staff residing near Bremerton Naval Base, Washington.
October 2008	Participated in Purchased Gas Adjustment meeting in Salem Oregon, which included a discussion regarding the Company's conservation programs.
July 2008	Participated in Natural Gas Outlook public meeting in Salem, Oregon, and the Company encouraged customers to take advantage of conservation programs to reduce the impact of the anticipated increase in gas costs.
June 2008	Presented at WAP conference to affirm Company's commitment to LI-WAP and conservation.

4.3 ETO Delivery of Programs

As noted earlier, the ETO assumed responsibility for the delivery of Cascade's conservation programs in May 2006. ETO's 2010 budget includes a significant increase for Cascade's service area according to information obtained during Black & Veatch's interview with ETO representatives, reflecting an increase in its plans to address issues cited elsewhere in this report. The ETO representatives interviewed stated that this budget increase will result in savings more commensurate with the level of the Company's funding of conservation programs.

During Black & Veatch's interviews with Company and stakeholder representatives, we received both positive and negative comments regarding the ETO's conservation efforts. First, the positive comments focused on the ETO's experience in delivering conservation programs, and the fact that they had existing programs in place that could be quickly transferred to Cascade. This approach of having Cascade utilize a statewide program implementation agency addresses the fact that Cascade is small and limited in staff resources. One stakeholder stated that Cascade's decision to use the ETO to deliver conservation programs has allowed it to leverage its offerings in terms of programs offered, delivery mechanisms used, and best practices.[12] Another stakeholder noted that the ETO's delivery of conservation programs, on behalf of Cascade, is much more cost-effective than the Company attempting to implement conservation programs on its own, given that: 1) ETO has established a successful track record; 2) it is able to provide both electric and natural gas programs at the same time; and 3) ETO is able to provide programs and a level of sophistication that CNGC cannot provide due to its size.

The negative comments relate primarily to limitations in the ETO's outreach efforts within the Company's service territory to date, its governance structure and responsiveness to gas company needs, and its branding being seen at times as competing with its utility sponsors.

The following observations can be made concerning the transition to the ETO's programs based on Black & Veatch's interviews:

1. The Cascade and ETO rebate levels were different in many cases, with the ETO's current rebates being generally lower than those that had been offered by Cascade.[13] Cascade indicated it covered the higher rebate payments through a transition phase so as to maintain customer satisfaction.
2. Cascade's low income and weatherization programs delivered through CAAs were fully funded and provided comprehensive weatherization services to low income customers on behalf of the Company at no cost to participants. Cascade also provided insulation rebates to other residential customers. ETO's comparable programs provide rebates for specific measures and equipment instead and thus may result in customers having to cover the balance of project costs.
3. Cascade has offered programs to its C/I customers since November 2005, but there was minimal customer participation prior to the transfer to the ETO in 2006. The ETO programs represent a continued focus by the Company on ensuring that conservation options are available for its C/I customers.

In addition to the ETO programs, Cascade's customers may also be able to participate in other conservation programs offered by their electric service providers, the State of Oregon, or federal agencies. These programs are listed in Appendix E. While Black & Veatch has no program records related to participation by Cascade's customers in these programs, questions on the customer surveys provided some information about the types and sponsorship of programs customers have participated in during the evaluation period.

There are no utility representatives on the ETO Board. Company representatives do not believe that the ETO views itself as an implementation vendor to the utilities, and the contract does not adequately protect utility interests when compared to contracts that would be more typical of an implementation vendor delivering programs for a utility. The struggle that the utilities have had in obtaining any level of participation at the ETO Board level is significant. The ETO was created by the State Legislature and the electric utilities, but was joined voluntarily at a later time by the gas companies. Thus, while it is generally perceived as a positive

[12] It should be noted that Cascade is obligated to use a third-party implementer for its programs, but it does not have to use the ETO. The decision by Cascade to participate in the ETO's programs was considered as the most advantageous for the Company at the time.

[13] Company interview: "Equipment rebate programs and rebate levels were somewhat different (e.g., ETO's levels were lower and efficiency levels were higher). The Company did not want customers to be caught in the middle. The ETO took over after July 1, 2006, but Cascade processed its higher customer rebates for about three months after that."

opportunity for Cascade to have programs delivered on a cost-effective basis to its customers, there remain issues concerning the relationship and value of service rendered by the ETO.

One stakeholder stated that there could be better communication between the ETO and the utilities, and noted that the Utility Roundtable that is being implemented is one approach to improving communications. This stakeholder further stated that the ETO should offer more gas programs and it should have a better understanding of what is occurring in the gas commodity market, noting that gas utilities are more directly impacted by commodity prices than are electric utilities.

Cascade has also been concerned recently about the ETO's promotion of its own brand rather than acknowledging Cascade as a sponsor. Even so, Cascade indicated that its staff works well with the ETO staff, and have worked with them prior to the ETO taking over the Company's conservation programs. The Company is able to express its concerns about receiving an adequate return on the Company's investment in the ETO and that it may not be receiving full value (e.g., trade ally trainings not being convenient to the Cascade service territory). C/I vendors may be more aware of opportunities than residential trade allies since they serve a larger market and can more easily access the ETO training programs.

Another issue regarding the ETO efforts relates to a lack of attention to small manufacturing customers, who predominate in Cascade's industrial sector. The Company's industrial sales customers are eligible to participate in programs delivered by the ETO due to former equity issues. The ETO always was supposed to focus on industrial sales customers, but it was expressed by Company representatives that it has not done so for either Cascade or NWNG. ETO representatives indicated that the ETO has plans to increase its focus on industrial customers over the next few years to rectify this situation.

4.4 Potential Additional Programs

According to Black & Veatch's interviews with ETO staff, the ETO expects that significant increases in savings among Cascade's customers will occur in the next few years, now that a more significant contractor network has been established in eastern Oregon.

Cascade's 2008 IRP refers to a conservation potential analysis that estimates the technical potential associated with cost-effective conservation measures to be approximately 24 million therms in Oregon over the IRP's 20-year planning horizon. The study points to a list of measures that all show reasonable $/therm savings potential, when evaluated on a levelized basis. The conservation measures listed as being the most cost-effective include: (Cascade's 2008 IRP, Table 5-3, page 35)

- Residential Measures
  - AFUE 90 to hydrocoil combo, Z1 and Z2
  - Tank upgrade (50 gallon gas) high-efficiency alternative and new
  - Adding wall insulation
  - Heating upgrade (AFUE 90)
- C/I Measures
  - High-efficiency cooking equipment (new and replacement)

These measures were shown to have the most favorable levelized cost per therm and were all below $0.20/therm installed.

The Company's IRP further identifies areas for future consideration that include the impacts associated with modifications to building codes together with the cost-effectiveness of newer technologies, such as the next generation of high-efficiency water heaters (0.70 efficiency factor) and high-efficiency hybrid heat pumps. The applicability of these measures within Cascade's service territory will be analyzed for potential future incorporation into the Company's conservation program filings.

Aside from which specific measures are feasible, the participation data suggest that the ETO should focus more attention on achieving more comprehensive savings per participant in the residential sector. The level of savings per household participant since the ETO took over suggests that there is significantly more that can be done to achieve higher therm savings per household, at least back to the levels achieved by Cascade prior to 2006. Thus a refocus on comprehensive delivery and less focus on distribution of energy kits would seem called for based on the data.

In terms of new potential conservation initiatives, ETO representatives reported that they would like to see Cascade increase its on-bill financing program to include a level of payment that is linked to energy savings. While the electric utilities are required to do this, it is optional for gas utilities. The ETO would also like to increase the leveraging of Cascade's key account management and government affairs personnel to obtain greater exposure to community groups for conservation outreach purposes. Finally, the ETO would like to increase the number of jointly sponsored presentations made to the community by its staff and Cascade's staff.

The industry experience with on-bill financing programs is mixed. However, other tools do exist that may provide useful information to Cascade customers to help them save energy as well as direct them to existing programs. For example, on-line energy audits and comparative bill products, such as those that provide a customer's consumption data compared to a control group of neighbors' performance, are all gaining popularity as tools to help encourage behavioral changes as well as better direct customers to programs.

The question was posed, "Will decoupling help encourage the continuation of conservation efforts regardless of the fluctuations in the cost of gas?" This evaluation produced no evidence to be able to address this question, as it is speculative. The continuation of Company-sponsored conservation efforts is a matter of regulatory and legislative directive in Oregon at this time and is not associated with the price of energy. That being said, the relationship between the cost of gas and customer conservation efforts is being investigated by Cascade. The Company's 2008 IRP indicates that the "Company continues to explore the incorporation of price elasticity in its future forecasts of demand. The integration of this variable in future demand forecasting models will be dependent upon the practicality of its application and significance of its effect." (Cascade's 2008 IRP, p. 82)

4.5 Additional Information Based on Customer Survey Responses

This subsection provides additional information collected from the residential and C/I customer surveys conducted by Black & Veatch as part of this evaluation dealing with topics other than participation levels and customer awareness of the Company's conservation programs.

4.5.1 Number of Conservation Programs Offered and Potential Savings

As shown in Table 4-9, there is positive agreement among the Company's residential and C/I customers that more conservation programs are available than was the case four years ago, and that participation in these programs would help reduce natural gas bills. However, other survey statements received mixed results from customers indicating that messages are either not being communicated adequately or are not accepted by these groups.

Table 4-9
Customer Survey Results – Number of Conservation Programs Offered and Potential Savings

On a scale of 1 to 5 where 1 = "Completely Disagree" and 5 = "Completely Agree," please rate your level of agreement with the following statements	Residential Responses	C/I Responses
Cascade Natural Gas makes it easier for me to implement conservation measures in my home/business.	2.93	2.91
I am penalized for or get no benefit from implementing energy efficiency improvements in my home/business.	2.30	2.71
The upfront cost of installing energy efficiency improvements outweighs the benefits.	2.95	3.10
Participating in Cascade Natural Gas-sponsored energy efficiency programs will help lower my natural gas bill.	3.50	3.57
Participating in Cascade Natural Gas-sponsored energy efficiency programs can help lower my natural gas usage and lower the amount of my natural gas bill.	3.61	3.64
I would pay more for a higher efficiency natural gas appliance (equipment).	3.21	2.95
I have seen an increase in advertising about natural gas conservation compared to four years ago.	2.93	3.80
There are more programs available to help me reduce natural gas usage in my home compared to four years ago.	3.50	3.62

4.5.2 Impact on Customer Service Ratings

According to satisfaction reports provided by Cascade, residential customer satisfaction levels decreased from 4.5 in 2006 to 4.4 in 2007. Overall customer service ratings increased and then remained the same between 2008 and 2009. Both years had targeted goals of 4.5 on a 5 point scale of satisfaction. The cumulative average for all questions over the course of both years was 4.61.

Black & Veatch's customer surveys asked about customers' perceptions regarding the quality of service received from Cascade post decoupling, and satisfaction with Cascade. The results, shown in Table 4-10, indicate that the majority of customers believe that quality of service has remained the same, but 15 percent of the Company's residential customers and 17 percent of its C/I customers believe it has improved either slightly or significantly. Mean satisfaction scores are also quite positive at 8.05 and 7.72 (on a ten point scale), for residential and C/I customers, respectively. There was no statistically significant difference in the reported level of customer satisfaction between participants and non-participants.

Table 4-10
Customer Survey Results – Quality of Service

"Since 2006, do you think the quality of service from Cascade Natural Gas has improved significantly, slightly improved, remained the same or gotten worse?"		
	Residential Responses (%)	C/I Responses (%)
Improved significantly	5.9%	3.0%
Improved slightly	8.9%	14.0%
Remained the same	81.7%	78.0%
Gotten worse	3.5%	5.0%
"How satisfied are you with the service you receive from Cascade Natural Gas?"		
	Mean Score	Mean Score
Mean score on a 10 point scale with 10 = Very satisfied	8.0	7.7

4.5.3 *Motivations for Conserving or Choosing Natural Gas*

There is no evidence to suggest that the Company's decoupling mechanism has had any direct effect on customer motivations to either use or conserve natural gas, although it has clearly reduced the Company's disincentive to advance cost-effective conservation programs. Rather, the price of natural gas and the weather appear to be key motivators of customers' gas usage. The customer surveys asked respondents about the level of importance of various factors in encouraging conservation behaviors and gas usage; Figures 4-4 and 4-5 show the results.

Figure 4-4
Customer Survey Results – Factors That Impact Amount of Gas Used by Residential Customers

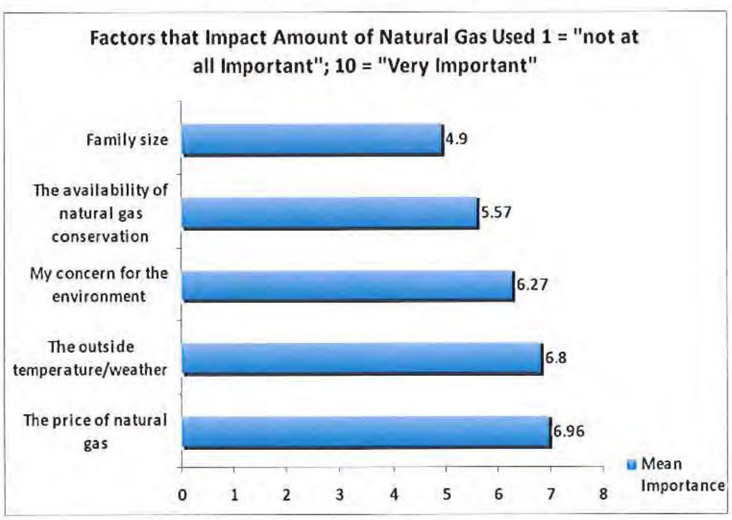
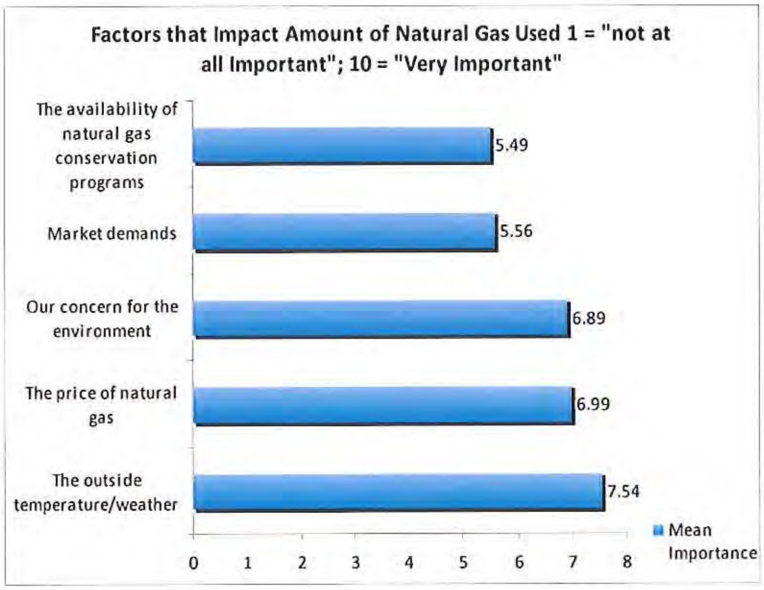


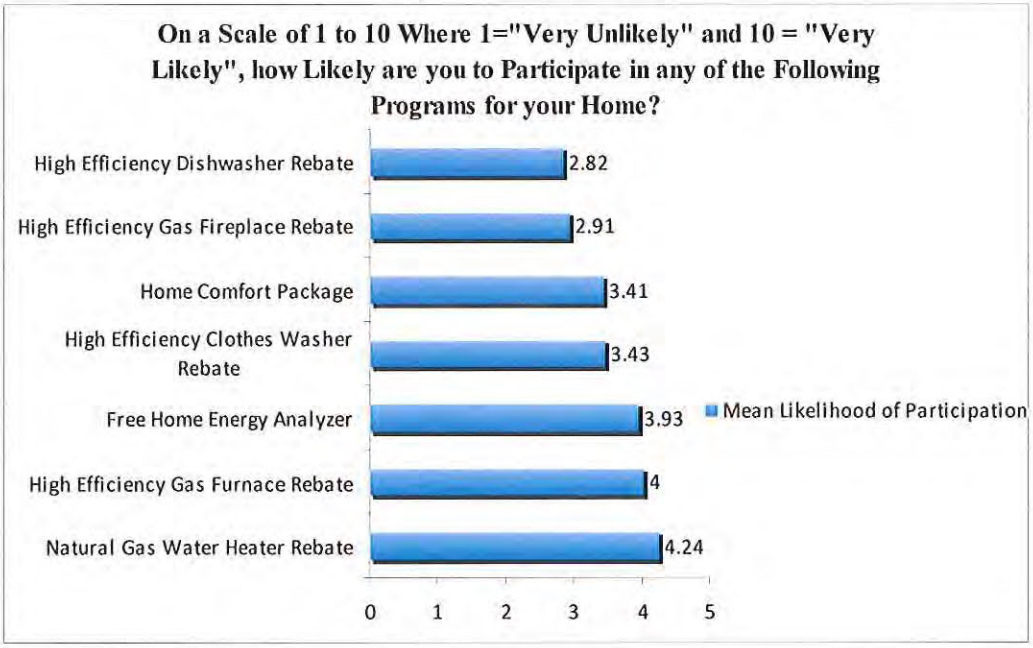
Figure 4-5
Customer Survey Results – Factors That Impact Amount of Gas Used by C/I Customers



4.5.4 Sales of Energy Efficient Appliances

Black & Veatch's evaluation did not include obtaining sales data in the Company's service area related efficient appliances. Data on participation in appliance programs discussed earlier provides an indication of high-efficiency appliance purchases before and after the implementation of decoupling. In addition, customers responding to the survey indicated their future intentions regarding taking conservation actions. Respondents were also asked to indicate their intentions to participate in conservation programs in the future, several of which include the purchase of high efficient gas appliances. The answers are summarized in Figure 4-6 below.

Figure 4-6
Customer Survey Results – Likelihood of Participating in Residential Programs



These findings in Figure 4-6 show that, on average, respondents are most interested in natural gas water heater upgrades but that, in all cases, the mean likelihood of participation fell below a score of 5, which would be neutral. This suggests that Cascade's customers are on balance relatively conservative in their intentions toward conservation investments, as compared to their more urban counterparts based on a review of other surveys.

4.6 Conclusions

Black & Veatch reviewed qualitative and quantitative data from interviews and program records to determine if there have been higher levels of program awareness and program participation since the implementation of the Company's decoupling mechanism, and higher levels of therm savings per participant. Most of those interviewed in this evaluation felt that customer conservation activity had increased since the decoupling pilot was implemented. These anecdotal responses are supported by the data provided to Black & Veatch. Based on a review of the available data on CNGC customer participation rates, it is clear that participation levels increased significantly during the time after the decoupling mechanism was implemented, suggesting that this ratemaking solution has had a measurable effect on participation in conservation programs by Cascade's customers.

Of the 202 CNGC residential customers surveyed, 10 percent report having participated in natural gas conservation programs. For the non-residential sector, of the 100 customers surveyed, the participation rate was reported at 12 percent (e.g., HVAC and insulation rebates).

Survey results indicate that customer awareness remains quite low among both segments of population served by Cascade (i.e., households and businesses), confirming concerns on the part of Cascade that the ETO's marketing and outreach efforts to date have not been sufficient.

Participation in conservation programs by Cascade's residential customers steadily increased during the evaluation period. The C/I data do not show as clear a pattern, as no programs were available to this sector prior to decoupling, and the data do not show an increasing trend. In total, conservation activity has increased, coincident with the advent of decoupling in the Company's service area. Consistent with the increase in Cascade customer participation in conservation programs, the Company's conservation-related expenditures have increased during the evaluation period. As conservation results in lower energy usage, the increased savings resulting from the Company's conservation programs have a direct positive impact on the environment.

Total therm savings has increased significantly during the evaluation period, although savings per participant levels have decreased and total savings have fallen short of the targets established in the Company's 2008 IRP although the total savings in 2009 were approximately 88 percent higher than in 2008. The short-fall in 2009 is most likely the result of the economic downturn resulting in customers not having the available funds to spend on discretionary measures. Other factors, such as code changes and the impact of the recession on new construction may also be responsible for lower customer participation. Furthermore, the amount of therms saved per participant among the low income sector dropped in half between 2006 and 2007, and has remained at that level ever since. It should be noted that the Company began using the deemed savings approach to estimating savings in 2006, similar to the methodology used in NWNG's conservation programs, whereas prior estimates were taken from REM/Rate audit results. This change in estimating methodology may have also impacted the level of reported savings.

Black & Veatch also examined whether decoupling has led to higher levels of spending by the Company on marketing and outreach to customers, more messages and educational materials for customers related to the benefits of conservation, and processes put into place to facilitate customers' participation in programs. This outcome is documented above as having indeed occurred. However, in spite of the high degree of collaboration between the Company and the ETO on print and other media, a few concerns were expressed by the Company about the effectiveness of the ETO's outreach efforts.

Prior to the implementation of the decoupling mechanism, the Company did not have a conservation-dedicated staff position. Since then, the Company created a Conservation Department in 2006. Today, there are three staff members in the Company's Conservation Department including its Director.

Decoupling clearly has had a direct and positive effect on Cascade's embracing of conservation as evidenced by the involvement and messages of employees from senior management as well as Company staff. The staff's understanding and support of conservation is apparent and consistent based on the evidence we have collected. Furthermore, since the implementation of the decoupling mechanism, the Company has joined and participates in a number of conservation-oriented organizations.

During Black & Veatch's interviews with Company and stakeholder representatives, we received both positive and negative comments regarding the ETO's conservation efforts. First, the positive comments focused on the ETO's experience and cost-effectiveness in delivering its programs, and the fact that they have existing programs in place that could be quickly transferred to Cascade. This approach of having Cascade

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utilize a statewide program implementation agency addresses the fact that Cascade is small and limited in staffing resources. The negative comments relate primarily to limitations in the ETO's outreach efforts within the Company's service territory to date, its governance structure and responsiveness to gas company needs.

Cascade's 2008 IRP refers to a conservation potential analysis that indicates that over the IRP's 20-year planning horizon the technical potential associated with cost-effective conservation measures to be approximately 24 million therms in Oregon. As a result, significant additional conservation potential exists in the Company's Oregon service territory.

According to reports provided by Cascade, residential customer satisfaction levels decreased from 4.5 in 2006 to 4.4 in 2007. Overall customer service ratings increased and then remained the same between 2008 and 2009. Black & Veatch's customer surveys asked about customers' perceptions regarding the quality of service received from Cascade post decoupling indicate that the majority of customers believe that quality of service has remained the same, but 15 percent of the Company's residential customers and 17 percent of its C/I customers believe it has improved either slightly or significantly. There was no statistically significant difference in the reported level of customer satisfaction between participants and non-participants.

5.0 RECOMMENDATIONS

The purpose of this section is to provide Black & Veatch's recommendations resulting from its evaluation.

5.1 Decoupling Mechanism Structure

1. The Company's decoupling mechanism should be made permanent. Furthermore, the decoupling rate adjustments should continue to apply only to the Company's residential and general service rates—where there is both significant heat sensitive load and the availability of targeted conservation programs. At the same time, some potential modifications to the Company's decoupling mechanism, as described below, should be considered for implementation in the Company's next rate case filing.
2. Review and revise the use per HDD factors utilized in the Company's weather normalization equations and factors in its next rate case. Given the impact of conservation programs, natural gas appliance replacements, differential growth rates by sub-area of the Company's service territory, and the changing mix of customers, Black & Veatch believes that it is appropriate to recalibrate the Company's weather normalization models. As discussed in Section 3, the above factors can over time impact the manner in which weather affects the level of adjustments to customers' actual gas usage.
3. Eliminate the use of unbilled volumes in the monthly decoupling adjustment calculations since there is no demonstrated need to have such an adjustment reflected in CNGC's decoupling mechanism.
4. Analyze the Company's Rate 104 class to determine if splitting the class based on meter size and type (or other reasonable basis) would result in two or more sub-groups that exhibit more homogeneous load and cost characteristics. For the small commercial class of customers, it may be useful to divide the current class to more accurately analyze weather and conservation impacts. Currently, the class encompasses a broad range of customers that tend to impact average use differently. It is also reasonable to expect that the load characteristics of some of the larger customers differ from those of the typical or average customer. By segregating the commercial class into two sub-groups based on size, the marginal weather impacts may differ with smaller customers exhibiting characteristics similar to residential customers, and larger customers within the commercial class having their own load characteristics. For some utilities, rates do not distinguish between residential and small commercial customers. Rather, the small general service class includes both residential and commercial customers up to an annual usage threshold. The potential for improving the accuracy of weather and conservation information of by splitting the commercial class in this manner should be further evaluated.
5. An important issue in the operation of any utility revenue decoupling mechanism relates to the timing of the revenue adjustments necessary to recover the utility's fixed costs. Under the Company's decoupling mechanism, all lost revenues are deferred for recovery in the subsequent year's rates. The deferral and recovery aspect of the Company's CAP adjustments should, at a minimum, consider the real-time recovery of the weather adjustment component. Under real-time recovery, the weather component of the CAP adjustment would be added to each cycle bill. There are several advantages for both customers and the Company from this approach. When weather is colder than normal, the weather adjustment component helps reduce customer bills by partially offsetting the greater level of purchased gas costs associated with customers' higher gas usage. During warmer than normal cycles, customers pay slightly more for fixed delivery service, but have lower overall bills because of gas cost savings. The net result is the creation of more stable bills for consumers. The use of a real-time adjustment also eliminates issues of cross-subsidy because each customer is assessed a rate adjustment for the variation in revenues caused by the weather at approximately the same time at

which the variation occurred. When the weather adjustment is deferred for an extended period of time, future customers are assessed rate adjustments that reflect past revenue variations. As a result, there is a potential to exacerbate winter bills when a colder than normal season follows a warmer than normal season. In addition, given the weather differences for the three sub-areas of the CNGC service area, there is a possibility of cross-subsidy between areas with the deferral account that does not exist for real-time weather adjustments.

6. Consider other decoupling methods that reduce the impact on customers below the poverty level and target these customers for conservation programs designed to reduce average use per customer.
7. Consider the possible adoption of SFV rates as an alternative ratemaking method to achieve revenue decoupling for the Company. This ratemaking approach has been adopted in some states and is simple, cost-based, economically-efficient, and does not create any intra-class subsidies.

5.2 Conservation Programs

1. Although participation levels are high and increasing, the extent of awareness of the role of Cascade in the promotion of conservation remains low among residential customers.
2. Further, the next ETO Oregon Residential Awareness and Perception Study should sample by utility to achieve 95 percent / ±10 percent rather than at the regional level, so that accurate findings by utility sponsor can be obtained. The data should also then be reported by utility sponsor so that the ETO and the sponsors can determine whether their customers are being adequately served. Although ETO staff question the cost-effectiveness of increasing the number of awareness survey participants in Cascade's service territory, and has raised issues regarding the value of using awareness surveys as an indicator of participation or satisfaction with participation, Black & Veatch believes that such surveys remain a widely accepted evaluation tool and that a larger sample size would provide data for the Company's service territory at the same level of precision as other sponsoring utilities.
3. The ETO's mailing of energy kits to the Company's customers drove the average residential therm savings numbers per participant down in 2009. Black & Veatch believes that the ETO should refocus its efforts of delivering programs that generate higher savings impacts per participant.
4. The ETO's recommendation that its furnace replacement program be refocused because portions of the market have been saturated is <u>not</u> relevant to Cascade, which has significant additional furnace-related conservation potential within its service area. Black & Veatch believes that the ETO's furnace rebate program should continue to be offered to all Cascade's residential customers.
5. Behavior-based programs are a new trend in the conservation community. While there are several promising new tools (e.g., on-line audits, bill disaggregation, etc.), this next generation of programs may be more relevant for highly energy efficient market segments such as other areas that are being served by the ETO (i.e., the Portland area). It would be of considerable concern if behavior-based programs were to replace or even dominate the portfolio in Cascade's service territory given the remaining opportunities for equipment-based and comprehensive weatherization programs.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 306

Summary of Decoupling Mechanism

Cascade Natural Gas
Summary of Decoupling Mechanism

Line No.		2 months ended Jun-06	12 months ended Jun-07	12 months ended Jun-08	12 months ended Jun-09	12 months ended Jun-10	12 months ended Jun-11	12 months ended Jun-12	12 months ended Jun-13	12 months ended Jun-14	6 months ended Dec-14	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Weather	$47,921.79	$285,601.09	($745,702.09)	($1,881.58)	$641,460.16	($699,275.63)	($192,181.51)	$467,350.81	($293,200.09)	$406,640.75	($83,266.30)
2	Conservation	($9,459.87)	$487,228.38	($444,898.95)	$237,924.68	($1,149,126.76)	$196,654.92	($612,472.32)	($423,012.85)	($1,518,083.05)	($205,316.84)	($3,440,562.66)
3	Total	$38,461.92	$772,829.47	($1,190,601.04)	$236,043.10	($507,666.60)	($502,620.71)	($804,653.83)	$44,337.96	($1,811,283.14)	$201,323.91	($3,523,828.96)
4	CAP Base Adjustment (adjusted during PGA)				$1,013,535.00	$340,427.00	$39,220.00	$316,024.00	$252,212.00	($3,930.00)		$1,957,488.00
5	Overall Change to Customers											($1,566,340.96)

CNG/307
Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 307

Monthly Calculation of Decoupling Deferral Entries

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	0.25897	Commercial Commodity Margin (from tariff sheet - see "Delivery Charge") November through June (typically, unless a rate change occurred out of cycle)												
2	0.35790	Residential Commodity Margin (from tariff sheet - see "Delivery Charge") November through June (typically, unless a rate change occurred out of cycle)												
3	0.25735	Commercial Commodity Margin (from tariff sheet - see "Delivery Charge") July through October (typically, unless a rate change occurred out of cycle)												
4	0.35272	Residential Commodity Margin (from tariff sheet - see "Delivery Charge") July through October (typically, unless a rate change occurred out of cycle)												
7	CASCADE NATURAL GAS CORPORATION													
8	UG 167 CONSERVATION ALLIANCE PLAN													
9	DEFERRED ACCOUNTING DETAILS - TWELVE MONTHS ENDED JUNE 30, 2014													
10	DESCRIPTION													
11	RATE SCHEDULE CNGOR101:		Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
13	Bend (District 41):													
14	Customers	CC&B Report: CA1499 Services Summary	38,674	38,686	38,861	39,167	39,356	39,476	39,589	39,675	39,712	39,766	39,751	39,784
15	Actual DD	G:\Dept\Accounting\GA\GASCOST\Degree Day\2010 NOAA degree days backup	20	13	230	663	857	1,111	935	963	721	581	371	223
16	Normal DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	80	96	263	518	804	1,029	1,042	812	791	627	434	193
17	Difference	=Normal DD less actual DD	60	83	33	(145)	(53)	(82)	107	(151)	70	46	63	(30)
18	Coefficient for therms per DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	0.05080066	0.09376563	0.05087517	0.07744696	0.10492543	0.10732941	0.12074557	0.09484996	0.09381310	0.07533745	0.06722508	0.07794561
19	Weather normalization adjustment	=Customers * difference * coefficient	117,880	301,076	65,243	(439,838)	(218,861)	(347,429)	511,481	(568,239)	260,785	137,810	168,353	(93,030)
20														
21	Baker - Ont (District 43):													
22	Customers	CC&B Report: CA1499 Services Summary	6,800	6,738	6,783	6,885	6,959	6,999	7,020	7,022	6,983	6,919	6,865	6,799
23	Actual DD	G:\Dept\Accounting\GA\GASCOST\Degree Day\2010 NOAA degree days backup	21	11	231	713	934	1,404	1,216	980	802	644	392	233
24	Normal DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	48	80	265	570	885	1,190	1,228	927	822	600	381	159
25	Difference	=Normal DD less actual DD	27	69	34	(143)	(49)	(214)	12	(53)	20	(44)	(11)	(74)
26	Coefficient for therms per DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	0.06736790	0.06847586	0.03374700	0.05267502	0.07137826	0.08672497	0.08616888	0.08455088	0.07711633	0.05942149	0.04323620	0.03993995
27	Weather normalization adjustment	=Customers * difference * coefficient	12,369	31,836	7,783	(51,861)	(24,339)	(129,895)	7,259	(31,467)	10,770	(18,090)	(3,265)	(20,095)
28														
29	Pendleton (District 42):													
30	Customers	CC&B Report: CA1499 Services Summary	10,384	10,343	10,390	10,558	10,654	10,719	10,729	10,728	10,667	10,580	10,508	10,439
31	Actual DD	G:\Dept\Accounting\GA\GASCOST\Degree Day\2010 NOAA degree days backup	-	-	106	491	786	1,075	924	882	601	412	165	43
32	Normal DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	15	23	145	391	705	952	977	722	626	441	226	71
33	Difference	=Normal DD less actual DD	15	23	39	(100)	(81)	(123)	53	(160)	25	29	61	28
34	Coefficient for therms per DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	(0.03996594)	0.02782935	0.02546783	0.04658607	0.07780318	0.09489629	0.09976422	0.08118349	0.07686288	0.05516884	0.04445257	0.03792334
35	Weather normalization adjustment	=Customers * difference * coefficient	(6,225)	6,620	10,320	(49,186)	(67,142)	(125,115)	56,730	(139,350)	20,497	16,927	28,494	11,085
36														
37	Total Oregon:													
38	Customers	=Bend + Baker + Pendleton customers	55,858	55,767	56,034	56,610	56,969	57,194	57,338	57,425	57,362	57,265	57,124	57,022
39	Baseline commodity margin/customer	Baseline margin from tariff sheets (for eff. period)	$ 4.96	$ 6.62	$ 6.78	$ 13.29	$ 28.12	$ 41.34	$ 48.17	$ 26.34	$ 24.26	$ 15.40	$ 10.43	$ 6.32
40	Expected commodity margin	=Customers * baseline commodity margin	$ 277,055.68	$ 369,177.54	$ 379,910.52	$ 752,346.90	$ 1,601,968.28	$ 2,364,399.96	$ 2,761,971.46	$ 1,512,574.50	$ 1,391,602.12	$ 881,881.00	$ 595,803.32	$ 360,379.04
41														
42	Actual therms	=CNGOR101 billed therms +/- net unbilled for CNGOR101	825,384	1,039,692	1,115,395	3,536,979	5,546,284	7,458,142	5,594,916	5,954,510	3,820,037	2,775,832	1,615,375	1,197,324
43	Actual commodity margin	=Actual therms * residential commodity margin (A4 through Oct 11, A2 Nov 11 through Oct 12)	$ 291,129.44	$ 366,720.16	$ 393,422.12	$ 1,247,563.23	$ 1,983,828.56	$ 2,669,269.02	$ 2,002,420.44	$ 2,131,119.13	$ 1,367,191.24	$ 993,470.27	$ 578,142.71	$ 428,522.26
44	Weather normalization adjustment	=Bend + Baker + Pendleton weather normalization adjustment	124,024	339,532	83,346	(540,885)	(310,342)	(602,439)	575,470	(739,056)	292,053	136,647	193,581	(102,040)
45	Weather normalized therms	=Actual therms + weather normalization adjustment	949,408	1,379,224	1,198,741	2,996,094	5,235,942	6,855,703	6,170,386	5,215,454	4,112,090	2,912,479	1,808,956	1,095,284
46	Weather normalized commodity margin	=Weather normalized therms * residential commodity margin (A4)	$ 334,875.03	$ 486,479.84	$ 422,819.78	$ 1,056,782.28	$ 1,872,823.53	$ 2,453,656.12	$ 2,208,380.98	$ 1,866,611.06	$ 1,471,716.96	$ 1,042,376.18	$ 647,425.43	$ 392,002.22
47														
48	Margin change due to weather normalization	=Weather normalization adjustment * residential commodity margin (A4)	$ 43,745.58	$ 119,759.68	$ 29,397.66	$ (190,780.95)	$ (111,005.03)	$ (215,612.90)	$ 205,960.54	$ (264,508.06)	$ 104,525.72	$ 48,905.91	$ 69,282.72	$ (36,520.04)
49														
50	Conservation difference-residential	=Expected commodity margin less weather normalized commodity margin	$ (57,819.35)	$ (117,302.30)	$ (42,909.26)	$ (304,435.38)	$ (270,855.25)	$ (89,256.16)	$ 553,590.48	$ (354,036.56)	$ (80,114.84)	$ (160,495.18)	$ (51,622.11)	$ (31,623.18)
51	Weather & conservation	=Margin change due to weather normalization + conservation difference - res	$ (14,073.76)	$ 2,457.38	$ (13,511.60)	$ (495,216.33)	$ (381,860.28)	$ (304,869.06)	$ 759,551.02	$ (618,544.62)	$ 24,410.88	$ (111,589.27)	$ 17,660.61	$ (68,143.22)

Row	A	B	C	D	E	F	G	H	I	J	K	L	M	N
52	CASCADE NATURAL GAS CORPORATION													
53	UG 167 CONSERVATION ALLIANCE PLAN													
54	DEFERRED ACCOUNTING DETAILS - TWELVE MONTHS ENDED JUNE 30, 2014													
55	DESCRIPTION													
56	RATE SCHEDULE CNGOR104:		Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
58	Bend (District 41)													
59	Customers	CC&B Report: CA1499 Services Summary	6,247	6,231	6,235	6,293	6,347	6,382	6,399	6,413	6,386	6,381	6,362	6,344
60	Actual DD	G:\Dept\Accounting\GA\GASCOST\Degree Day\2010 NOAA degree days backup	20	13	230	663	857	1,111	935	963	721	581	371	223
61	Normal DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	80	96	263	518	804	1,029	1,042	812	791	627	434	193
62	Difference	=Normal DD less actual DD	60	83	33	(145)	(53)	(82)	107	(151)	70	46	63	(30)
63	Coefficient for therms per DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	0.108447700	0.340259932	0.197697898	0.233616096	0.299398834	0.347753760	0.418329263	0.307298424	0.303793070	0.231323889	0.207579567	0.237084345
64	Weather normalization adjustment	=Customers * difference * coefficient	40,648	175,973	40,677	(213,171)	(100,715)	(181,988)	286,427	(297,576)	135,802	67,900	83,199	(45,122)
65														
66	Baker - Ont (District 43)													
67	Customers	CC&B Report: CA1499 Services Summary	1,377	1,371	1,373	1,385	1,396	1,405	1,410	1,411	1,405	1,400	1,397	1,390
68	Actual DD	G:\Dept\Accounting\GA\GASCOST\Degree Day\2010 NOAA degree days backup	21	11	231	713	934	1,404	1,216	980	802	644	392	233
69	Normal DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	48	80	265	570	885	1,190	1,228	927	822	600	381	159
70	Difference	=Normal DD less actual DD	27	69	34	(143)	(49)	(214)	12	(53)	20	(44)	(11)	(74)
71	Coefficient for therms per DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	0.22039694	0.54719552	0.22578090	0.21767227	0.27866045	0.37919286	0.39485644	0.38974341	0.32706006	0.23016099	0.16310957	0.15701809
72	Weather normalization adjustment	=Customers * difference * coefficient	8,194	51,764	10,540	(43,111)	(19,061)	(114,012)	6,681	(29,146)	9,190	(14,178)	(2,507)	(16,151)
73														
74	Pendleton (District 42)													
75	Customers	CC&B Report: CA1499 Services Summary	1,785	1,774	1,788	1,811	1,831	1,841	1,849	1,847	1,834	1,830	1,825	1817
76	Actual DD	G:\Dept\Accounting\GA\GASCOST\Degree Day\2010 NOAA degree days backup	-	-	106	491	786	1,075	924	882	601	412	165	43
77	Normal DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	15	23	145	391	705	952	977	722	626	441	226	71
78	Difference	=Normal DD less actual DD	15	23	39	(100)	(81)	(123)	53	(160)	25	29	61	28
79	Coefficient for therms per DD	Fixed - If changing Regulatory (Kathie Barnard) will provide numbers	(0.21348280)	0.28064732	0.25837334	0.26028764	0.39414395	0.49207759	0.49323311	0.38902611	0.33737292	0.21604548	0.13871325	0.10735644
80	Weather normalization adjustment	=Customers * difference * coefficient	(5,716)	11,451	18,017	(47,138)	(58,456)	(111,428)	48,335	(114,965)	15,469	11,466	15,442	5,462
81														
89	Total Oregon													
90	Customers	=Bend + Baker + Pendleton customers	9,409	9,376	9,396	9,489	9,574	9,628	9,658	9,671	9,625	9,611	9,584	9,551
91	Baseline commodity margin/customer	Baseline margin	$ 22.66	$ 25.79	$ 27.13	$ 45.27	$ 74.06	$ 115.23	$ 141.02	$ 84.09	$ 67.60	$ 46.39	$ 34.64	$ 23.04
92	Expected commodity margin	=Customers * baseline commodity margin	$ 213,207.94	$ 241,807.04	$ 254,913.48	$ 429,567.03	$ 709,050.44	$ 1,109,434.44	$ 1,361,971.16	$ 813,234.39	$ 650,650.00	$ 445,854.29	$ 331,989.76	$ 220,055.04
93														
94	Actual therms	=CNGOR104 billed therms +/- net unbilled for CNGOR104	763,403	1,089,641	1,101,995	2,317,177	3,523,722	5,024,705	4,122,749	4,032,200	2,642,789	1,805,820	1,159,830	983,326
95	Actual commodity margin	=Actual therms * commercial commodity margin (A3 July through Oct 10, A1 Nov 10 through June 11)	$ 196,461.76	$ 280,419.11	$ 283,598.41	$ 596,325.50	$ 912,280.72	$ 1,301,247.85	$ 1,067,668.31	$ 1,044,218.83	$ 684,403.07	$ 467,653.21	$ 300,361.18	$ 254,651.93
96	Weather normalization adjustment	=Bend + Baker + Pendleton weather normalization adjustment	43,127	239,188	69,234	(303,420)	(178,232)	(407,427)	341,443	(441,688)	160,461	65,187	96,135	(55,811)
97	Weather normalized therms	=Actual therms + Weather normalization adjustment	806,530	1,328,829	1,171,229	2,013,757	3,345,490	4,617,278	4,464,192	3,590,512	2,803,250	1,871,007	1,255,965	927,515
98	Weather normalized commodity margin	=Weather normalized therms * commercial commodity margin (A3)	$ 207,560.37	$ 341,974.24	$ 301,415.82	$ 518,240.27	$ 866,136.89	$ 1,195,736.40	$ 1,156,091.92	$ 929,835.00	$ 725,957.53	$ 484,534.73	$ 325,257.23	$ 240,198.58
99														
100	Margin change due to weather normalization	=Weather normalization adjustment * commercial commodity margin (A3)	$ 11,098.61	$ 61,555.13	$ 17,817.40	$ (78,085.23)	$ (46,143.83)	$ (105,511.46)	$ 88,423.61	$ (114,383.84)	$ 41,554.46	$ 16,881.53	$ 24,896.05	$ (14,453.35)
101														
102	Conservation difference-commercial	=Expected commodity margin less weather normalized commodity margin	$ 5,647.57	$ (100,167.20)	$ (46,502.34)	$ (88,673.24)	$ (157,086.45)	$ (86,301.96)	$ 205,879.24	$ (116,600.61)	$ (75,307.53)	$ (38,680.44)	$ 6,732.53	$ (20,143.54)
103	Weather & conservation	=Margin change due to weather normalization + conservation difference - comm	$ 16,746.18	$ (38,612.07)	$ (28,684.94)	$ (166,758.47)	$ (203,230.28)	$ (191,813.42)	$ 294,302.85	$ (230,984.45)	$ (33,753.07)	$ (21,798.91)	$ 31,628.58	$ (34,596.89)
104														
105	*Monthly Deferral:*													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
106	Weather variance deferral balance	=CNGOR101 & CNGOR104 margin change due to weather normalization	$ 54,844.19	$ 181,314.81	$ 47,215.06	$ (268,866.18)	$ (157,148.86)	$ (321,124.36)	$ 294,384.15	$ (378,891.90)	$ 146,080.18	$ 65,787.44	$ 94,178.77	$ (50,973.39)
107	Conservation Variance Deferral Balance	=CNGOR101 & CNGOR104 conservation difference-residential &commercial	$ (52,171.77)	$ (217,469.50)	$ (89,411.60)	$ (393,108.62)	$ (427,941.70)	$ (175,558.12)	$ 759,469.72	$ (470,637.17)	$ (155,422.37)	$ (199,175.62)	$ (44,889.58)	$ (51,766.72)
108														
109	*Deferred Balance:*													
110	Weather variance deferral balance	=Weather variance deferral balance (cumulative monthly deferral)	$ 54,844.19	$ 236,159.00	$ 283,374.06	$ 14,507.88	$ (142,640.98)	$ (463,765.34)	$ (169,381.19)	$ (548,273.09)	$ (402,192.91)	$ (336,405.47)	$ (242,226.70)	$ (293,200.09)
111	Conservation Variance Deferral Balance	=Conservation variance deferral balance (cumulative monthly deferral)	$ (52,171.77)	$ (269,641.27)	$ (359,052.87)	$ (752,161.49)	$ (1,180,103.19)	$ (1,355,661.31)	$ (596,191.59)	$ (1,066,828.76)	$ (1,222,251.13)	$ (1,421,426.75)	$ (1,466,316.33)	$ (1,518,083.05)
112	Combined	=Weather + conservation cumulative variance deferral balance	$ 2,672.42	$ (33,482.27)	$ (75,678.81)	$ (737,653.61)	$ (1,322,744.17)	$ (1,819,426.65)	$ (765,572.78)	$ (1,615,101.85)	$ (1,624,444.04)	$ (1,757,832.22)	$ (1,708,543.03)	$ (1,811,283.14)
113														
114														
115	*Journal Entry:*													
116	DR: 47OR.1862.20462	OR CAP weather variance deferral	$ 54,844.19	$ 181,314.81	$ 47,215.06	$ (268,866.18)	$ (157,148.86)	$ (321,124.36)	$ 294,384.15	$ (378,891.90)	$ 146,080.18	$ 65,787.44	$ 94,178.77	$ (50,973.39)
117	DR: 47OR.1862.20463	OR CAP conservation variance deferral	$ (52,171.77)	$ (217,469.50)	$ (89,411.60)	$ (393,108.62)	$ (427,941.70)	$ (175,558.12)	$ 759,469.72	$ (470,637.17)	$ (155,422.37)	$ (199,175.62)	$ (44,889.58)	$ (51,766.72)
118	CR: 47OR.4002.4800CP	Residential CAP	$ 14,073.76	$ (2,457.38)	$ 13,511.60	$ 495,216.33	$ 381,860.28	$ 304,869.06	$ (759,551.02)	$ 618,544.62	$ (24,410.88)	$ 111,589.27	$ (17,660.61)	$ 68,143.22
119	CR: 47OR.4002.4810CP	Commerical CAP	$ (16,746.18)	$ 38,612.07	$ 28,684.94	$ 166,758.47	$ 203,230.28	$ 191,813.42	$ (294,302.85)	$ 230,984.45	$ 33,753.07	$ 21,798.91	$ (31,628.58)	$ 34,596.89
120	DR: 47OR.4002.4800	Oct days 1-3 or 10% of total												
121	DR: 47OR.4002.4810	Oct days 1-3 or 10% of total												
122														

CNG/308
Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 308

Decoupling Allowed Margin Per Customer

Post-CAP filing

R/S 101	0.39393
R/S 104	0.30708

Cascade Natural Gas Corporation

Calculation of Baseline Monthly Commodity Margin Per Customer
Based upon Weather Normalized Therm Sales
As Reflected In The 2013 Purchased Gas Adjustment Application
State Of Oregon

	Adjusted Therms	Actual Customers	Commodity Margin	Baseline Avg Commodity Margin/cust
Residential Rate Schedule 101				
Jan-15	6,279,222	58,276	$ 2,473,573.92	$ 42.45
Feb-15	5,204,359	58,365	$ 2,050,153.14	$ 35.13
Mar-15	4,280,227	58,345	$ 1,686,109.82	$ 28.90
Apr-15	3,069,405	58,219	$ 1,209,130.71	$ 20.77
May-15	1,995,676	58,101	$ 786,156.65	$ 13.53
Jun-15	1,192,714	58,023	$ 469,845.83	$ 8.10
Jul-15	891,898	57,925	$ 351,345.38	$ 6.07
Aug-15	903,157	57,961	$ 355,780.64	$ 6.14
Sep-15	1,307,260	58,265	$ 514,968.93	$ 8.84
Oct-15	2,771,203	58,711	$ 1,091,660.00	$ 18.59
Nov-15	4,821,661	59,250	$ 1,899,396.92	$ 32.06
Dec-15	6,725,246	59,420	$ 2,649,276.16	$ 44.59
Total	39,442,028	700,861	$ 15,537,398.09	**$ 265.15**
Average		58,405		
Commercial Rate Schedule 104				
Jan-15	4,316,841	9,812	$ 224,665.11	$ 23.85
Feb-15	3,534,132	9,819	$ 226,295.66	$ 24.09
Mar-15	2,876,452	9,778	$ 266,729.67	$ 28.32
Apr-15	2,150,029	9,756	$ 462,203.27	$ 48.65
May-15	1,535,037	9,733	$ 831,424.16	$ 86.62
Jun-15	1,059,844	9,708	$ 1,175,561.12	$ 121.82
Jul-15	870,776	9,684	$ 1,117,135.11	$ 115.55
Aug-15	877,972	9,670	$ 915,230.69	$ 94.60
Sep-15	1,039,071	9,688	$ 749,938.63	$ 77.83
Oct-15	1,796,576	9,734	$ 561,448.70	$ 58.41
Nov-15	3,249,697	9,846	$ 401,754.93	$ 41.89
Dec-15	4,599,470	9,859	$ 276,782.69	$ 28.93
Total	27,905,897	117,087	$ 7,209,169.72	**$ 750.56**
Average		9,757		

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 309

Record of Decision (ROD)

MANAGEMENT APPROVAL FORM
Final Approval
Department of Environmental Quality
Western Region

Date: 1/6/14

REPORT/DOCUMENT TYPE:
(Attached)

Record of Decision ____X______

Certification of Completion ______

Other (Describe)______________

Please review the attached document which describes a staff recommendation regarding an environmental cleanup activity. The approved preliminary recommendation has been advertised for public comment as required by ORS 465.320. The public comment period has expired. The attached document includes a discussion of public comments received (if any) and how those comments affected the final recommendation/decision.

FINAL APPROVAL:

______________________________ ______________
Assistant Attorney General (DOJ) Date

Michael E. Kennedy 1/8/2015
Section Manager Date

______________________________ ______________
Regional Administrator Date

______________________________ ______________
Other (Indicate) Date

Return completed form to: Seth Sadofsky
Western Region Environmental Cleanup

RECORD OF DECISION

FOR

EUGENE MANUFACTURED GAS PLANT (FORMER)

EWEB-OWNED PORTION

700 block of E 8th Avenue

T17S, R3W, Section 32, Tax Lots 1500 and 1600, Lane County

EUGENE, OREGON

ECSI 1723

Date: January 5, 2014

Introduction

Soil and/or groundwater contamination associated with operation of the Former Manufactured Gas Plant (MGP) is present on property owned by EWEB, property owned by the University of Oregon, and the cul-de-sac property located southwest of the EWEB property (Figure 1 and 2). This Record of Decision (ROD) is specific to the EWEB-owned portion of the site (herein Site). The EWEB-owned portion consists of approximately 1.5-acres and is dominated by a flat paved lot located at the 700 block of E 8th Avenue, in Eugene, Oregon. Most of the contamination is located in the vicinity of the historical MGP, which was located on the central portion of the Site, within the existing EWEB fence line. The Site is located on the south bank of the Willamette River in a mixed use area neighborhood encompassing commercial, industrial, office, residential, and park land uses.

This ROD prescribes the remedial action for the Site, which is necessary to meet the Site remedial action objectives and protect human health and the environment. The adjacent portions on cul-de-sac property and on University of Oregon property are being addressed in other documents.

Additional information on this Site, including the full Staff Report to which this document refers, can be found at the following web site.

http://www.deq.state.or.us/Webdocs/Forms/Output/FPController.ashx?SourceId=1723&SourceIdType=11

Public Process

A 30-day public comment period on DEQ's recommended remedy was held during September of 2014, as required by ORS 465.320, Notice was published as a legal ad in the Eugene Register-Guard, in the Secretary of State Bulletin, and on DEQ's web site. A link to this notice on DEQ's web site was published through DEQ's GovDelivery service to all who have registered interest in receiving Environmental Cleanup notices. A newspaper article about the Site and proposed cleanup was published in the Eugene Register-Guard early in the public comment period, and an additional article on a related subject mentioned the public comment period. No comments were received during this period.

Summary of Site Investigation Activities

An initial investigation of soils at the Site took place in 1996, which was followed by groundwater investigations in 1998 and other Site work documented in a final Phase I Remedial Investigation Report in 2000. A Land and Beneficial Water Use Survey report was completed in 2000 and the report was supplemented in June 2012. A Human Health Risk Evaluation was submitted to DEQ in 2002 with a supplemental Technical Memorandum in 2003. Ecological risk was evaluated through a Level I Ecological Risk Assessment in 1998 and a Level II Ecological Risk Assessment in 2009. A Draft Focused Feasibility Study (FFS) proposing remedial action alternatives was submitted to DEQ in 2003. and a final FFS was submitted in 2006. An FFS Addendum proposing additional remedial action measures for the shoreline area was completed in 2011. A full discussion of the results of these investigations and relevant data is presented in the Staff Report along with full citations.

Summary of Interim Removal Actions

Several subsurface structures associated with the former MGP operations were evaluated during different phases of the Site investigation. In 1999, it was determined that liquids should be removed from the tar-tank structure (see Figure 2). Between May and November 1999, approximately 1,500 gallons of hydrocarbon liquids were removed from the tank and recycled offsite in accordance with applicable regulations. The liquids were pumped until recovery of liquids was no longer effective or possible, and the standpipes were abandoned and the asphalt cover sealed under DEQ oversight. Approximately 275 cubic yards of contaminated sandy gravel and demolition debris are estimated to remain in the concrete structure. Because hydrocarbon liquids have been removed and the remaining solid waste is contained in the concrete tar tank and covered by the existing asphalt cap, these materials are considered stable under current Site conditions.

Remedial Action Objectives

Based on the results of the remedial investigation and risk evaluations, Remedial Action Objectives (RAOs) were developed by DEQ and EWEB to address the presence of polynuclear aromatic hydrocarbons (PAHs), benzene, cyanide, and total mercury in contaminated soil and groundwater at the Site. These RAOs are:

- Prevent industrial and excavation worker exposure to upland soils containing contaminants of concern (COCs) above the numerical soil remedial action objectives (NRAO)s, and limit future public and worker exposure to contaminated subsurface soil in the shoreline area to acceptable levels.
- Prevent exposure to future Site occupants/workers from vapor intrusion of benzene into indoor spaces above the numerical NRAOs.
- Ensure continued shoreline stability to prevent erosion of upland or shoreline subsurface soil, to prevent the unintentional dispersal of soil contaminants to the Willamette River, and to prevent public and worker exposure to subsurface soil.
- Minimize or control infiltration of rainwater through contaminated soil in upland Site area to prevent mobilization of contaminants to the Willamette River.
- Treat (or excavate and dispose offsite) soil/waste material identified as hot spots, to the extent feasible considering the criterion in OAR 340-122-0085(7) and the balancing factors in OAR 340-122-0090(3).

Revised 1/05/14 SJS

The remedial actions for soil will be guided by numerical remedial action objectives (NRAOs) based on risk-based screening levels rather than Site-specific cleanup levels. Remedial actions based on these NRAOs are protective for the potential exposure pathways listed. Should alternative or contingent remedial actions be considered in the future, Site-specific cleanup levels may be developed in cooperation with DEQ and applied in lieu of the NRAOs. The following numerical remedial action objectives were developed to protect industrial site workers and excavation workers. Remedial action objectives for carcinogenic chemicals are based on a 1 X 10^{-6} cancer risk, while non-carcinogenic chemicals are based on a Hazard Index (HI) of 1. Soils that contain chemicals in excess of remedial action objectives will require action to prevent unacceptable human exposure.

NUMERICAL SOIL REMEDIAL ACTION OBJECTIVES
Eugene Former Manufactured Gas Plant Site

HAZARDOUS SUBSTANCE	INDUSTRIAL CONCENTRATION	DEQ EXCAVATION WORKER CONCENTRATION	BASIS AND PRIMARY EXPOSURE PATHWAY
Cyanide	610	5,100	HI=1 Direct contact
Total Mercury	310	2,600	HI=1 Direct contact
2-Methylnaphthalene	23*	16,000*>Csat	HI=1 Direct contact
Acenaphthylene	23*	16,000*>Csat	HI=1 Direct contact
Benz[a]anthracene	2.7	590>Csat	$1x10^{-6}$ Risk, Direct Contact
Benzo[a]pyrene	0.27	59>Csat	$1x10^{-6}$ Risk, Direct Contact
Benzo[b]fluoranthene	2.7	590>Csat	$1x10^{-6}$ Risk, Direct Contact
Benzo[g,h,i]perylene	23*	16,000*>Csat	HI=1 Direct contact
Benzo[k]fluoranthene	27	5,900>Csat	$1x10^{-6}$ Risk, Direct Contact
Chrysene	270	59,000>Csat	$1x10^{-6}$ Risk, Direct Contact
Indeno[1,2,3-cd]pyrene	2.7	590>Csat	$1x10^{-6}$ Risk, Direct Contact
Naphthalene	23	16,000>Csat	HI=1 Direct contact
Phenanthrene	23*	16,000*>Csat	HI=1Direct contact
Benzene	34	9,500>Csat	$1x10^{-6}$ Risk, Direct Contact

Revised 1/05/14 SJS

NUMERICAL SOIL REMEDIAL ACTION OBJECTIVES Eugene Former Manufactured Gas Plant Site			
HAZARDOUS SUBSTANCE	INDUSTRIAL CONCENTRATION	DEQ EXCAVATION WORKER CONCENTRATION	BASIS AND PRIMARY EXPOSURE PATHWAY
NOTES: The numerical remedial action objective values for soil are risk-based concentrations (RBCs) from DEQ's 2003 RBDM, as updated 2012. Cyanide numerical remedial action objective is from USEPA's Region Screening Level (RSL) Summary Table, May 2011. Direct contact includes soil ingestion, dermal contact, and inhalation. 1) Soil units shown are in mg/kg, or ppm. 2) Cumulative excess cancer risk for all carcinogens shall not exceed $1x10^{-5}$ 3) The soil numerical remedial action objective for benzene in indoor air (vapor intrusion into buildings) is 1.2 mg/kg (DEQ 2003 RBDM, as updated 2012). * Surrogate value based on toxicity data for naphthalene.			

Evaluation of Remedial Alternatives

Four potential remedies were outlined in the FFS and FFS Addendum, they are:

1. No Action
2. Engineering and Institutional Controls
3. Focused Soil and Residuals/Waste Removal at Former MGP Structures and Engineering and Institutional Controls
4. Deep Soil Removal in Core Area, Residuals/Waste Removal at Former MGP Structures, Shoreline Bulkhead Construction, and Engineering and Institutional Controls

These potential remedies were evaluated on the basis of protectiveness, long-term reliability, implementability, implementation risk, and reasonableness of cost, as well as the degree to which they address identified hot spots according to OAR 340-122-090.

Description of Selected Remedy

DEQ has selected the remedial action recommended in its Staff Report as the final remedy for the Site in accordance with Oregon Revised Statutes (ORS) 465.200 et. seq. and Oregon Administrative Rules (OAR) Chapter 340, Division 122, Sections 010 through 115. The recommended remedial action includes several measures to meet the above RAOs, including:

- Excavation and off-site disposal of high-concentration residuals/waste at the first gas plant structure and the small relief holder;
- An assessment and removal for similar residuals/waste from the vaults at the large gas holder;
- Engineering controls consisting of (1) a cap and (2) bank stabilization action;

- Institutional controls consisting of an Easement & Equitable Servitude restricting property use, and development of a site management plan (SMP);
- Inspection and maintenance of the Site conditions and features according to the SMP.

The selected remedy is described in more detail below.

Excavation and off-site disposal of high-concentration residuals/waste

High-concentration residuals/waste will be removed at the two structures previously evaluated (i.e., first gas plant building location and small relief holder foundation) by excavation. This material will be disposed of properly after characterization.

Assessment and removal of high-concentration residuals/waste from vaults at the large gas holder

The two additional vaults at the large gas holder foundation will be assessed during implementation of the recommended removal actions at the other MGP structures. High-concentration residuals/waste and oily liquid, if present, will be removed from these additional structures. Any removed material will be disposed of properly after characterization.

Engineering Controls

Engineering controls will consist of completing an asphalt cap over the upland portion of the Site and implementing bank stabilization measures at the shoreline area. Approximately 90% of the upland area is already capped with asphalt and the remaining portions of the Site will be capped with a minimum of three inches of asphalt. Cap inspection and maintenance will be included in the SMP. EWEB may elect to conduct additional analyses in the future to consider other cap/cover types as long as RAOs are met and any modifications to the cap/cover design are coordinated with DEQ.

The bank stabilization measures will incorporate native vegetation, natural rock and bioengineering treatments at the shoreline area and will be designed to contain and prevent exposure of Site contaminants, and prevent migration of the contaminants to the Willamette River that could result in surface water and sediment contamination exceeding DEQ's acceptable risk levels. The bank stabilization design will consider factors such as flood events and Site and nearby shoreline configuration to ensure protectiveness. The bank stabilization final design will be subject to review and approval by DEQ and, potentially, other state and federal governmental agencies.

Institutional Controls – Easement and Equitable Servitude

A DEQ-approved Easement and Equitable Servitude (E&ES) will be recorded in the county property records with the following general requirements for the Management Area which is the portion of the EWEB property where the remedial action applies as shown on Figure 2:

1. Groundwater Use Restrictions: The Site owner may not extract through wells or by other means or use the groundwater at the Site for consumption or other beneficial use. This

prohibition does not apply to extraction of groundwater associated with groundwater treatment or monitoring activities approved by DEQ or to temporary dewatering activities related to construction, development, or the installation of sewer or utilities at the Site. The Site owner must conduct a waste determination on any groundwater that is extracted during such monitoring, treatment, or dewatering activities and handle, store and manage waste water according to applicable laws.

2. Soil Cap Engineering Control. Except in accordance with the SMP as approved in writing by DEQ, the Site owner may not conduct or allow operations on the Site or use of the Site in any way that will or likely will penetrate the cap at the Site or jeopardize the cap's protective function as an engineering control that prevents exposure to contaminated soil, including without limitation any excavation, drilling, scraping, or uncontrolled erosion. The Site owner will maintain the cap in accordance with the SMP as approved in writing by DEQ. The Site owner shall notify DEQ prior to any subsurface work at the shoreline area or any modification of the bank stabilization measures that might expose human or ecological receptors to hazardous substances at the Site.

3. Land Use Restrictions. The following land use activities are prohibited on the Site; Residential use of any type. The Site owner shall notify DEQ of zoning changes or any development activities or change in use of the Site that might expose human or ecological receptors to hazardous substances at the Site.

4. No buildings for continuous human occupancy shall be constructed at the Site (e.g., offices, shops, retail development) unless additional Site-specific analyses are conducted in the future to demonstrate that RAOs would be met and the analyses are coordinated with and approved by DEQ, and aspects of the building construction to meet RAOs are approved by DEQ.

Institutional Controls – Site Management Plan

A DEQ-approved SMP will be prepared for the Site, which will cover the following general topics:

1. Excavation Worker Health and Safety. The SMP will describe how work shall be conducted at the Site, who may complete the work, what notifications will need to occur prior to work commencing, measures for personal protective equipment and training required to work on the Site, and general protocols for excavating, storing, characterizing, and disposing of any excavated materials from the Site.

2. Cap Maintenance. The SMP will detail how and at what interval the cap will be inspected and outline any regularly scheduled cap maintenance that may be required.

3. Shoreline Inspection and Maintenance. The SMP will detail a shoreline inspection and maintenance plan designed to ensure that conditions in the shoreline area remain stable (i.e., no exposure or release of impacted soils or soil contaminants).

4. Shoreline Area and Bank Stabilization Measures. The SMP will include measures for inspection and maintenance of the shoreline area, including any implemented bank stabilization measures and coordination with the DEQ as required.

5. Reporting. The SMP will detail a simple annual report form to be submitted to the DEQ containing records of excavation work at the Site, cap maintenance/inspection, and shoreline inspection.

Residual Risk

Under the recommended remedial action alternative, the Site risks will meet the protectiveness as required by OAR 340-122-0040 for unacceptable Site risks by applying the following measures.

- **Excavation Worker Scenario.** Risk from this scenario is reduced to acceptable levels through a SMP that will be prepared to direct all future excavation activities.
- **Industrial Worker Scenario.** To address this risk, an asphalt cap will be placed over the upland portion of the Site, and cap inspections and maintenance will be included in the SMP. The Site owner may elect to conduct additional analyses in the future to consider other cap/cover types as long as RAOs are met and any modifications to the cap/cover design are coordinated with DEQ.
- **Potential Future Exposure to Vapor Intrusion to Buildings.** No buildings currently exist at the Site. However, to address the potential for future unacceptable risk regarding commercial building structures, an institutional control will be included in the Easement and Equitable Servitude. Specifically, no buildings for continuous human occupancy will be allowed on the Site (no offices, shops, retail development) unless additional Site-specific analyses are conducted in the future to demonstrate that RAOs would be met, and that the analyses are coordinated with DEQ and aspects of the building construction to meet RAOs are approved by DEQ.
- **Potential Exposure at Shoreline Area.** The recommended remedial action alternative, including the bank stabilization measures, will be designed to prevent or minimize potential exposure of Site workers and visitors to subsurface soil/fill contaminants in the shoreline area and the potential for unintentional dispersal of soil/fill contaminants to the Willamette River surface water and sediment.

Statutory Determination

The selected remedial action for MGP-related contamination at the EWEB-owned portion of the former Eugene Manufactured Gas Plant is considered to be protective, effective, reliable, and cost-effective. The selected remedy also addresses the identified hot spots of contamination to the extent feasible in accordance with OAR 340-122-090. The selected remedy is consistent with the current and future anticipated use of the Site and is protective of current and future anticipated beneficial water use within the Site Locality of the Facility (LOF). Residual risks associated with the selected remedy are below DEQ's acceptable risk levels.

Revised 1/05/14 SJS

Attached
Figure 1
Figure 2

Administrative Record

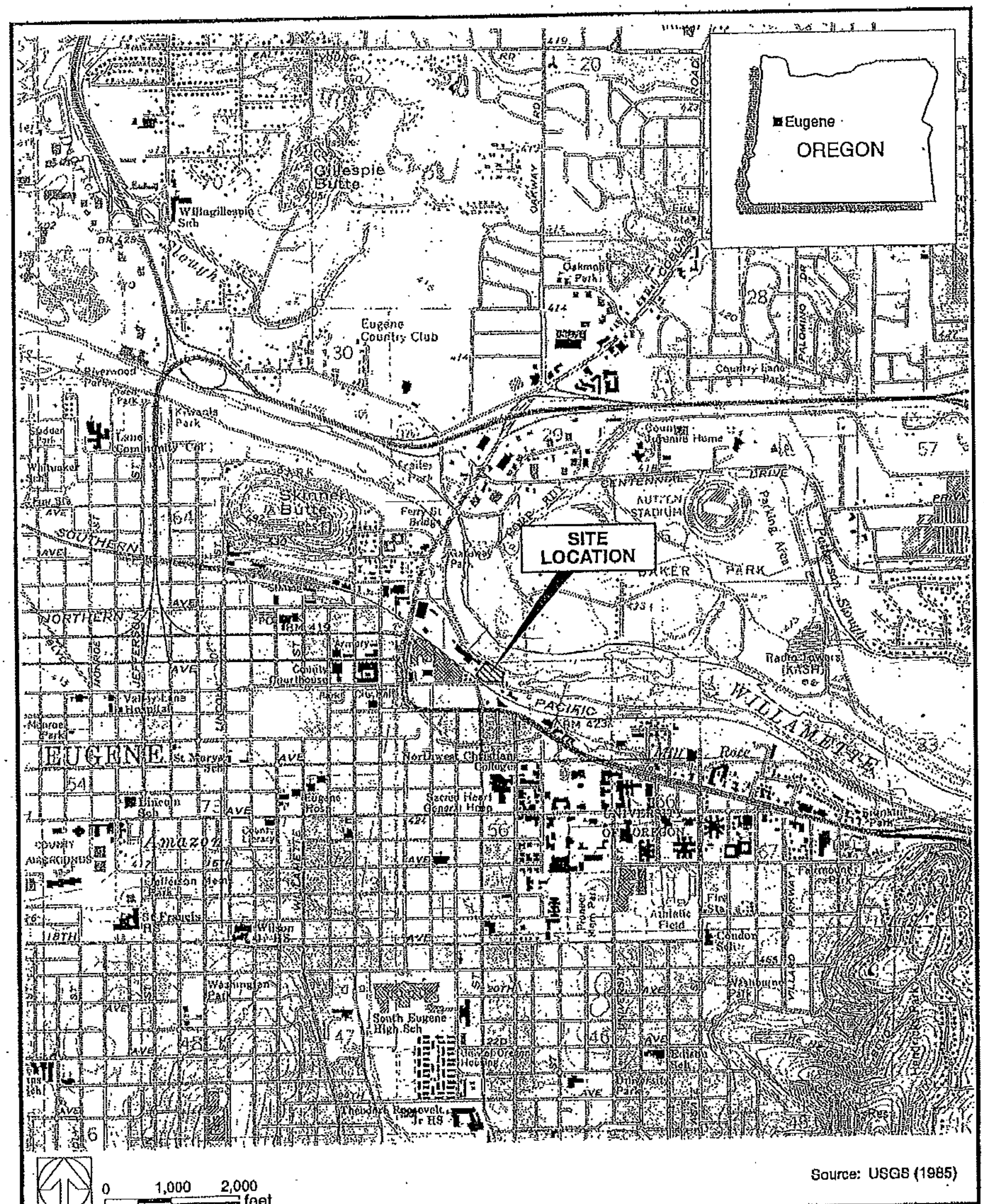
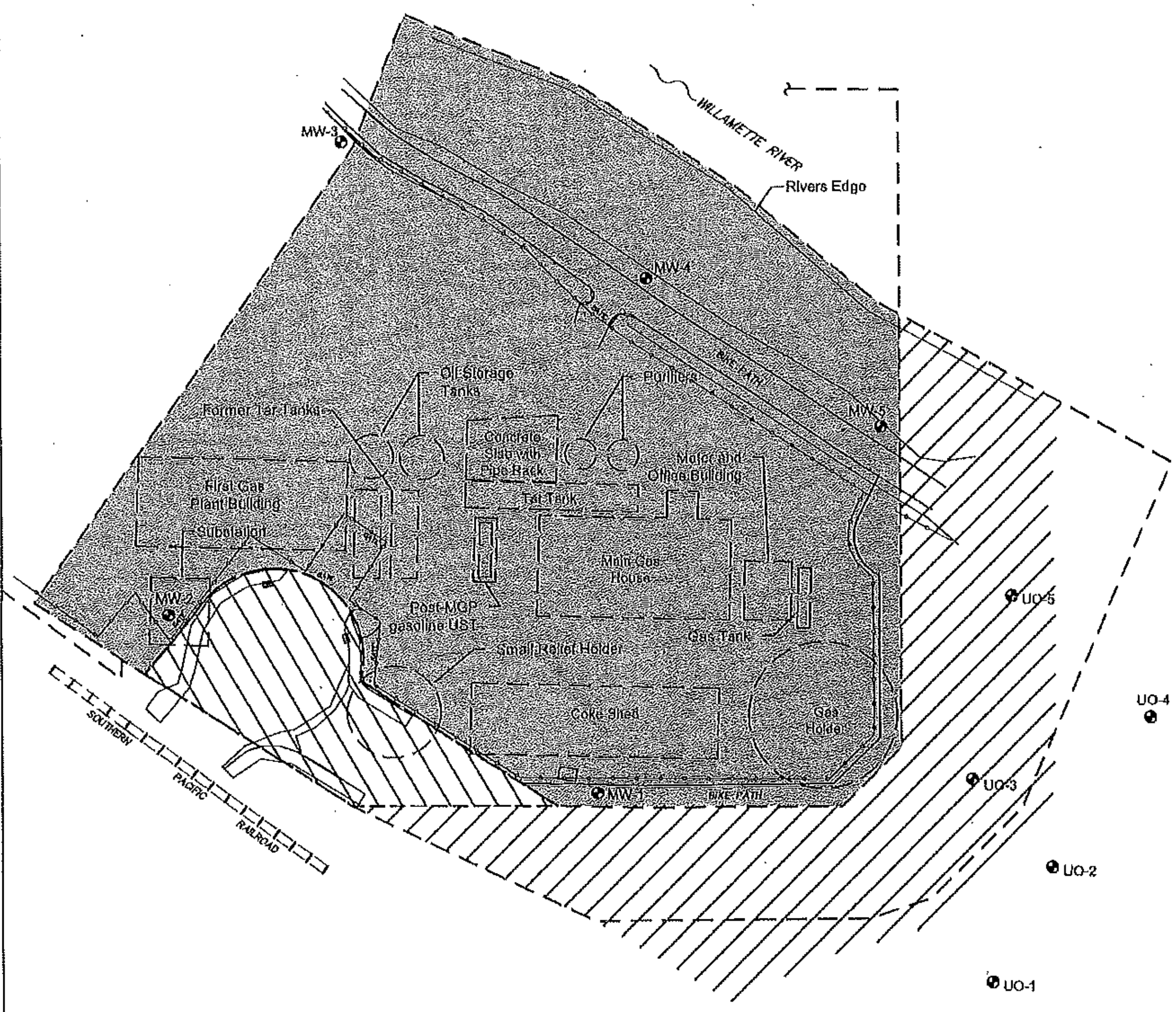


Figure 1. Site Location Map



⊕	Monitoring well
— — —	EWEB property line
—· —	Approximate location of revised locality of facility (LOF)
—o—o—	Fence line
⊐⊏⊐⊏	Railroad
(shaded)	Management Area (EWEB property subject to engineering and institutional controls)
(hatched)	University of Oregon Property
(dashed hatch)	City of Eugene Property

0 75
Feet
N

Notes:
1. Property boundary between City of Eugene and University of Oregon approximately located.

Sources:
1. Base Map Survey by: W&H Pacific (9/17/96)
2. Base Map Provided by: Swanson Hydrology + GeoMorphology and Windward Environmental, LLC. (Final Feasibility Study, April 2006)

Prepared by Integral Consulting Inc.

W:\Projects\Axelrod LLC EWEB MGP Site\Data\CAD_etc_from_Russ\Locality\From Integral\Figure_4_MGP_site_WW.dwg 1/27/2014 2:18:03 PM

WindWard environmental LLC   Axelrod

Figure 2
Site plan with main features, property boundaries, and Locality of Facility (LOF).

Appendix A

ADMINISTRATIVE RECORD AND SUPPORT DOCUMENTATION FOR RI/FS

Eugene Former Manufactured Gas Plant Site

Through December 2013

Administrative Record

Axelrod and Windward. 2007. Scoping approach for Level II (Screening) ecological risk assessment, Eugene Former MGP Site, prepared for Eugene Water & Electric Board by Axelrod LLC and Windward Environmental LLC, September 11, 2007.

Axelrod. 2008. Opportunistic shoreline probing during September 19 ecological habitat survey, Memorandum, Eugene Former MGP Site, prepared for Eugene Water & Electric Board by Axelrod LLC, February 13, 2008.

Axelrod and Windward. 2008. Focused work plan/sampling and analysis plan, Willamette River surface water sampling event, Eugene Former MGP Site, prepared for Eugene Water & Electric Board by Axelrod LLC and Windward Environmental LLC, December 3, 2008.

Axelrod and Windward. 2010a. Focused Soil/Fill Management Plan, Electric Transmission Line Construction Project – Eugene Former MGP Site, prepared for Eugene Water & Electric Board, August 31, 2010 (Draft).

Axelrod and Windward. 2010b. Removal Action at Gas Holder Foundation, Eugene Former MGP Site, Technical Memorandum, DEQ Review Draft, December 8, 2010.

Axelrod and Windward. 2011. Field Activity Summary - Focused Soil/Fill Management Plan, Eugene Former MGP Site, prepared for Eugene Water & Electric Board, April 2011.

Axelrod, Otak, and Windward. 2011. Focused feasibility study addendum – Eugene Former MGP Site, prepared for Eugene Water & Electric Board, by Axelrod LLC with support from Otak Inc. and Windward Environmental LLC, July 2011.

Axelrod. 2011. Letter from Russ Axelrod/Axelrod LLC to Geoff Brown/DEQ regarding EWEB Second Source Water Supply Evaluation – Supplemental Information for Administrative Record for MGP Site, June 11, 2012.

DEQ. 1995. Letter dated July 27, 1995, from Keith Andersen, DEQ to D. Unfried, EWEB, regarding addition of MGP site to the Environmental Cleanup Site Information System (#1723) and recommendation for inclusion on the Confirmed Release List. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1996a. File Review Summary, Eugene Former Manufactured Gas Plant Site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1996b. Letter dated November 20, 1996, from M. Wahl, DEQ, to D. Unfried, EWEB, regarding notice to owners and operators of decision to list contaminated property, Eugene former MGP. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1998a. Memorandum dated March 31, 1998, from B. Mason, DEQ, to D. Unfried, EWEB, approving field sampling plan for focused groundwater investigation with limited comments, Eugene former manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1998b. Intergovernmental Agreement for Remedial Investigation/Feasibility Study (DEQ No. WMCVC-WR-98-13) between EWEB and DEQ, November 25, 1998, including Attachment B (Voluntary Cleanup Program Remedial Investigation/Feasibility Study Scope of Work, September 23, 1998).

DEQ. 1999a. News Release dated January 7, 1999, DEQ and EWEB Sign Agreement for Cleanup, regarding intergovernmental agreement signed by DEQ and EWEB for Eugene former manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, Oregon.

DEQ. 1999b. Letter dated January 27, 1999, from M. McCann, DEQ, to D. Unfried, EWEB, regarding approval of project documents (ISI Work Plan [PTI 1995], ISI Report [PTI 1996], FGI FSP [Exponent 1998], FGI Results [Exponent 1998]), Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1999c. Letter dated January 27, 1999, from M. McCann, DEQ, to D. Unfried, EWEB, regarding approval of Phase I remedial investigation work plan with direction to address limited DEQ comments in later report or in future project meeting, Former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1999d. News Release dated October 22, 1999, Emergency Waste Removal Planned at Eugene Site, regarding planned removal of liquid waste from former tar containment tank. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1999e. Letter dated October 28, 1999, from M. McCann, DEQ, to D. Unfried, EWEB, regarding approval of plan for liquids removal from tar tank structure at former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1999f. Letter dated December 3, 1999, from M. McCann, DEQ, to D. Lawder, EWEB, regarding approval of Level 1 ecological risk assessment, former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 2001a. Letter dated January 4, 2001, from M. McCann, DEQ, to D. Lawder, EWEB, regarding approval of final Phase I Remedial Investigation completed at former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 2001b. Letter dated January 4, 2001, from M. McCann, DEQ, to D. Lawder, EWEB, regarding approval of final Land and Beneficial Water Use Survey completed at former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 2002. Letter dated December 20, 2002 from G. Brown, DEQ, to D. Lawder, EWEB, regarding approval of Human Health Risk Evaluation and Focused Feasibility Study – Annotated Outline, Eugene former manufactured gas plant site, Eugene, Oregon. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 2003. Letter dated November 26, 2003 from G. Brown, DEQ, to D. Lawder, EWEB, regarding focused feasibility study, Eugene former manufactured gas plant site, Eugene, Oregon. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 2006. Email dated April 5, 2006, from G. Brown, DEQ, to R. Axelrod, Swanson Hydrology & Geomorphology, regarding approval of final revisions to revised draft focused feasibility study, Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 2007. Letter dated October 22, 2007, from G. Brown, DEQ, to D. Spresser, EWEB, regarding Ecological Risk Assessment, Former Manufactured Gas Plant, ECSI #1723. Oregon Department of Environmental Quality, Western Region Cleanup Program, Eugene, OR.

DEQ. 2010a. DEQ letter from Geoff Brown/DEQ to Debbie Spresser/EWEB approving the *August 9, 2010 (Draft) Focused Soil/Fill Management Plan, Electric Transmission Line Construction Project, Eugene Former MGP Site,* letter dated August 11, 2010.

DEQ. 2010b. DEQ letter from Geoff Brown/DEQ to Debbie Spresser/EWEB regarding *MGP Waste discovered during the Electric Transmission Line Construction Project – Eugene, October 1, 2010, Eugene Former MGP Site, ECSI 1723,* letter dated October 1, 2010.

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MANAGEMENT APPROVAL FORM
Final Approval
Department of Environmental Quality
Western Region

REPORT/DOCUMENT TYPE:
(Attached)

Record of Decision ____X______

Certification of Completion ______

Other (Describe)______________

Date: 1/21/15

Please review the attached document which describes a staff recommendation regarding an environmental cleanup activity. The approved preliminary recommendation has been advertised for public comment as required by ORS 465.320. The public comment period has expired. The attached document includes a discussion of public comments received (if any) and how those comments affected the final recommendation/decision.

FINAL APPROVAL:

______________________________ Assistant Attorney General (DOJ) ______________ Date

Michael E Kortenhof ______________ Section Manager 1/21/2015 Date

______________________________ Regional Administrator ______________ Date

______________________________ Other (Indicate) ______________ Date

Return completed form to: Seth Sadofsky
Western Region Environmental Cleanup

RECORD OF DECISION

FOR

EUGENE MANUFACTURED GAS PLANT (FORMER)

CUL-DE-SAC PORTION

700 block of E 8th Avenue

T17S, R3W, Section 32, City Right-of-Way Adjacent to Tax Lot 1500, Lane County

EUGENE, OREGON

ECSI 1723

Date: January 21, 2015

Introduction

Soil and/or groundwater contamination associated with operation of the Former Manufactured Gas Plant (MGP) is present on property owned by EWEB, property owned by the University of Oregon, and the cul-de-sac property located southwest of the EWEB property (Figure 1 and 2). Most of the contamination is located in the vicinity of the historical MGP, which was located on the central portion of the site, within the existing EWEB fence line. The site is located on the south bank of the Willamette River, in a mixed use area neighborhood encompassing commercial, industrial, office, residential, and park land uses. This Record of Decision (ROD) is specific to the cul-de-sac portion of the site (Site). The cul-de-sac is a City of Eugene public right-of-way. The cul-de-sac portion consists of approximately 0.3-acres and consists of the extension of East 8th Avenue northeast of the railroad tracks that dead-ends in a cul-de-sac. This ROD prescribes the remedial action for the Site, which is necessary to meet the Site remedial action objectives and protect human health and the environment. The adjacent portions of the former MGP site on EWEB property and on University of Oregon property are being addressed in other documents.

Additional information on this Site, including the full Staff Report to which this document refers, can be found at the following web site.

http://www.deq.state.or.us/Webdocs/Forms/Output/FPController.ashx?SourceId=1723&SourceI dType=11

Public Process

A 30-day public comment period on DEQ's recommended remedy was held during September of 2014, as required by ORS 465.320. Notice was published as a legal ad in the Eugene Register-Guard, in the Secretary of State Bulletin, and on DEQ's web site. A link to this notice on DEQ's web site was published through DEQ's GovDelivery service to all who have registered interest in receiving Environmental Cleanup notices. A newspaper article about the MGP site and proposed cleanup was published in the Eugene Register-Guard early in the public comment period, and an additional article on a related subject mentioned the public comment period. No comments were received during this period.

Summary of Site Investigation Activities

Investigations at the MGP site have been conducted by environmental consultants working for EWEB, PacifiCorp, and Cascade Natural Gas Corporation. The initial investigation of the MGP site took place in 1995, which was followed by groundwater investigations through 1998 and a Remedial Investigation Report submitted to DEQ in 2000. A Human Health Risk Evaluation was submitted to DEQ in 2002 with a supplemental Technical Memo in 2003; and Ecological risk was assessed by a Level I Ecological Risk Assessment in 1999 and a Level II Ecological Risk Assessment in 2009. A Draft Feasibility Study proposing remedial action alternatives was submitted to DEQ in 2003; and a revised Feasibility Study was submitted in 2006 incorporating comments by DEQ. A technical memorandum prepared in 2011 by AECOM highlights the specific RI/FS issues associated with the cul-de-sac portion of the MGP site.

Remedial Action Objectives

Based on the results of the Remedial Investigation and Risk Assessment, Remedial Action Objectives (RAOs) were developed by DEQ and the responsible parties to address the presence of polynuclear aromatic hydrocarbons (PAHs) and benzene in contaminated soil. These RAOs are:

- Prevent industrial and excavation worker exposure to soils containing contaminants of concern (COCs) above the soil numerical remedial action objectives (NRAOs).
- Prevent exposure to future Site visitors/workers from vapor intrusion of benzene into indoor spaces above the numerical NRAOs.
- Minimize or control infiltration of rainwater through contaminated soil to prevent mobilization of contaminants to the Willamette River.
- Treat (or excavate and dispose offsite) soil/waste material identified as hot spots (i.e., from the small relief holder), to the extent feasible considering the criterion in OAR 340-122-0085(7) and the balancing factors in OAR 340-122-0090(3).

The remedial actions for soil will be guided by NRAOs based on risk-based screening levels rather than Site-specific cleanup levels. Remedial actions based on these NRAOs are protective for the potential exposure pathways listed. Should alternative or contingent remedial actions be considered in the future, Site-specific cleanup levels may be developed in cooperation with DEQ and applied in lieu of the NRAOs. The following numerical remedial action objectives were developed to protect industrial Site workers and excavation workers. Remedial action objectives for carcinogenic chemicals are based on a 1×10^{-6} cancer risk, while non-carcinogenic chemicals are based on a Hazard Index (HI) of 1. Soils that contain chemicals in excess of remedial action objectives will require action to prevent unacceptable human exposure.

NUMERICAL SOIL REMEDIAL ACTION OBJECTIVES
Eugene Former Manufactured Gas Plant Site

HAZARDOUS SUBSTANCE	INDUSTRIAL CONCENTRATION	DEQ EXCAVATION WORKER CONCENTRATION	BASIS AND PRIMARY EXPOSURE PATHWAY
Cyanide	610	5,100	HI=1 Direct contact
2-Methylnaphthalene	23*	16,000*>Csat	HI=1 Direct contact

NUMERICAL SOIL REMEDIAL ACTION OBJECTIVES
Eugene Former Manufactured Gas Plant Site

HAZARDOUS SUBSTANCE	INDUSTRIAL CONCENTRATION	DEQ EXCAVATION WORKER CONCENTRATION	BASIS AND PRIMARY EXPOSURE PATHWAY
Acenaphthylene	23*	16,000*>Csat	HI=1 Direct contact
Benz[a]anthracene	2.7	590>Csat	1x10^{-6} Risk, Direct Contact
Benzo[a]pyrene	0.27	59>Csat	1x10^{-6} Risk, Direct Contact
Benzo[b]fluoranthene	2.7	590>Csat	1x10^{-6} Risk, Direct Contact
Benzo[g,h,i]perylene	23*	16,000*>Csat	HI=1 Direct contact
Benzo[k]fluoranthene	27	5,900>Csat	1x10^{-6} Risk, Direct Contact
Chrysene	270	59,000>Csat	1x10^{-6} Risk, Direct Contact
Indeno[1,2,3-cd]pyrene	2.7	590>Csat	1x10^{-6} Risk, Direct Contact
Naphthalene	23	16,000>Csat	HI=1 Direct contact
Phenanthrene	23*	16,000*>Csat	HI=1Direct contact
Benzene	34	9,500>Csat	1x10^{-6} Risk, Direct Contact

NOTES:
The numerical remedial action objective values for soil are risk-based concentrations (RBCs) from DEQ's 2003 RBDM, as updated 2012. Cyanide numerical remedial action objective is from USEPA's Region Screening Level (RSL) Summary Table, May 2011. Direct contact includes soil ingestion, dermal contact, and inhalation.
1) Soil units shown are in mg/kg, or ppm.2) Cumulative excess cancer risk for all carcinogens shall not exceed 1x10^{-5}
3) The soil numerical remedial action objective for benzene in indoor air (vapor intrusion into buildings) is 1.2 mg/kg (DEQ 2003 RBDM, as updated 2012).
* Surrogate value based on toxicity data for naphthalene.

Evaluation of Remedial Alternatives

Four potential remedies were evaluated in the Staff Report for the Site, they are:

1. No Action
2. Engineering and Institutional Controls
3. High Concentration Residuals/Waste Removal at Small Relief Holder and Engineering and Institutional Controls
4. Deep Soil Removal, and Engineering and Institutional Controls

These potential remedies were evaluated on the basis of protectiveness, long-term reliability, implementability, implementation risk, and reasonableness of cost, as well as the degree to which they address identified hot spots according to OAR 340-122-090.

Description of Selected Remedy

DEQ has selected the remedial action recommended in its Staff Report as the final remedy for the Site in accordance with Oregon Revised Statutes (ORS) 465.200 et. seq. and Oregon Administrative Rules (OAR) Chapter 340, Division 122, Sections 010 through 115. The recommended remedial action includes several measures to meet the above RAOs, including:

- Excavation and off-site disposal of high-concentration residuals/waste at the small relief holder (which will be completed as in conjunction with the remedial action for the portion of the MGP site owned by EWEB);
- Engineering controls consisting of a cap to the areas of the cul-de-sac not already paved;
- Institutional controls consisting of an Easement & Equitable Servitude restricting property use, and development of a site management plan (SMP);
- Inspection and maintenance of the Site conditions and features according to the SMP.

The selected remedy is described in more detail below.

Excavation and off-site disposal of high-concentration residuals/waste

High-concentration residuals/waste will be removed at the small relief holder foundation by excavation. This excavation will be completed as part of the remedial action on the adjacent portion of the MGP site owned by EWEB. This material will be disposed of properly after characterization.

Engineering Controls

Engineering controls will consist of capping the small area of the cul-de-sac that is not already paved.

Institutional Controls – Easement and Equitable Servitude

A DEQ-approved Easement and Equitable Servitude (E&ES) will be recorded in the county property records with the following general requirements for the Management Area:

1. Groundwater Use Restrictions: No one may extract through wells or by other means or use the groundwater at the Site for consumption or other beneficial use. This prohibition does not apply to extraction of groundwater associated with groundwater treatment or monitoring activities approved by DEQ or to temporary dewatering activities related to construction, development, or the installation of sewer or utilities at the Site. Any generator of waste water must conduct a waste determination on any groundwater that is extracted during such monitoring, treatment, or dewatering activities and handle, store and manage waste water according to applicable laws.

2. Soil Cap Engineering Control. Except in accordance with a SMP approved in writing by DEQ, no one may conduct or allow operations or conditions on the Site or use of the Site in any way that will or likely will penetrate the cap at the Site or jeopardize the cap's protective function as an engineering control that prevents exposure to contaminated soil, including without limitation any excavation, drilling, scraping, or uncontrolled erosion. The Site owner will maintain the cap, if applicable, in accordance with an SMP approved in writing by DEQ.

3. No buildings for human occupancy shall be constructed at the Site (e.g., offices, shops, retail development, or residential development) unless additional Site-specific analyses are conducted to demonstrate that RAOs will be met, which analyses must be approved by DEQ, and unless aspects of the building construction to meet RAOs, if any, are approved by DEQ.

Institutional Controls – Site Management Plan

A DEQ-approved SMP will be prepared for the Site, which will cover the following general topics:

1. Excavation worker health and safety. The SMP will describe how work shall be conducted at the Site, who can complete the work, what notifications will need to occur prior to work commencing, measures for personal protective equipment and training required to work on the Site, and general protocols for excavating, storing, characterizing, and disposing of any excavated materials from the Site.

2. Cap Maintenance. The SMP will detail how and at what interval the cap will be inspected and outline any regularly scheduled cap maintenance that may be required. The SMP will also include responsibility for this task and an appropriate reporting schedule.

Residual Risk

Under the recommended remedial action alternative, Site risks will meet the protectiveness standard required by OAR 340-122-0040 by applying the following measures.

- **Excavation and Construction Worker Scenario.** Risk from this exposure type is reduced to acceptable levels through a SMP that will be prepared to direct all future excavation activities.
- **Occupational Worker Scenario.** To address this risk, an asphalt cap will be placed over the Site, and cap inspections and maintenance will be included in the SMP.
- **Potential Future Exposure to Vapor Intrusion to Buildings.** No buildings currently exist at the Site. However, to address the potential for future unacceptable risk regarding commercial building structures, an institutional control will be included in the property Easement and Equitable Servitude. Specifically, no buildings for continuous human occupancy will be allowed on the Site unless additional site-specific analyses are conducted in the future to demonstrate that RAOs would be met and the analyses are coordinated with DEQ, and aspects of the building construction to meet RAOs are approved by DEQ.

Statutory Determination

The selected remedial action for MGP-related contamination at the cul-de-sac portion of the former Eugene Manufactured Gas Plant is considered to be protective, effective, reliable, and cost-effective. The selected remedy also treats or removes the identified hot spots of contamination to the extent feasible in accordance with OAR 340-122-090. The selected remedy is consistent with the current and future anticipated use of the Site and is protective of current and future anticipated beneficial water use within the Site Locality of the Facility (LOF). Residual risks associated with the selected remedy are below DEQ's acceptable risk levels.

Attached
Figure 1
Figure 2

Administrative Record

Administrative Record

AECOM. Memorandum on Subsurface Conditions at Intersection of Hilyard Street and East 8th Avenue. September 30, 2011.

Axelrod and Windward. 2010a. Focused Soil/Fill Management Plan, Electric Transmission Line Construction Project – Eugene Former MGP Site, prepared for Eugene Water & Electric Board, August 31, 2010 (Draft).

Axelrod and Windward. 2010b. Removal Action at Gas Holder Foundation, Eugene Former MGP Site, Technical Memorandum, DEQ Review Draft, December 8, 2010.

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DEQ. 1999c. Letter dated January 27, 1999, from M. McCann, DEQ, to D. Unfried, EWEB, regarding approval of Phase 1 remedial investigation work plan with direction to address limited DEQ comments in later report or in future project meeting, Former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 1999f. Letter dated December 3, 1999, from M. McCann, DEQ, to D. Lawder, EWEB, regarding approval of Level 1 ecological risk assessment, former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

DEQ. 2001a. Letter dated January 4, 2001, from M. McCann, DEQ, to D. Lawder, EWEB, regarding approval of final Phase I Remedial Investigation completed at former Eugene manufactured gas plant site. DEQ, Western Region Cleanup Program, Eugene, OR.

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DEQ. 2002. Letter dated December 20, 2002 from G. Brown, DEQ, to D. Lawder, EWEB, regarding approval of Human Health Risk Evaluation and Focused Feasibility Study – Annotated Outline, Eugene former manufactured gas plant site, Eugene, Oregon. DEQ, Western Region Cleanup Program, Eugene, OR.

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Exponent. 1999c. Level I (Scoping) Ecological Risk Assessment report, prepared for Eugene Water & Electric Board by Exponent Inc., Lake Oswego, Oregon, January 1999.

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Exponent. 2000b. Phase I remedial investigation report, former manufactured gas plant site, Eugene, Oregon, December 2000. Prepared for Eugene Water & Electric Board, Eugene, Oregon. Exponent, Lake Oswego, OR.

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PTI. 1996. Initial site investigation report, former manufactured gas plant site, Eugene, Oregon. Prepared for Eugene Water & Electric Board, Eugene, Oregon. PTI Environmental Services, Lake Oswego, OR.

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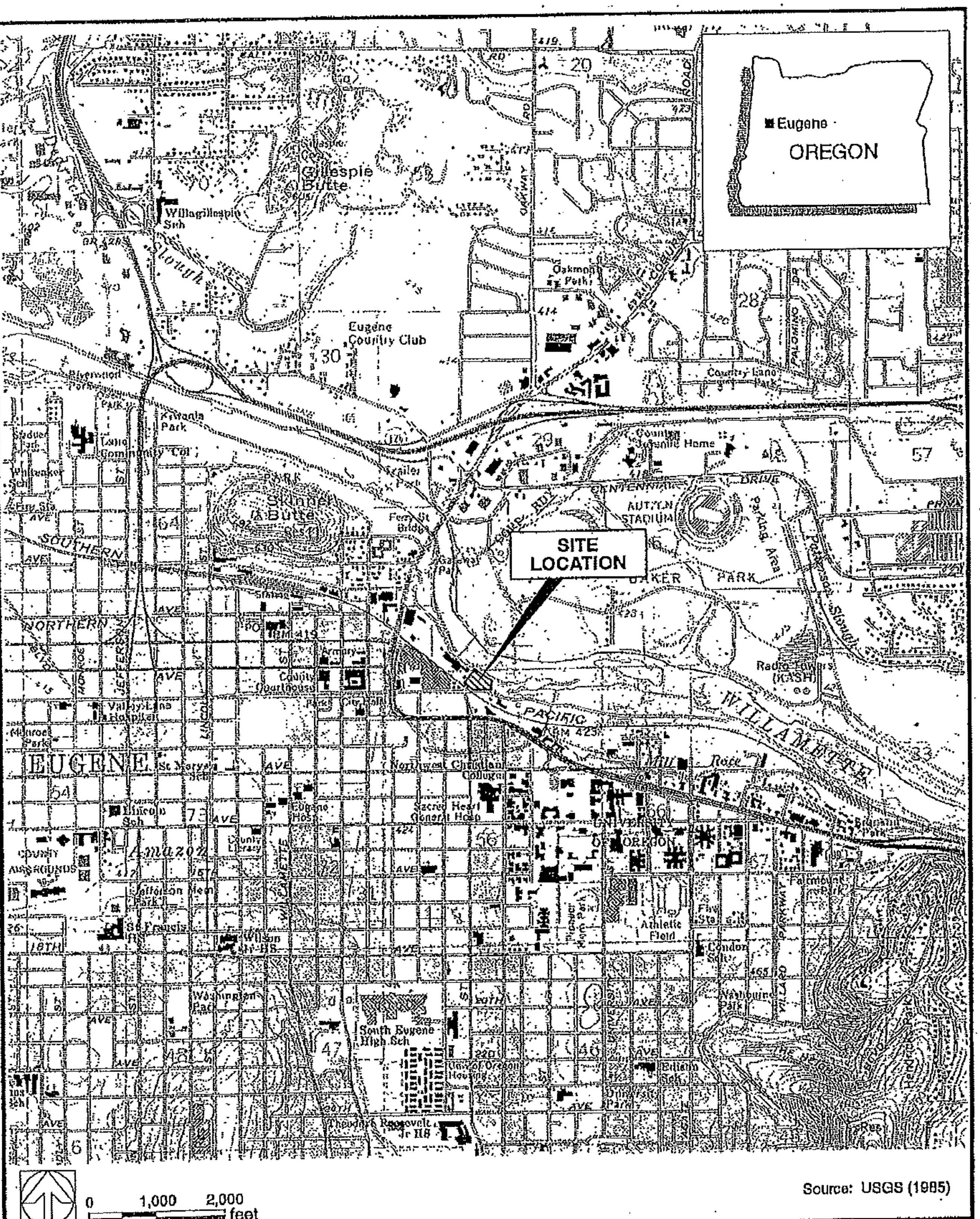
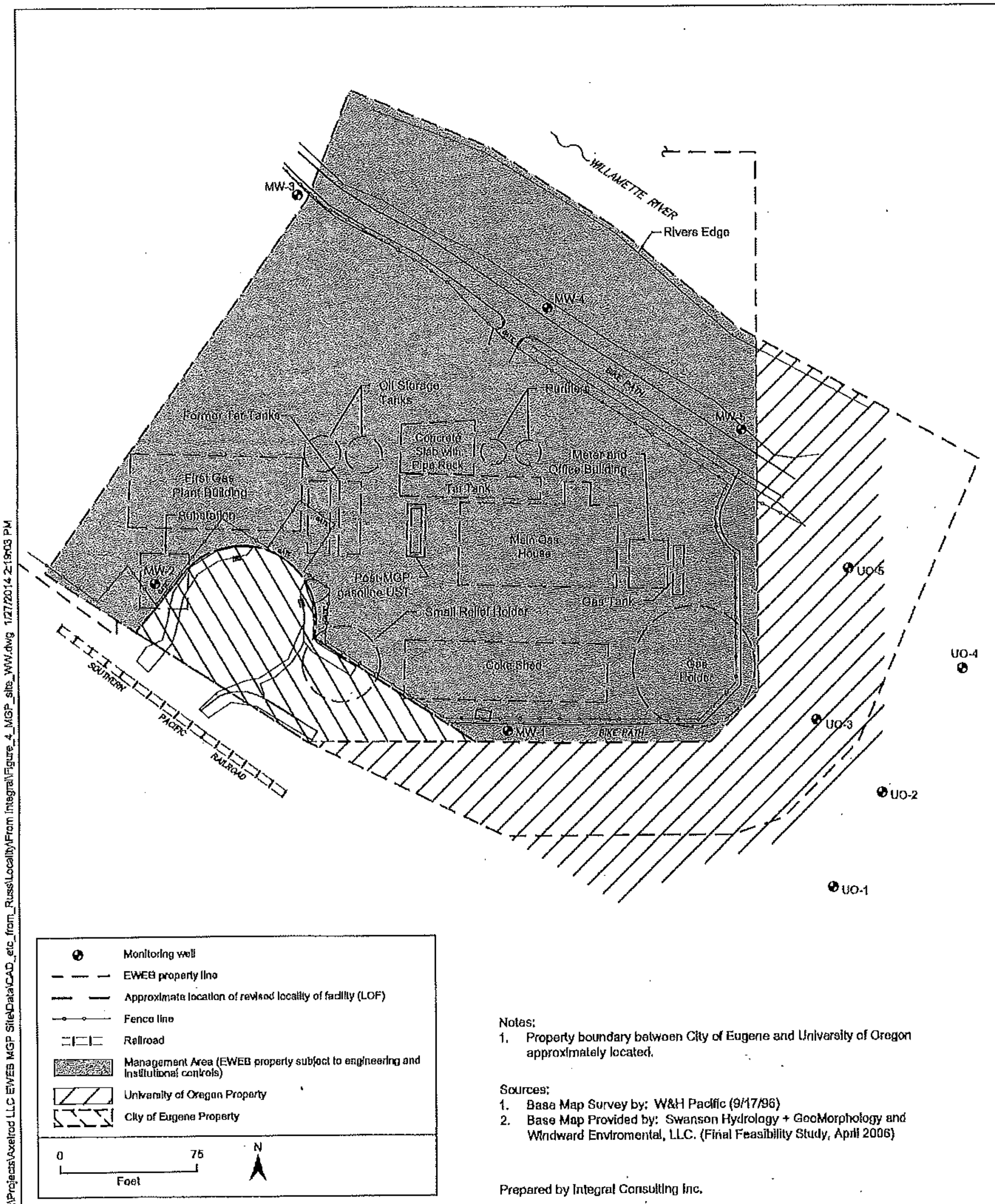


Figure 1. Site Location Map



Notes:
1. Property boundary between City of Eugene and University of Oregon approximately located.

Sources:
1. Base Map Survey by: W&H Pacific (9/17/96)
2. Base Map Provided by: Swanson Hydrology + GeoMorphology and Windward Enviromental, LLC. (Final Feasibility Study, April 2006)

Prepared by Integral Consulting Inc.

WindWard environmental LLC Axelrod

Figure 2
Site plan with main features, property boundaries, and Locality of Facility (LOF).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Confidential Exhibit No. 310
(PROVIDED ON CD)

Calculation of Environmental Remediation Proposal

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

MICHAEL P. PARVINEN
Exhibit No. 311

Pipeline Recovery Mechanism Sample Calculation

Cascade Natural Gas
Pipeline Recovery Mechanism Sample Calculation

Replacement Projects 1-1-16 to 8-31-16

	Project		Estimtimated Cost	30-Jun-16 Actual Cost						
1	x1		$1,000,000	$1,000,000						
2	x2		$500,000	$0						
3	x3		$2,000,000	$1,000,000						
4	x4		$500,000	$500,000						
5	x5		$0							
6	x6		$0							
7	x7		$0							
8	Total Estimated Replacement Cost		$4,000,000	$2,500,000						
				Schedule 101	**Schedule 104**	**Schedule 105**	**Schedule 111**	**Schedule 170**	**Schedule 163**	**Schedule 900**
9	Main Incremental Investment Allocation from UG-287 Company COS		$369,272,368	$180,950,490	$112,346,225	$14,286,870	$6,435,931	$4,211,274	$40,766,123	$10,275,455
10	Percentage		100.00%	49.00%	30.42%	3.87%	1.74%	1.14%	11.04%	2.78%
11	Total Investment	Ln 8	4,000,000							
12	Depreciation Expense - Rate 2.96%	Ln 11* 2.96%	118,400	118,400						
13	Accumulated Depr. (Avg)	Ln 12 / 2	59,200							
14	Tax depreciation - Rate 5.00%	Ln 11 *5%	200,000							
15	Deferred Tax	(Ln 14 - Ln 12) * .3994	32,591							
16	Accum Def Tax (Avg)	Ln 15 / 2	16,296							
17	Income Tax	Ln 12 * .3994		47,289						
18	Rate Bate		3,924,504							
19	Authorized ROR from UG-287		7.47%							
20	NOI	(Ln 18 * Ln 19) + (Ln 12 - Ln 17)	$293,160	$71,111						
21	Total NOI	(Ln 18 * Ln 19) + (Ln 12 - Ln 17)		$364,272						
22	Conversion Factor from Company Testimony in UG-287			0.58346						
23	Revenue Requirement	Ln 21 / Ln 22		$\boxed{\textbf{\$624,330}}$						
24	Allocation Rev Req to Schedules	Ln 23 * Ln 19		$305,934	$189,944	$24,155	$10,881	$7,120	$68,923	$17,373
25	Weather Normalized 2016 Volumes (Same as PGA)			3,944,203	2,790,590	253,388	157,985	276,803	3,478,380	22,844,121
26	Rate Change	Ln 24 / Ln 25		$0.07757	$0.06807	$0.09533	$0.06888	$0.02572	$0.01981	$0.00076
27	2015 Spring Earnigs Review Total Revenue			$73,859,618						
28	Percentage Increase in Revenue	Ln 23 / Ln 27		0.85%						

CNG/400
Robinson

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

DIRECT TESTIMONY OF MICAH ROBINSON
REPRESENTING CASCADE NATURAL GAS CORPORATION

Forecast Methodology

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Micah Robinson and my business address is 3800 Buffalo Speedway, Suite 200, Houston, TX 77098.

Q. By whom are you employed and in what capacity?

A. I am employed by MRE Consulting, and my present position is Gas Supply and Regulatory Consultant.

Q. What is your present association with Cascade Natural Gas Corporation?

A. I have been retained by Cascade Natural Gas Corporation (Cascade or the Company) to manage and deliver the long term forecast methodology and model for use in the 2014 Integrated Resource Plan (IRP).

Q. Would you briefly describe your duties?

A. My primary areas of responsibility include the definition, documentation, and implementation of Cascade's long term forecast related to the 2014 IRP.

Q. Please briefly describe your educational background and professional experiences.

A. In 2000, I graduated from Texas A&M University with a Bachelor of Science in Industrial Distribution. I started working with Accenture (Anderson Consulting) in May 2001 as an analyst in Accenture's business consulting organization located in Houston, Texas, with a primary focus on the energy industry. In 2006, I joined MRE Consulting, where I am now a Director focused on the implementation of business process design and modeling, system implementations, and custom development efforts.

During the course of my 14-year career, I have been responsible for and involved with business processes and systems required for load forecasting, electric and gas rate design, trading and risk management, and many other energy industry responsibilities.

II. DEMAND FORECAST MODEL

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

A. The scope of my testimony in this proceeding will cover the long term demand forecast model Cascade will be using to predict monthly demand, monthly usage, and annual customer counts by tariff schedule at the CityGate level. The results of the long term forecast model were used as a guide to spread the proposed expected demand, monthly usage, and annual customer counts presented as part of the 2014 IRP.

Q. Are you providing any exhibits in support of your testimony?

A. Yes, I have provided Exhibit CNG/401 which contains Cascade's Twenty-Year Demand Study for Oregon. The results of this study were also provided to other Cascade witnesses in this proceeding.

Q. What is demand as used in your testimony?

A. Demand refers to Cascade's historical or future monthly gas usage by CityGate. A CityGate is the point where natural gas deliveries transfer from the interstate pipeline to Cascade's distribution system.

Q. What is the difference between core and non-core demand?

A. Cascade core demand is comprised of residential, commercial, and industrial customers' usage assigned to bundled gas services as defined by tariff. Cascade non-core demand is comprised of commercial and industrial customers' usage assigned to unbundled gas services as defined by tariff.

Q. What is a forecast model?

A. A forecast model is a statistically driven tool that uses historical information to best predict future natural gas usage and the number of customers at a CityGate level.

Q. Why does Cascade use a demand forecast model?

A. Cascade uses a demand forecast model to generate statistically driven results which project an estimate of gas demand sales and peak demand over a 20-year planning period. Forecasted demand is used in long term planning for resources and delivery systems. The 20-year horizon helps Cascade anticipate resource needs and develop timely responses.

Q. Would you please describe the Cascade demand forecast model?

A. The Cascade demand forecast model is a statistical tool which takes calculated heating degree days (HDDs) derived from historical weather and historical demand to generate a linear regression which is used to project weather-dependent demand. Non-weather-dependent demand is then added to weather-dependent demand to produce a consolidated demand figure. Finally, annual growth is applied to generate a predicted demand value by CityGate.

Q. How are the HDD values used in the forecast model calculated?

A. HDD values are calculated by beginning with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from a HDD degree threshold (for example 65°F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs can never be negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to notably rise. The historical threshold for calculating HDDs has been 65 °F. However, when modeling gas demand based on weather, Cascade has determined that lowering the threshold to 60 °F produces better results. Cascade determined that heating demand does not begin to increase significantly until a HDD of five (65 °F minus 60 °F) if the traditional HDD threshold of 65 °F is utilized.

Lowering the HDD threshold thus gives a better measure of the relation between HDD and therms (measurement of heat usage).

Q. What was the source of historical weather data used in the forecast model?

A. The source of historical weather data for all weather related analysis is the Schneider Electric weather service. Weather values used in weather related analysis include the minimum (Min) and maximum (Max) temperatures per weather station and day. Schneider Electric weather values were derived from National Oceanic and Atmospheric Administration (NOAA) actual weather values for a weather station and day. If NOAA weather was not available for a weather station and day, a Schneider weather estimate is used.

Q. How many weather station locations are used in the forecast model?

A. There are seven weather station locations: Bellingham, Bremerton, Walla Walla, and Yakima for Washington; and Baker City, Pendleton, and Redmond for Oregon.

Q. What was the source of the historical demand data used in the forecast model?

A. Historical core monthly demand by CityGate was derived from three sources:

- The Company's Customer Care and Billing system (CC&B) provided billing demand by town, tariff, year, and month;
- The Company's Gas Management System (GMS) provided non-core demand by CityGate, year, and month;
- Pipeline Electronic Bulletin Board (EBB) systems provided demand flow data by CityGate, year, and month.

Q. How was core and non-core demand calculated from historical data?

A. Cascade calculates core demand by using pipeline flow data for each CityGate, which represents total gas flow for both core and non-core customers, and subtracting Cascade's non-core data by CityGate. Non-core data comes from

Cascade's own Gas Management System (GMS) which tracks non-core data demand by individual customers behind each CityGate.

Core demand is improved further by a Cascade analyst who removes data that is clearly non-weather related and is atypical of Cascade's core deliveries. A review of CC&B customer ("premise") counts and demand by tariff assists in identifying this data. The removed data is later reinserted into the forecast but only after weather regressions are performed. Removing the data prior to performing the regressions improves the quality of the weather modeling.

Q. What data is used to determine annual growth?

A. Growth is a calculated value which is determined based upon Woods & Poole growth projection data, economic, mixed, or a manually assigned Cascade growth adjustment plus a derived U.S. Energy Information Administration (EIA) efficiency factor. Woods & Poole Economics, Inc. is an independent firm that specializes in long-term county economic and demographic projections. Woods & Poole's database for every county in the U.S. contains projections through 2040 for more than 900 variables. Each year, Woods & Poole updates the projections with new historical data. Woods & Poole has been making county-level growth projections since 1983, and public utilities, state and local government, consultants, retailers, market research firms and planners rely on the Woods & Poole growth projection data.

Cascade utilizes a manual growth adjustment when it determines the Woods & Poole growth figure does not best project the growth of a CityGate for a period of time. Manually assigned growth factors are based on supporting analytics related to premises growth, engineering estimates, and internal customer projections. Growth effects are cumulative, which means that growth effects from one year carry over into the next year. However, there can occasionally be predictable events that impact demand for a specific time period but in a manner such that normal demand resumes when the event is over. For example, a factory may shut down for several months but return to full gas usage after the shutdown. This in turn would reduce CityGate demand for those months but would not affect demand thereafter. Cascade incorporates these non-cumulative events in its forecast as a manual assumption.

Q. How is growth applied in the forecast model?

A. Growth is a calculated value which is determined based upon Woods & Poole growth, economic, mixed, or a manually assigned Cascade growth adjustment plus an EIA efficiency factor. Cascade utilizes a manual growth adjustment when it determines the Woods & Poole growth figure does not best project the growth of a CityGate for a period of time.

Q. What historical customer data is used in the forecast model?

A. Historical customer count data was gathered through the analysis of monthly premise counts. The historical premise count by year and CityGate was derived from the analysis of monthly premise counts by town and tariff pulled from the Customer CC&B system. Monthly premise counts by town, tariff, and year were allocated by town to each CityGate to determine total allocated CityGate premise count by tariff, year, and month.

Q. What types of scenarios are modeled in the forecast model?

A. A combination of high, medium, or low weather scenarios with high, medium, or low growth are modeled in the forecast model. A high weather scenario consists of cold weather that results in high demand. A low weather scenario consists of warm weather that results in low demand. The medium weather with medium growth is the base case that is used in the final forecast.

Q. How are weather scenarios modeled in the forecast model?

A. To determine the average (medium) weather case scenario, the average HDD of each month was taken from a specified range of years for each of the seven weather locations. The forecast used a 30 year range of weather history from the years 1984 through 2013 for each of the three scenarios.

To determine the high case HDD weather scenario, Cascade selected the years representing the six coldest years (20% of the coldest years out of 30). These are the particular years with the highest system wide HDD. To determine the low case HDD weather scenario, Cascade selected the years representing the six warmest years (20% of the warmest years out of 30). These are the particular years with the lowest system wide HDD. For both the high and low case HDD weather scenarios, for each particular month of a given projected future year, the HDD from these six years average to provide the appropriate scenario.

Q. How are growth scenarios modeled in the forecast model?

A. Cascade has defined three growth scenarios to adjust expected demand.

- Expected growth: utilized the annual growth factor
- High growth: utilized the annual growth factor plus an assigned high growth factor adjustment
- Low growth: utilized the annual growth factor minus an assigned low growth factor adjustment

Q. What type of regression does the forecast model use to predict future usage?

A. To forecast weather-dependent load, which accounts for weather differences, Cascade conducted a linear regression analysis[1] to develop a regression coefficient and constant for each CityGate. Cascade preformed a regression analysis of

[1] Regression analysis is a statistical process used to study the relationship between variables – in this case weather and demand.

weather-dependent monthly gas demand in comparison with monthly HDDs at each CityGate for historical demand. The regression analysis calculated the coefficient ***b*** and constant ***C*** that best minimizes the error.

Q. How was peak day determined?

A. Cascade determines the peak demand day for the entire system by first selecting the coldest day recorded in the past 30 years. To determine the system wide peak demand day, HDDs from all seven weather stations are considered, giving appropriate weight to the weather stations having the greater impact on system wide demand. The calculation of the system-weighted HDD is applied to the previous 30 years of weather data to determine the highest HDD. Cascade found December 21, 1990 to be the highest system-weighted HDD for this period.

Q. How is expected peak day demand calculated?

A. Expected peak day demand in a given year, in contrast with the highest case scenario peak day demand, is calculated by Cascade based on the average of the peak demand days for each of the last 30 years. Initially, the system-weighted peak day is found for each of the last thirty years. The actual HDD from each of those 30 peak days is averaged for each weather station resulting in an average peak HDD. Applying the associated average peak HDD to the forecast model for each CityGate yields an expected peak demand for each CityGate. Cascade calculates the expected peak demand for each CityGate for each future year of the forecast by then applying appropriate growth factors.

Q. Please provide an overview of the operation of the forecast model to develop an expected final forecast.

A. For each CityGate, historical demand and historical weather are used to find a least squares linear regression. The medium weather scenario HDD is applied to the linear regression to give a predicted load usage at a monthly level. The medium growth figure is applied to the predicted load to give a final figure for each month for 20 years. The customer count by tariff schedule from the previous year is applied to a medium growth factor and this gives us the customer count forecast.

Q. Have you prepared any supporting documentation that summarizes Cascade's demand study results?

A. Yes. Exhibit CNG/402, Cascade's Twenty-Year Oregon Forecast by CityGate describes the demand study performed for Cascade.

Q. How is the load forecast broken out by customer class?

A. Historical CC&B data is used to determine a breakout of usage per customer class for each CityGate. The usage per customer class is applied to the total usage for the respective CityGate to give a monthly load by CityGate by tariff.

III. BILLING DETERMINANTS

Q. Have you prepared any supporting documentation that provides Cascade's pro forma volumes and billing determinants?

A. Yes. Exhibit CNG/403, 2015 Oregon Customer and Volume Forecast by Tariff, describes the IRP demand volumes and customer counts.

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

A. Yes.

CNG/401
Robinson

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

Micah Robinson
Exhibit No. 401

Twenty-Year Demand Study

CASCADE NATURAL GAS TWENTY YEAR DEMAND STUDY

2014 IRP Supporting Document

Abstract

This document contains the forecast methodology and supporting documentation for the 20 year demand forecast results generated as part of the combined demand study. Cascade engaged MRE Consulting and Gelber & Associates to generate the 2014 IRP filing.

MRE Consulting, Ltd
Gelber & Associates Corp

Table of Contents

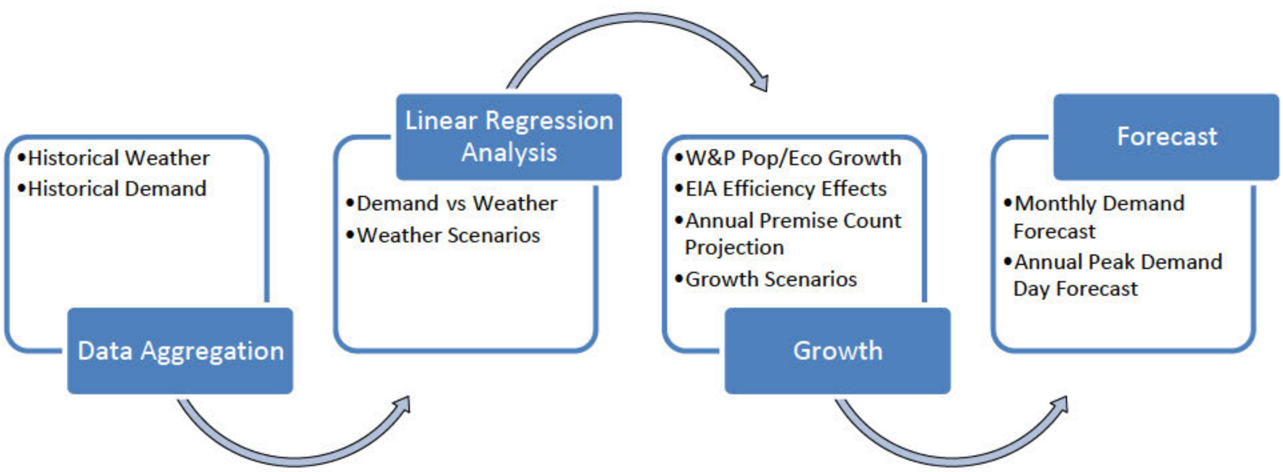
I. Methodology

a. Introduction

The Cascade demand forecast developed for the IRP is an estimate of gas demand sales and peak demand over a 20-year period for core customers at each CityGate[1] or Demand Loop[2]. Cascade core load consists mostly of residential and commercial customers along with some industrial customers. The forecasts developed in this study are designed for use in long-term planning for resources and delivery systems. The 20-year horizon helps Cascade anticipate needs and develop timely responses.

This document defines the assumptions and methods employed in generating the forecast as well and provides definition of terms where appropriate. The past 30 years of weather data and 10 years of demand data were analyzed to generate the forecast projection for the next 20 years.

Cascade has employed a methodology designed to identify and minimize uncertainties, and to increase the transparency and accuracy of the forecast. This forecast, along with the rest of the IRP, assists Cascade in providing the best service possible for the benefit of its customers.



[1] CityGate marks the point where the gas utility, Cascade, delivers gas from the gas pipeline company to a large group of customers. This report forecasts gas demand from Cascade's 76 CityGates.
[2] Demand loop is a grouping of CityGates that service a similar area.

b. EIA Efficiency Effects

Future gas demand is projected to be impacted by efficiency gains due to technology advances that allow customers to reduce natural gas consumption. A 20 year forecast of efficiency gains can be derived from the demand forecast provided by the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2014* that provides projections to 2040.

The EIA Energy Outlook report provides data based on region (census division). Cascade uses the 2014 EIA Outlook data for the entire U.S. Cascade considered using forecast data for the Pacific Region, a region, which covers both Washington and Oregon; however, this region is too heavily influenced by California and its high population, which Cascade does not serve. Cascade uses figures from EIA's reference or base case forecast which projects annual natural gas consumption for both residential and commercial customers along with expected HDDs[3] and population. Residential and commercial numbers are combined to create a single natural gas demand number for each year. A demand per population per HDD figure is calculated by dividing demand by the population and HDDs given for each year of the EIA forecast. The demand per population per HDD figure is normalized by dividing each year's calculation by year one (in this case 2014) results and is then converted to a percentage. This produces an efficiency growth[4] rate for each of the next 20 years. For this forecast, the efficiency growth rate is the same for all of Cascade's CityGates.

EIA Efficiency was calculated utilizing the equations defined below:

$TD_{[Yr]} = RD_{[Yr]} + CD_{[Yr]}$

$EIA\_E_{[Yr]} = TD_{[Yr]} / US\_POP_{[Yr]} / US\_HDD_{[Yr]}$

Definitions:

- $RD_{[Yr]}$: Residential demand from EIA's *Annual Energy Outlook 2014* by [Yr] year
- $CD_{[Yr]}$: Commercial demand from EIA's *Annual Energy Outlook 2014* by [Yr] year
- $TD_{[Yr]}$: Total natural gas demand is the summation of the residential and commercial natural gas demand for a given year
- $US\_POP_{[Yr]}$: United States population forecasted by the EIA
- $US\_HDD_{[Yr]}$: Total Heating Degree Days for the United States as forecasted by the EIA
- $EIA\_E_{[Yr]}$: Efficiency rate created using data from the EIA's *Annual Energy Outlook 2014.* This figure is normalized and converted to a percent rate.

[3] HDD or Heating Degree Day is a measure of coldness derived from the daily high and low temperature in degrees Fahrenheit. More information is provided in the weather segment of section I d. of this report.
[4] In this case, efficiency gains make for negative growth.

c. Regional Economic Demographics (W&P)

Cascade uses regional economic demographics data formulated by Woods and Poole to derive projected customer growth by town and year. Woods and Poole employment, income, population, and housing demographics were reviewed. Cascade derived population and economic growth factors formulated from Woods and Poole's forecasted population growth, and farm, manufacturing, and construction earnings.

Population Growth

Cascade uses population growth data formulated by Woods and Poole to derive projected customer growth by CityGate and year. The Woods and Poole population growth forecast is provided by county and year and directly assigned to a CityGate. Cascade assumes a 1% growth in population translates to a 1% increase in customer growth.

W&P Growth by CityGate was calculated utilizing the equations defined below:

$WP\_P_{[CityGate,Yr]} = \sum WP\_P_{[County,Yr]}$

$WP\_G_{[CityGate,Yr]} = (WP\_P_{[CityGate,Yr-1]} - WP\_P_{[CityGate,Yr]}) / WP\_P_{[CityGate,Yr]}$

Definitions:

- $WP\_P_{[Yr,\ County]}$: Woods and Poole annual population forecast based on numerous demographic factors by county and by year
- $WP\_P_{[CityGate,Yr]}$: Sum of all Woods and Poole annual population figures for all counties assigned to a CityGate
- $WP\_G_{[CityGate,Yr]}$: Woods and Poole growth factor percentage calculated from Woods and Poole population forecast by CityGate and year

Economic Growth

To develop an economic growth figure, Woods and Poole's construction, manufacturing, and farming earnings were combined for each county and year (2013-2040) to produce a total earnings number. These three industries were chosen because they describe the majority of industrial gas users in Cascade's service areas. The total economic earnings figure is divided by Woods & Poole's inflation forecast to calculate raw earnings growth. The sum of all raw earnings growth figures assigned to a CityGate was used to calculate the Economic Growth by year for each CityGate.

W&P Economic Growth by CityGate was calculated utilizing the equations defined below:

$WP\_TE_{[County, Yr]} = (WP\_CE_{[County, Yr]} + WP\_ME_{[County, Yr]} + WP\_FE_{[County, Yr]})$

$WP\_TE_{[CityGate, Yr]} = \sum WP\_TE_{[County, Yr]}$

$WP\_EG_{[CG, Yr]} = (WP\_TE_{[CityGate, Yr-1]} - WP\_TE_{[CityGate, Yr]}) / WP\_TE_{[County, Yr]}$

Definitions:

- $WP\_TE_{[County, Yr]}$: Woods and Poole total earnings from farming, manufacturing, and construction forecast by county and by year
- $WP\_TE_{[CityGate, Yr]}$: Sum of all total earning from farming, manufacturing, and construction forecast by county and by year allocated to a CityGate
- $WP\_EG_{[CG, Yr]}$: Woods and Poole economic growth percentage by CityGate and year

d. Demand Study (In House Models)

Historical Demand

Historical core monthly demand by CityGate was derived from the amalgamation and analysis of demand pulled from three sources:

- Customer Care and Billing System (CC&B) provided billing demand by town, tariff, year, and month;
- Gas Management System (GMS) provided non-core demand by CityGate, year, and month;
- Pipeline Flow Data System (EBB[5]) provided demand by CityGate, year, and month.

Cascade core demand is comprised of residential, commercial, and industrial customers assigned to core bundled gas services as defined by tariff[6]. Cascade calculates core demand by using pipeline flow data for each CityGate, which represents total gas flow for both core and non-core customers, and subtracting Cascade's non-core data by CityGate. Non-core data comes from Cascade's own Gas Management System (GMS) which tracks non-core data demand by individual customers behind each CityGate.

Core demand is improved further by a Cascade analyst who removes data that is clearly non-weather related and is atypical of Cascade's core deliveries. A review of CC&B premise counts and demand by tariff assists in identifying this data. The removed data is later reinserted into the forecast but only after the weather regressions are performed. Removing the data prior to performing the regressions improves the quality of the weather modeling[7]. Core demand by year, month, and CityGate is the primary information upon which this forecast is constructed.

Core Demand by CityGate was calculated utilizing the equation defined below:

$CD_{[CG,Yr,Mth]} = A\_P\_D_{[CG,Yr,Mth]} – NC\_GMS\_D_{[CG, Yr, Mth]} – NWD\_CD_{[CG, Yr, Mth]}$

Definitions:

- A_P_D: Actual Pipeline Demand by CityGate, year, and month.
- NC_GMS_D: Non-Core GMS Demand by CityGate, year, and month
- $CD_{[CG, Yr, Mth]}$: Core demand by CityGate, year, month
- NWD_CD: Non Weather dependent core demand, as determined by Cascade's review of C_CCB_D_A and NC_CCB_D_A (see next calculation on CC&B data)
- WD_CD: Calculated weather dependent core demand by CityGate, month, and year.

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[5] EBB or Energy Bulletin Board is a system in which pipeline companies post pipeline volumes for the benefit of buyers and sellers of natural gas.
[6] Tariff is a customer classification code
[7] See regression section of the report for more information

Core demand data can also be generated by using CC&B demand figures. However, CC&B derived demand figures were not consistent enough for use in the forecast model. Instead, the data is used only as analytical support, such as helping to identify atypical, non-weather related data. CC&B demand was allocated by town to each CityGate to determine total allocated CityGate demand by billing year and month. Analysis of the CC&B data demonstrated that billed non-core load minus one month was equivalent to non-core physical flow, due to billing operations scheduled for the last day of the month. CC&B core demand was determined to not be equivalent to physical gas flow because of differences between the billing cycle and physical gas flow.

CC&B Demand data by CityGate was calculated utilizing the equations defined below:

$D\_A\_CCB_{[CG, Tarriff, Yr, Mth]} = D\_CCB_{[Tariff, Town, Yr, Mth]} \times TGA_{[Town, CG]}$

$C\_CCB\_D\_A_{[CG, Yr, Mth]} = \sum D\_A\_CCB_{[CG, Tariff, Yr, Mth]}$

$NC\_CCB\_D\_A_{[CG, Yr, Mth]} = \sum D\_A\_CCB_{[CG, Tarrif, Yr, Mth]}$

Definitions:

- D_CCB: Raw CC&B Demand data by billing Year, Month -1, Town, and Tariff
- D_A_CCB: calculated demand where CC&B demand is allocated to each $CityGate_{CG}$ based upon the TGA
- TGA: Town to Gate Allocation (TGA) where 100 % of a town's billed volume is allocated to one or more CityGates
- C_CCB_D_A: Sum of Core CC&B Demand Allocated to the CityGate by year and month
- NC_CCB_D_A: Sum of Non-Core CC&B Demand Allocated to the CityGate by year and month

Weather

Weather Information Gathering

Historical weather is pulled from the Schneider Electric weather service for all weather related analysis. The analysis relies on the minimum (Min) and maximum (Max) temperatures per weather station and day, where National Oceanic and Atmospheric Administration (NOAA) provides an actual weather value for a weather station and day. If NOAA weather was not available for a weather station and day, a Schneider weather estimate is used.

Average Weather by Weather Station was calculated utilizing the equations defined below:

$AVG\_WS_{[WS, WD]} = \textit{Average}(MinOfTemperature_{[WS, WD]}, MaxOfTemperature_{[WS, WD]})$

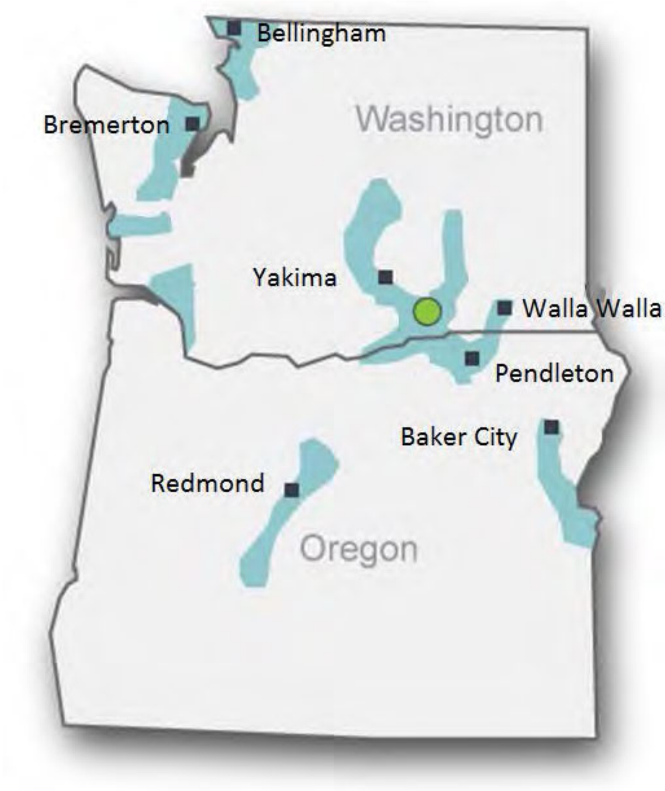
Definitions:

- $AVG\_WS_{[WS, WD]}$: calculated average temperature by $WeatherStation_{WS}$ and $WeatherDay_{WD}$
- $MinOfTemperature_{[WS, WD]}$: minimum temperature from Schneider Electric weather service by [WS] weather station and [WD] weather day
- $MaxOfTemperature_{[WS, WD]}$: maximum temperature from Schneider Electric weather service by [WS] weather station and [WD] weather day

Cascade assigns a particular weather station to represent each CityGate or demand loop it defines as a forecasting location. Seven weather stations were determined to best fit the Cascade geographic network and are located in the cities of Bellingham, Yakima, Walla Walla, Pendleton, Redmond, Baker City, and Bremerton. Considerations for selecting the weather stations are:

- Proximity of the CityGate to the weather station;
- Quality of the data available at the weather station; and
- Geographical impediments between the weather station and the CityGate.

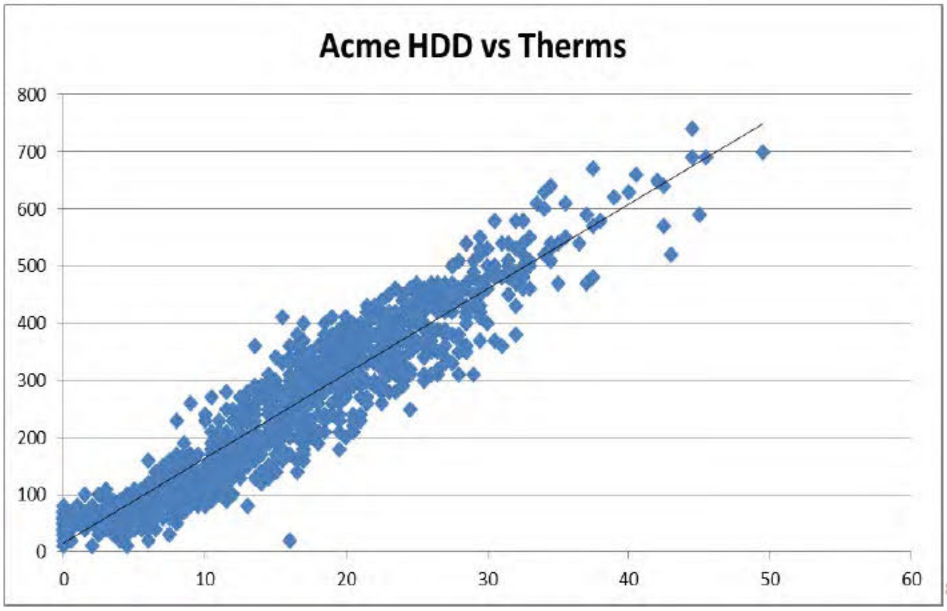
The map below shows the weather locations as well as Cascade's related customer locations (shaded in aqua).



Average weather by weather station is converted into Heating Degree Days (HDD) which become the unit of measure for the weather upon which this report is based. With weather quantified in terms of HDDs, Cascade can forecast demand scenarios based on an average year, a cold year, or a mild year. In addition, Cascade can forecast demand on peak demand days when gas loads are at their highest. Modelling various weather scenarios helps Cascade to plan for serving its customers during varying demand levels.

Heating Degree Days

Heating Degree Day (HDD) values are calculated by beginning with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from an HDD degree threshold (for example 65°F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs are never negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to notably rise. The historical threshold for calculating HDD has been 65 °F. However, Cascade's modelling demonstrates that lowering the threshold to 60 °F produces better results. The graph below shows that heating demand does not begin to increase significantly until a HDD of five (65 °F minus 60 °F) if the traditional HDD threshold of 65 °F is utilized. Lowering the HDD threshold thus gives a better measure of the relation between HDD and therms (measurement of heat usage).



8

Cascade's analysis has optimized the HDD threshold for each city gate by lowering the HDD threshold. A lower HDD threshold of 60 is used for modeling all CityGates.

Historical Premise Count

The historical premise count by year and CityGate was derived from the analysis of monthly premise counts by town and tariff pulled from the Customer Care and Billing (CC&B) system. Monthly premise counts by town, tariff, and year were allocated by town to each CityGate to determine total allocated CityGate premise count by tariff, year, and month.

Historical Premise Count by CityGate was calculated utilizing the equations defined below:

$P\_A\_CCB_{[CG, Yr, Mth, Tariff]} = P\_CCB_{[Town,Tariff,Yr,Mth-1]} \times TGA_{[Town, CG]}$

$CCB\_AAP_{[CG, Yr, Tariff]} = \text{Average}(P\_A\_CCB_{[CG, Yr, Mth, Tariff]})$

Definitions:

- P_CCB: Raw CCB premise count data by billing Year, Month -1_{Mth}, Town, and Tariff
- P_A_CCB: calculated premise count where monthly CC&B premise count by tariff is allocated to each CityGate based upon the TGA
- TGA: Town to gate allocation (TGA) where 100 % of a town's billed volume is allocated to one or more CityGates
- CCB_AAP: CC&B Average annual premise count by CityGate, tariff, and year

Growth

Growth is a calculated value which is determined based upon Woods and Poole Growth, Economic, Mixed, or a manually assigned Cascade growth adjustment plus an EIA efficiency factor. Cascade utilizes a manual growth adjustment when it determines the Woods and Poole growth figure does not best project the growth of a CityGate for a period of time. Manually assigned growth factors are based on supporting analytics related to premise growth, engineering estimates, and internal customer projections.

Growth effects are cumulative, which means that growth effects from one year carry over into the next year. However, there can occasionally be predictable events that impact demand for a specific time period but in a manner such that normal demand resumes when the event is over. For example, a factory may shut down for several months but return to full gas usage after the shutdown. This in turn would reduce CityGate demand for those months but would not affect demand thereafter. Cascade incorporates these non-cumulative events in its forecast as a manual assumption.

Forecast Adjustment Factor by CityGate and year was calculated utilizing the equations defined below:

$WP\_M_{[GC,Yr]} = [WP\_E_{[CG,Yr]} * (1- WC_{[CG]})] + [WP\_P_{[CG,Yr]} * WC_{[CG]}]$

$A\_GR_{[CG,Yr]} = \text{Select}(WP\_M_{[CG,Yr]}, WP\_E_{[CG,Yr]}, WP\_P_{[CG,Yr]}, MAG_{[GC,Yr]})$

$SA\_GR_{[CG,Yr]} = A\_GR_{[CG,Yr]} \times (GS_{[Avg,High,Low]} + 1)$[9]

$SEC\_GF_{[CG,Yr]} = SEC\_GF_{[CG,Yr-1]} *(1 + S\_GF_{[Yr,CG]} + EIA\_E_{[GC,YR]})$

$SEC\_GR_{[CG,Yr]} = (SEC\_GF_{[CG,Yr]} - 1) / 1$

$FAF_{[CG,YR,Mth]} = (SEC\_GR_{[CG,Yr]} + MA_{[Yr]} + MA_{[Yr,Mth]} + MA_{[Mth]})$

Definitions:

- $WC_{[CG]}$: Weather correlation R^2 coefficient for a CityGate
- $A\_GR_{[CG,Yr]}$: The Assigned Annual Growth Rate, represents growth by CityGate and year (This defaults to the Woods and Poole Growth rate for the CityGate and year unless a Manually Assigned Growth rate is provided)
- $WP\_P_{[GC,Yr]}$: Woods and Poole Population Growth by CityGate and year
- $WP\_E_{[GC,Yr]}$: Woods and Poole Economic Growth by CityGate and year
- $WP\_M_{[GC,Yr]}$: Mixed Woods and Poole Population and Economic Growth factors by CityGate and year
- $MAG_{[GC,Yr]}$: Manually Assigned Growth by CityGate and year
- $SA\_GR_{[CG,Yr]}$: The Assigned Scenario Growth Rate, represents A_GR impacted by the selected growth scenario
- $GS_{[Avg,High,Low]}$: Growth Scenario Impact for average, high, and low growth given in percent terms
- $EIA\_E_{[GC,Yr]}$: EIA Efficiency factor by year
- $SEC\_GF_{[CG,Yr]}$: Applied Annual Growth Factor (With EIA Efficiency), by CityGate and year that is compounded
- $SEC\_GR_{[CG,Yr]}$: Applied Annual Growth modified from a factor to percent rate
- $FAF_{[CG,Yr,Mth]}$: Final Forecast Adjustment Factor by CityGate, year, and month
- $MA_{[Yr]}$: A Manual Forecast Adjustment Factor that affects a given year
- $MA_{[Yr,Mth]}$: A Manual Forecast Adjustment Factor that affects a given month in a given year
- $MA_{[Mth]}$: A Manual Forecast Adjustment Factor that affects a given month for all years

[9] This formula changes depending on whether the assigned growth rate is positive or negative and the growth scenario (high or low). See growth scenario section for more details.

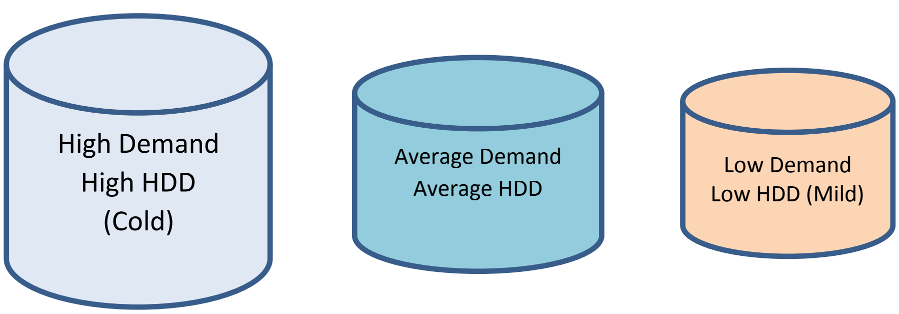
Weather Scenarios

The study models three weather scenarios: medium, high and low temperature. To determine the average (medium) weather case scenario, the average HDD of each month is taken from a specified range of years for each of the seven weather locations. This forecast uses a 30 year range of weather history from the years 1984 through 2013 for each of the three scenarios.

To determine the high case HDD weather scenario, Cascade selects the years representing the six coldest years (20% of the coldest years out of 30). These are the particular years with the highest system HDD. Finding the system HDD involves considering HDDs from all seven weather stations and giving appropriate weight to the weather stations that have greater impact on system wide demand. The weighting factor is determined by adding the coefficients or factors (derived from the regression[10]) for each weather station, and by then dividing the sum of the coefficients by the total value of the coefficients from all of the weather stations. Thus the system weighted HDD is the summation of HDDs from each weather station multiplied by its weighting factor. The system calculated HDDs are used to rank the years from warmest to coldest.

To determine the low case HDD weather scenario, Cascade selects the years representing the six warmest years (20% of the warmest years out of 30). These are the particular years with the lowest system wide HDD. For both the high and low case HDD weather scenarios, for each particular month of a given projected future year, the HDD from these six years are averaged to provide the appropriate scenario.

Weather Scenarios



[10] Refer to regression section of this report for more information.

Cascade Weather Scenario Impact

Weather Scenario Impact by Weather Station was calculated utilizing the equations defined below:

$AWS_{[Avg,\ Mth]} = Average(HDD_{[All\ Weather\ YRS,\ Mth]})$

$HWS_{[High,\ Mth]} = Average(HDD_{[Top\ X\ YRS,\ Mth]})$

$LWS_{[Low,\ Mth]} = Average(HDD_{[Bottom\ Y\ YRS,\ Mth]})$

Definitions:

- $AWS_{[Avg,\ Mth]}$: Average HDD by month for all weather years
- $HWS_{[High,\ Mth]}$: Average HDD by month for the X years with the highest HDD values (coldest), where X is the number of weather years multiplied by the weather range, e.g. 30 years * 20% = 6 years
- $LWS_{[Low,\ Mth]}$: Average HDD by month for the Y years with the lowest HDD values (warmest), where Y is the number of weather years multiplied by the weather range, e.g. 30 years * 20% = 6 years

Growth Scenarios

Cascade has defined three growth scenarios to adjust expected demand:

- Expected growth: is the calculated Annual Cascade Assigned Scenario Impact growth projection
- High Growth: is the High Cascade Assigned Scenario Impact
- Low Growth: is the Low Cascade Assigned Scenario Impact

Each scenario calculates a single growth factor to increase or decrease demand at a given CityGate in a given year over the projected 20 year period.

Cascade Growth Scenario Impact

High and low growth scenarios are defined by a banded +/- ranged based upon the average assigned scenario growth defined.

Growth Scenario Impact by CityGate and Year was calculated utilizing the equations defined below:

$SA\_GR_{[AVG, CG, Yr]} = SA\_GR_{[YR,CG]}$

$SA\_GR_{[High]}$ = If $A\_GR_{[YR,CG]} > 0$, THEN = $A\_GR_{[YR,CG]} * (1+GS_{[High]})$, ELSE = $A\_GR_{[YR,CG]} * (1-GS_{[High]})$

$SA\_GR_{[Low]}$ = If $A\_GR_{[YR, CG]} > 0$, THEN = $A\_GR_{[YR,CG]} * (1-GS_{[High]})$, ELSE = $A\_GR_{[YR, CG]} * (1+GS_{[Low]})$

Definitions:

- $GS_{[Avg, High, Low]}$: Growth based upon scenario Avg, High, or Low
- $A\_GR_{[CG, Yr]}$: The Assigned Annual Growth Rate, represents growth by CityGate and Year (This is the Population/Economic/Mixed Woods and Poole Growth factor for the CityGate and Year unless a Manually Assigned Growth factor is provided)
- $GS_{[High]}$: High Growth Range Adjustment is a model variable represented as %
- $GS_{[Low]}$: Low Growth Range Adjustment is a model variable represented as %

Regression Analysis

The majority of Cascade's core natural gas demand is used for heating purposes and is highly dependent on the weather. The colder the weather, the greater the demand. To forecast weather dependent load which accounts for weather differences, Cascade conducted a linear regression[11] analysis to develop a regression coefficient and constant for each CityGate. Cascade preformed a regression analysis of weather dependent monthly gas demand in comparison with monthly heating degree days at each CityGate for Historical Demand. The regression analysis calculated the coefficient ***b*** and constant ***C*** that best minimizes the error. This forecast uses a linear regression, no exponents were used[12].

Regression analysis calculates the best coefficient *b* and constant *C* values for each CityGate *utilizing the equations defined below*:

$$\boldsymbol{Demand = b \times HDD + C}$$

Definitions:

- Demand = Core Weather Dependent Gas Demand (Daily Average for a given month in dekatherms)
- HDD = Average Heating Degree Day Per month
- b = coefficient that gives gas demand (dekatherms) per HDD
- C = constant, base level of gas demand (dekatherms) that remains the same regardless of weather

The coefficient ***b*** is the central figure in the model when calculating weather dependent demand. It best describes the impact that weather has on gas demand. The larger the ***b*** coefficient, the greater the gas demand per unit of weather. The constant ***C*** is the base level of gas demand (dekatherms) that remains the same regardless of weather.

In addition to finding the coefficient ***b*** and the constant ***C***, another product of the regression analysis is the production of the correlation coefficient, *R*. This figure is typically squared to form R^2. R^2 measures the strength of the relationship between two variables. R^2 values can range from zero to one. A regression with an R^2 of 1 means it has been a perfect predictor of demand, and therefore, would be an ideal regression to use. An R^2 of 1 does not guarantee a future HDD will predict the exact demand. A low R^2 value shows that it has not been a good predictor, and therefore, would not be an ideal regression to use.

[11] Regression analysis is a statistical process used to study the relationship between variables – in this case weather and demand.

[12] Cascade considered using exponential and more complex statistical techniques to find the relationship between weather and demand. However, Cascade saw only negligible gains in regression quality that did not merit the additional complexity.

For the purposes of this forecast, Cascade did not require the use of a Monte Carlo[13] model to calculate weather. There was sufficient historical weather data to produce high, low, and medium cases without utilizing a Monte Carlo simulation.

e. Demand Study (Calculation)

Monthly Demand Forecast

The Monthly Demand Forecast by CityGate, year, and month is based upon the calculated forecast for weather dependent core load plus the most recent year's (2013) non weather dependent core load where a single forecast adjustment was applied which included growth and Cascade assumptions.

Weather dependent core load was forecasted by CityGate utilizing the Weather Dependent Model equation, unless the R^2 of a CityGates linear regression was below a certain 80% threshold, meaning HDD is not a good predictor of demand.

Forecast Demand by CityGate, Year, and Month was calculated utilizing the equations defined below:

$WDD_{[CG,YR,Mth]} = (b_{[CG]} \times HDD_{[High, Ave, Low, CG,Mth]} + C_{[CG]})* DAYS_{[Yr,Mth]} + NWDDV_{[CG,YR,Mth]}$

$MDF_{[CG,YR,Mth]} = Or(WDD_{[CG,YR,Mth]}, DDV_{[CG,YR,Mth]}) * (1+FAF_{[YR,Mth,CG]})$

Definitions:

- WDD: Weather based demand for a given weather scenario for a given CityGate and month
- b: coefficient that gives gas demand (dekatherms) per HDD for a given CityGate
- C: constant, base level of gas demand (dekatherms) that remains the same regardless of weather
- DAYS: Number of days in forecast year and month
- NWDDV: Non Weather Dependent Default Demand Value based upon forecast month
- DDV: Default demand value per CityGate based upon forecast month
- MDF: Monthly demand forecast per CityGate
- FAF: Forecast Adjustment Factor by CityGate, year, and month (Includes growth, assumptions, and scenario impact)

[13] Monte Carlo modeling is a statistical method used to estimate solutions for complex equations that cannot be solved for implicitly. The technique typically involves averaging the results of multiple trials using random input figures. For this forecast, the primary inputs, including weather, were defined well enough that the use of Monte Carlo is not necessary.

System Peak Forecast

The purpose of finding the peak demand day is to ensure that Cascade can continue to provide adequate heating to its customers even under extreme conditions which are far colder than the norm. There are 3 scenarios that are analyzed in the forecast model:

- Expected peak day;
- System wide max peak day;
- Max CityGate peak day.

Expected peak day demand in a given year, in contrast with the highest case scenario peak day demand, is calculated by Cascade based on the average of the peak demand days for each of the last 30 years. Initially, the system-weighted peak day, which is later explained, is found for each year for the last thirty years. The actual HDD from each of those 30 peak days is averaged for each weather station resulting in an average peak HDD. Applying the associated average peak HDD to the forecast model for each CityGate yields an expected peak demand for each CityGate. Cascade calculates the expected peak demand for each CityGate for each future year of the forecast by applying appropriate growth factors.

Cascade determines the system wide max peak demand day by first selecting the system wide single coldest day recorded in the past 30 years. To determine the system wide max peak demand day, HDDs from all seven weather stations are considered, giving appropriate weight to the weather stations having the greater impact on system wide demand. This same method is used in the weather scenario section of this report in order to find the coldest and warmest years. The calculation of the system weighted HDD is applied to the previous 30 years of weather data to determine the highest HDD of all. Cascade has found December 21, 1990 to be the highest system weighted HDD for this period.

The peak demand day is then derived from the highest HDD by applying the actual HDD from the peak day for the 30 year period to the monthly linear regression equation for each CityGate[14]. Thus, all CityGates associated with the Bellingham weather station, for example, use the HDD calculated for Bellingham for December 21, 1990 and similarly for all the other weather stations and CityGates. This provides a highest demand scenario for peak demand load based on 30 years of weather history for each CityGate. To determine the peak demand day for a given projected year, growth factors (see below) are applied to the peak demand day for the thirty year period. Peak day demand is in turn calculated for each CityGate for each year of the twenty year forecast.

[14] See regression section of this report

The max CityGate peak day is determined by finding the coldest HDD for each weather station in the 30 year history and combining those to model occurrence in one day. The difference between the system wide max peak day and the max CityGate peak day is that the system wide max peak day is the historical day that maximized the entire system demand, whereas the max CityGate peak day is a theoretical scenario where the coldest HDD for each weather station occurs on the same day.

For CityGates where demand is not weather dependent, the peak demand day cannot be calculated by applying an associated HDD. Instead, peak demand for these CityGates becomes the average daily demand for the month in which the system peak day falls. Cascade applies the calculated Daily Peak Adder (DPA) to the average daily demand number to convert the average day figure to daily peak demand. As with the weather dependent peak days, growth factors are applied to this figure.

PeakDemand by CityGate and year was calculated utilizing the equations defined below:

$DDmax_{[CG,Yr]} = (b_{[CG]} \text{ x } HDDpmax_{[day]} + C_{[CG]})$

$DDavg_{[CG,Yr]} = (b \text{ x } HDDpavg_{[day]} + C)$

$MPDF_{[CG,Yr]} = (DDmax_{[CG,Yr]})*(1+FAF_{[CG,Yr]})$ OR

$(DDV_{[CG,Yr,Mth]})/ DAYS_{[Yr,Mth]})* (1+FAF_{[CG,Yr]})*(1+DPA)$

$EPDF_{[CG,Yr]} =(DDavg_{[CG,Yr]})*(1+FAF_{[CG,Yr]})$ OR

$(DDV_{[CG,Yr,Mth]})/ DAYS_{[Yr,Mth]})* (1+FAF_{[CG,Yr]})*(1+DPA)$

Definitions:

- HDDpmax: HDD of an associated weather station on the historical peak day
- HDDpavg: Average of the weather station's HDDs from the historical peak days of each of the last 30 years
- DDmax: Daily demand based on a max peak HDD
- DDavg: Daily demand based on an average peak HDD
- b: coefficient that gives gas demand (dekatherms) per HDD
- C: constant, base level of gas demand (dekatherms) that remains the same regardless of weather
- DAYS: Number of days in forecast Year and Month
- DDV: Default monthly demand value per CityGate based upon month of peak demand day
- MPDF: Max peak demand day forecast per CityGate
- EPDF: Expected peak demand day forecast per CityGate
- FAF: Forecast Adjustment Factor by CityGate, Year (Includes Growth, Assumptions, and Scenario Impact)
- DPA: Default peak adder based on user input

Annual Premise Count Trend Forecast

The Annual Premise Count Projection by CityGate and year was based upon a linear trend analysis of the Historical Premise Count data pulled from CC&B for a CityGate, tariff, and year. Historical Premise Count by CityGate, tariff, and year was used to forward project premise count based upon the trend between premise count and time. This information is used as guide to assist Cascade when forecasting customer growth.

Premise Trends by CityGate where calculated utilizing the equations defined below:

$FPC_{[CG,Tariff,Yr]} = Trend(CCB\_AAP_{[CG,Tariff,Yr]}, Time_{[Yr]})$

Definitions:

- CCB_AAP: CCB Average Annual Premise count by CityGate, tariff, and year.
- Time: Years Raw CCB premise count data was provided
- FPC: Forward projection of annual premise count by CityGate, tariff, and year.

f. Assumptions Weather

- Forecast is based off of core data
- Core data is sourced from the pipeline company and from Cascade GMS (Gas Management System)
- Weather at each CityGate is represented by weather at one of the seven weather locations.
- HDDs, on a 60 F threshold, are used to measure units of coldness
- The time period for finding historical weather is the past 30 years (1984-2013).
- The average weather case scenario is based on normal weather- the average monthly HDD of a historical time period of 30 years.
- The high case weather scenario uses the monthly average from the six coldest system wide years out of 30.
- The low case weather scenario uses the monthly average from the six warmest system wide years out of 30.

Linear Regression Model

- A linear regression model is used to model demand based on weather.
- Cascade refers to the most recent year (2013) for CityGates that have regressions (R^2) less than a certain value assigned by Cascade (80%).

Growth

- The forecast uses outside consulting firm Woods & Poole's forecast for population growth.
- The forecast model assumes that 1% increase in population translates to a 1% increase in gas demand, before accounting for any efficiency gains.
- The EIA efficiency factor is derived from the 2014 EIA Annual Energy Outlook.

II. Glossary of Terms and Assumptions

Core Customers – These are full service customers of Cascade that pay a delivered price of gas. These are typically residual and commercial customer users.

Non-Core Customers – These customers pay Cascade the cost of transporting the gas to Cascade and purchase the gas from another source.

Premise Count – Customer count.

NOAA – National Oceanic Administration Association, the federal agency that is the primary weather data holder for the United States.

Regression – A method of comparing two different data sets in which factors are calculated to predict one data set to the other. The closer the predicted set to the actual set the better the regression.

Correlation – A measure of the regression of between two data sets. The higher the regression or relation between two data sets the higher the correlation. Correlation figures range from zero to one.

HDD – Heating Degree Day – A unit to describe unit of coldness.

CityGate – This marks the point where the gas utility, Cascade, delivers gas from the gas pipeline company to a large group of customers.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

Micah Robinson
Exhibit No. 402

Twenty-Year Demand Oregon Forecast by CityGate

Cascade Natural Gas Corporation
20-year Oregon forecast by CityGate

Forecast Time	OR Forecast (Therms)	ATHENA	BAKER	UMATILLA	CHEMULT	GILCHRIST	HERMISTON	HUNTINGTON	LA PINE	MADRAS	MILTON-FREEWATER	MISSION TAP	NYSSA-ONTARIO	PENDLETON	PRINEVILLE	REDMOND	STANFIELD	STEARNS (SUNRIVER)	DAVE RASMUSSEN	PRONGHORN	SOUTH HERMISTON	KOSMOS FARMS	Bend Loop
2015	74,229,686	429,400	3,541,222	1,939,721	49,811	215,103	5,251,507	76,210	465,844	2,748,888	417,902	449,334	5,458,373	6,180,686	2,851,608	7,565,311	217,315	4,470,395	-	554,489	-	-	31,346,564
2016	75,702,992	434,175	3,562,791	1,959,822	50,113	217,395	5,308,033	76,734	478,280	2,773,777	422,485	454,083	5,499,981	6,247,283	2,878,811	7,770,131	219,708	4,590,504	-	566,906	-	-	32,191,977
2017	76,495,517	434,621	3,550,039	1,963,040	50,417	217,696	5,315,364	76,400	486,528	2,773,465	423,119	454,798	5,488,814	6,255,841	2,879,442	7,904,383	219,958	4,670,755	-	579,341	-	-	32,751,495
2018	77,635,149	437,278	3,555,107	1,974,912	50,724	219,019	5,347,854	76,509	496,921	2,786,376	425,766	457,578	5,504,496	6,294,080	2,894,024	8,074,371	221,302	4,771,202	-	591,800	-	-	33,455,830
2019	78,778,165	439,967	3,560,176	1,986,912	51,033	220,355	5,380,740	76,618	507,343	2,799,632	428,440	460,392	5,520,483	6,332,784	2,909,006	8,244,563	222,663	4,871,770	-	604,274	-	-	34,161,015
2020	80,283,682	444,893	3,582,501	2,007,669	51,341	222,725	5,439,067	77,159	520,071	2,826,132	433,152	465,292	5,563,286	6,401,504	2,938,086	8,453,151	225,132	4,994,025	-	616,739	-	-	35,021,758
2021	81,068,179	445,372	3,570,533	2,011,061	51,651	223,051	5,446,842	76,841	528,249	2,826,945	433,805	466,048	5,552,721	6,410,582	2,939,901	8,585,071	225,398	5,072,978	-	629,231	-	-	35,571,897
2022	82,215,176	448,099	3,575,822	2,023,253	51,961	224,405	5,480,190	76,955	538,731	2,841,012	436,507	468,901	5,568,977	6,449,831	2,955,681	8,755,346	226,778	5,173,595	-	641,711	-	-	36,277,422
2023	83,361,247	450,820	3,581,111	2,035,402	52,270	225,763	5,513,472	77,069	549,223	2,855,193	439,201	471,749	5,585,209	6,489,002	2,971,594	8,925,456	228,156	5,274,114	-	654,179	-	-	36,982,267
2024	84,892,554	455,850	3,603,979	2,056,585	52,579	228,180	5,573,020	77,621	562,218	2,882,995	443,998	476,751	5,628,744	6,559,160	3,001,905	9,137,284	230,676	5,398,203	-	666,653	-	-	37,856,150
2025	85,654,098	456,279	3,591,908	2,059,786	52,886	228,481	5,580,234	77,301	570,250	2,884,253	444,596	477,461	5,617,617	6,567,577	3,004,085	9,265,429	230,918	5,475,006	-	679,097	-	-	38,390,932
2026	86,799,019	459,000	3,597,197	2,071,956	53,193	229,842	5,613,517	77,415	580,780	2,898,903	447,282	480,309	5,633,797	6,606,748	3,020,530	9,435,169	232,296	5,575,307	-	691,538	-	-	39,094,242
2027	87,942,098	461,722	3,602,486	2,084,105	53,499	231,199	5,646,799	77,529	591,311	2,913,676	449,966	483,157	5,649,950	6,645,919	3,036,975	9,604,579	233,673	5,675,413	-	703,954	-	-	39,796,188
2028	89,486,391	466,780	3,625,015	2,105,372	53,802	233,629	5,706,642	78,075	604,512	2,942,121	454,780	488,182	5,693,226	6,716,425	3,067,996	9,818,441	236,207	5,800,623	-	716,350	-	-	40,678,213
2029	90,219,473	467,121	3,612,623	2,108,233	54,103	233,893	5,712,835	77,747	612,370	2,943,466	455,287	488,807	5,681,383	6,723,639	3,070,131	9,942,288	236,406	5,874,967	-	728,706	-	-	41,195,470
2030	91,353,298	469,799	3,617,471	2,120,191	54,402	235,231	5,745,588	77,851	622,895	2,958,483	457,924	491,609	5,696,825	6,762,188	3,086,709	10,110,504	237,761	5,974,367	-	741,035	-	-	41,892,465
2031	92,487,490	472,483	3,622,320	2,132,169	54,700	236,570	5,778,408	77,956	633,437	2,973,506	460,563	494,418	5,712,404	6,800,814	3,103,553	10,278,678	239,119	6,073,742	-	753,361	-	-	42,589,288
2032	94,042,547	477,563	3,644,724	2,153,497	54,997	239,009	5,838,471	78,499	646,830	3,002,468	465,386	499,460	5,755,413	6,871,582	3,135,023	10,494,259	241,664	6,199,888	-	765,657	-	-	43,478,155
2033	94,749,799	477,834	3,632,017	2,156,063	55,292	239,241	5,843,849	78,164	654,534	3,003,897	465,818	500,017	5,742,864	6,877,835	3,137,108	10,614,160	241,827	6,271,981	-	777,950	-	-	43,979,347
2034	95,879,394	480,501	3,636,866	2,167,978	55,586	240,574	5,876,471	78,269	665,096	3,019,274	468,434	502,808	5,758,223	6,916,228	3,154,084	10,781,592	243,177	6,370,918	-	790,222	-	-	44,673,094

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

Micah Robinson
Exhibit No. 403

2015 Oregon Customer and Volume Forecast

Cascade Natural Gas Corporation
2015 Oregon customer and volume forecast by tariff

Oregon Customer Count Forecast					
Year	CNGOR101	CNGOR104	CNGOR105	CNGOR111	CNGOR170
2015	711,020	118,063	1,331	156	48

Oregon Volume Forecast (Therms)						
Year	CNGOR101	CNGOR104	CNGOR105	CNGOR111		CNGOR170
				Commercial	Industrial	
2015	39,442,028	27,905,898	2,533,883	548,762	1,031,083	2,768,032

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

DIRECT TESTIONY OF RONALD J. AMEN
REPRESENTING CASCADE NATURAL GAS CORPORATION

LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN

DIRECT TESTIMONY – LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN

Contents

Regulatory Affairs
Cascade Natural Gas Corporation
8113 W. Grandridge Blvd.
Kennewick, WA 99336

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Cascade Natural Gas Corporation ("Cascade" or the "Company").

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Corporation (Black & Veatch) as a Director and I am a member of the Financial & Regulatory Services Practice within Black & Veatch Management Consulting.

Q. Please describe the firm of Black & Veatch.

A. Black & Veatch has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Black & Veatch Management Consulting delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch Management Consulting delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas.

Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis, and regulatory practices and policies gained through

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management and operating responsibilities at gas distribution, pipeline, and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 35 years of experience in the utility industry, the last 17 years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A to my testimony.

Q. Have you previously testified before any utility regulatory bodies?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission (FERC) and numerous state and provincial regulatory commissions, including oral testimony before the Oregon Public Utility Commission ("OPUC" or the "Commission").

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Q. Please summarize your testimony.

A. In my testimony I present Cascade's Long-Run Incremental Cost ("LRIC") Study and discuss its results, and I present the various rate design proposals filed by Cascade in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- Cascade's LRIC Study
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Summary of Cascade's Rate Design Proposals
- Residential & Non-Residential Class Bill Impacts

Q. Please provide a list of exhibits supporting your testimony.

A. The following exhibits accompany my testimony.

- Exhibit CNG/501 Summary of LRIC
- Exhibit CNG/502 Incremental Plant Carrying Costs
- Exhibit CNG/503 Incremental O&M Costs
- Exhibit CNG/504 Summary of Revenue by Rate Class
- Exhibit CNG/505 Analysis of Revenue by Detailed Rate Schedule
- Exhibit CNG/506 Residential Impact by Month
- Exhibit CNG/507 Impact of Recommended Rate Changes

II. THEORETICAL PRINCIPLES OF COST ALLOCATION

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Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an LRIC study is a useful tool for determining the allocation of Cascade's revenue requirement among its rate schedules. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the change in costs associated with a one unit change in service (or output) provided by the utility. LRIC is a variant of the marginal cost approach that examines changes in costs over a longer time period associated with a multiple unit (*i.e.*, incremental) change in service. As a result of using an incremental change, capacity additions tend to be lumpy and may reflect more capacity additions than those required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets

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prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Marginal cost studies can reflect actually incurred costs but often rely on estimates of the expected changes in cost associated with changes in utility service. Marginal cost studies are forward-looking to the extent permitted by available data. Marginal cost studies are particularly useful for rate design and can also be used as a guide to determine how a utility's total revenue requirement should be allocated to its classes of service. Where it is important to send appropriate price signals associated with additional energy consumption by customers, an understanding of marginal cost may be useful. For a gas utility, detailed studies are not required to assess the impact of additional consumption by existing customers since the delivery system is built for design day requirements and energy conservation has reduced those requirements for most customers. Where new customers are added to the system, growth may increase design day requirements above an amount that existing facilities can serve. The principal factors driving new main investment are customer growth and the replacement of bare steel and cast iron mains to provide safe and reliable service for customers.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed

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costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the

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assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the information developed in the cost of service study to understand and quantify the allocated costs in each rate class to guide the development of rates is a useful step in the rate design process.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds marginal cost, but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed marginal cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for Cascade because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above

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marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. From a cost of service perspective, the best approach is to directly assign costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate schedule, or class, uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. Please discuss the elements of Cascade's LRIC analysis.

A. As I introduced earlier, LRIC is a costing method based on principles of marginal costs. Since marginal costs are forward-looking in nature, they require making estimates of future costs with an understanding of the elements that drive those future costs.

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To estimate LRIC, the first step requires determining the change in cost associated with the incremental consumption of natural gas. For LRIC, the increment may be defined as the number of customers, the design day demand, or the additional commodity. In this case, there is no reason to estimate the incremental commodity because gas costs are a pass-through cost element. Essentially, LRIC requires an understanding of the utility's system planning process. Often, however, the planning process does not provide all of the information necessary to develop complete LRIC estimates.

The second step in the determination of LRIC relates to the change in capacity requirements as measured by the utility's design day demand. Unlike the commodity determination, there is no competitive market for the utility's distribution function. Thus, it is necessary to estimate how customers' demand for design day capacity influences the costs for distribution. The capacity requirements for the distribution system must reflect the non-coincident demands on the system since delivery must satisfy the local demands of customers that may not be coincident with the system peaks for a number of reasons. Although, for customers who use the utility's gas delivery system for heating as opposed to process usage or interruptible services, their demands tend to be coincident. For process and interruptible customers, LRIC is zero for existing customers unless the customer expands its operations. If expansion occurs, LRIC is the cost incurred to expand capacity to meet the customer's increased contracted demand.

III. CASCADE'S LRIC STUDY

Q. Have you prepared Cascade's LRIC Study filed in this proceeding?

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A. Yes. Exhibit CNG/501 presents Cascade's LRIC Study. In particular, the exhibit presents the resulting allocation by rate schedule of Cascade's proposed revenue requirement based strictly on the results of the LRIC computations included in the LRIC Study.

Q. Please describe the methodology used to prepare Cascade's LRIC Study.

A. Cascade has chosen to follow a similar methodology as that employed recently by Avista Utilities in OPUC Docket No. UG-246. The primary elements of Cascade's LRIC Study are incremental plant investments and incremental operations and maintenance expenses ("O&M"). The incremental cost information related to these elements are accumulated on a cost per customer basis for each of Cascade's tariff rate schedules summarized to represent the long-run incremental cost for customers on Cascade's distribution system.

A. Incremental Plant Investment Costs

Q. What are the components of Cascade's increment plant investment?

A. Cascades' incremental plant investment has three primary components. These components are:

1. The costs to install distribution mains in order to: a) connect new customers, b) provide capacity reinforcements to both new and existing customers, c) address safety and reliability requirements for the benefit of all customers, and d) invest in long-term system main replacement;
2. The cost to provide a service line to connect new customers; and
3. The cost to provide a meter and regulator to serve new customers.

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Q. How is the cost to install distribution mains determined for the various functions described in the previous response?

A. The first component of Cascade's distribution mains analysis derives the customer related costs associated with the installation of distribution mains to connect new customers. Mains investments that serve this function were extracted from Cascade's plant accounting records. Oregon new business project work orders were summarized for a twelve-year period (2002 – 2013). The customer cost was computed by taking the average cost per foot of Cascade's minimum-sized distribution main (two-inch), escalated to current dollars (2014) using the Handy Whitman Index of Public Utility Construction Costs, and multiplying that unit cost by the average number of feet of main installed per new customer for Residential (Schedule No. 101), Commercial (Schedule No. 104), and Industrial (Schedule No. 105) service classes. For the larger core classes (Schedule No. 111 and Schedule No. 170) and the non-core classes (Schedule No. 163 and Schedule No. 164), as well as the Special Contract Class (Schedule No. 900), the distribution main segments connected to the individual customers were identified using Cascade's Geographic Information System ("GIS"). The in-service date of the main segment, its size, type and length were compiled and current costs (2014 dollars) applied to compute the corresponding installed costs.

Q. How were the incremental costs of distribution mains determined for system capacity reinforcement, and safety and reliability investments?

A. Incremental mains investment that serve these two functions were extracted from Oregon project work orders and were summarized for a five-year historic period (2009 – 2013) and five-year budget forecast (2015-2019). The reinforcement projects are

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considered capacity-related and allocated to Cascade's core classes on the basis of their contribution to the system peak day. Targeted reinforcement projects attributable to the Special Contract class for the five-year budget period were directly assigned to this class.

The safety and reliability projects are considered commodity-related and were therefore allocated to all classes except for the Special Contract class on the basis of annual throughput.

Q. How were the incremental cost of distribution mains determined for long-term system replacement investments?

A. Long-term distribution mains replacement costs were estimated by calculating the current cost of Oregon mains in service at December 2013. Current costs of the prior three categories of distribution mains, new customer main extensions, reinforcement, and safety and reliability investments, were deducted to determine the remaining level of system replacement investment. This remaining investment was separated into capacity versus commodity components using Cascade's Oregon system load factor and then allocated to the appropriate classes using design day demand and annual throughput, respectively.

Q How were the incremental costs for the four categories of mains then computed for the LRIC Study?

A. Once the investment costs for all mains were derived, the incremental costs were computed by applying an Economic Carrying Charge Rate ("ECCR") to the investment costs. The derivation of the LRIC for distribution mains is presented in Exhibit CNG/502, Plant Carrying Costs.

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Q. How are the costs of services, meters, and regulators determined?

A. Cascade's LRIC Study derives the incremental costs of installing new services using Cascade's recent actual installation costs from 2009 to 2013 escalated to 2014 dollars using the Handy Whitman Index of Public Utility Construction Costs. For services, the investment costs are based on the installed cost for customers' typical size and type for each core customer class 101, 104 and 105. Similarly, the investment costs for meters and regulators are based on the installed average cost of metering and regulating equipment for these core classes utilizing current 2014 inventory prices. For the remaining larger customer classes 111, 170, 163/164, and the Special Contract class 900, the service, metering and regulating installations were specifically identified for each customer using the Cascade GIS system and then valued at current cost. Once the investment costs were derived, the incremental costs were computed by applying the ECCR to the investment costs. The derivation of the LRIC for services and meters is presented in Exhibit CNG/502.

Q. How does the investment in meters, services and mains impact LRIC calculation through the use of the ECCR?

A. The investment in meters, services and mains plant are multiplied by an ECCR to arrive at an annualized cost associated with these capital investments. Separate ECCRs were calculated for meters, services and mains. The three ECCRs are different because asset life and depreciation methods are different for each of these asset classes.

Q. Please explain the Economic Carrying Charge Rate.

A. The ECCR is defined as the levelized economic cost per unit of book value investment. Economic cost reflects true cost associated with owning and operating an asset. It is

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different from expenses in that it accounts for return on capital that is required to make an investment. The carrying charge includes: a) a required return on and of capital component, b) an operations and maintenance cost component, c) an administrative and general cost component, and d) corresponding tax effects.

B. Incremental Operating & Maintenance Expenses

Q. Please identify the costs included in gas supply related O&M expenses and how these costs were treated in the LRIC?

A. The category of gas supply O&M expenses includes salaries and benefits of personnel in the following responsibility centers: Gas Supply Resource Planning (RC 4761100), Gas Supply (RC 4761200), Gas Control (RC 4763200), and a Management expense allocation from MDU (RC 4766000). The corresponding labor expenses were distributed among the three categories of Gas Planning, Gas Supply and Gas Control based on the time allocations reported by the personnel in these responsibility centers.

The Gas Planning function includes monthly/seasonal/annual gas resource planning; supply resource modeling and optimization; market intelligence gathering and analysis; IRP development; and Canadian / U.S. pipeline and storage operational, tolls / tariffs, and shipper related activities. The expenses charged to this function were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using a peak & average allocator.

The Gas Supply function includes gas supply procurement for core customers; balancing of core system supplies, including day-to-day storage activities; gas supply

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reporting, including commodity and closing price reporting; processing supplier invoices; updating and maintaining North American Energy Standards Board (NAESB) contracts; and tracking import authorizations and North American Free Trade (NAFTA) certificates. Types of activities relating to non-core customers include resolution of imbalances and communicating with non-core customers relating to imbalance “packing” or “drafting” that affects the overall system balance position. The expenses charged to this function were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

The Gas Control function entails the 24-hour daily monitoring and management of the flow of gas on the Cascade pipeline system in Oregon. This is accomplished by gas control personnel through electronic monitoring of various points on the system via SCADA and Metretek measurement equipment. The SCADA sites are located at town border stations throughout the Cascade system and at one Special Contract customer location. Metretek monitoring equipment is located at non-core customer locations for classes 170, 163/164 and 900. The expenses charged to this function were first segregated between core and non-core classes according to a recent twelve-month study of recorded actionable items triggered by information provided by the SCADA and Metretek sites, and then allocated among the core and non-core classes using sales or transportation volumes, respectively. The results of the foregoing allocations of gas supply related O&M are shown on Line 33 of Exhibit CNG/503.

Q. Please describe the costs included in incremental customer service related O&M expenses and how these costs were treated in the LRIC Study.

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A. The category of incremental customer related O&M expenses includes Meter Reading (FERC Account 902); Customer Records and Collections, including monthly billing postage and printing (FERC Account 903); and Uncollectible Accounts (FERC Account 904), involving the following Cascade Responsibility Centers: Customer Services (RC 4767100, RC 4767200); Credit and Collections (RC 4767000); Revenue Accounting (RC 4760700); Information Systems (RC 4767800); and Oregon Districts (Bend RC 47041/47044), Pendleton (RC 47042), and Eastern Oregon (RC 47043).

Meter Reading expenses were assigned to core or non-core customer groups based on an analysis of labor costs of field personnel involved in meter reading activities related to the respective customer groups and then allocated on a customer basis. Customer Records and Collections expenses were allocated to all classes on a customer basis after first directly assigning a portion of the expenses to the classes that receive manual billing (i.e., 163/164, 170, and 900). Uncollectible Accounts expenses were assigned to the classes on the basis of uncollectible account write-offs. The results of the foregoing allocations of customer service related O&M are shown on Line 57 of Exhibit CNG/503.

C. LRIC Summary of Results

Q. Please compare the resulting LRIC estimates to the current rates and associated non-gas revenues for each of Cascade's rate schedules.

A. Line 40 of Exhibit CNG/501presents the total LRIC-based revenue requirement for each of Cascade's rate schedules. Line 38 of this Exhibit presents Test Year revenues by rate schedule under Cascade's current rates. By comparing these two sets of revenues,

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one can see the extent to which Cascade's current rates and non-gas revenues are reflective of LRIC. The revenue-to-cost ratios on line 41 of this exhibit portray the relative difference between these two revenue amounts for each rate schedule. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the particular rate schedule are below its indicated LRIC (*e.g.*, Rate Schedule 101, 104, 105, 111, 163/164), while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the rate schedule are above its indicated LRIC (*e.g.*, Special Contract Class 900). These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures. I will describe later in my testimony how these results were used to assign Cascade's proposed revenue increase to its rate classes.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you have relied upon as the basis for Cascade's rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

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These rate design principles draw heavily upon the “Attributes of a Sound Rate Structure” developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of Cascade.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility’s total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the

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concept of SAC, discussed above, into practice and is particularly relevant for Cascade because of the competitive supply alternatives that cap rates under its special contracts.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal—rates should be equal and, where costs are different—rates should be different. In this case, this principle is an important requirement that supports Cascade's proposed use of a single monthly Basic Service Charge for all customers within certain

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of its rate schedules, because delivery costs are identical for its residential customers and for its smallest commercial customers.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

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Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company ("LDC") such as Cascade, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permit proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the

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added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

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A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as LRIC required by the OPUC, or embedded customer, demand, and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and
4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact of modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of

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necessity then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Cascade's proposed revenue increase of $3.62 million to its rate classes.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for each of Cascade's rate classes. Based on this evaluation, adjustments to the present revenue levels in each of Cascade's rate classes were made so that its proposed rates moved class revenues closer to the LRIC of serving each rate class.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Cascade's interclass revenue proposal?

A. Yes. Using Cascade's proposed revenue increase, and the results of its LRIC Study, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with Cascade personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first and benchmark option that I evaluated under Cascade's proposed total revenue level was to adjust the revenue level for each rate class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This

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decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

The second option I considered was assigning the increase in revenues to Cascade's rate classes based on an equal percentage basis of its current base (non-gas) revenues. By definition, this option resulted in each rate class receiving an increase in revenues. However, when this option was evaluated against the LRIC Study results (as measured by changes in the revenue-to-cost ratio for each rate class); there was no movement towards cost for some of Cascade's rate classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provided me with further guidance to develop Cascade's class revenue proposal.

Q. What was the next step in the process?

A. After further discussions with Cascade, I concluded that the appropriate interclass revenue proposal would be one that reflects increases in revenues to certain rate classes, guided by the results of Cascade's LRIC Study, with increases to these rate classes moderated by establishing a maximum increase level (on a percentage basis) above Cascade's proposed overall increase in non-gas revenues of 12.51 percent. This approach established a maximum non-gas revenue increase to any particular rate class of 28.15 percent (2.25 times 12.51 percent). Exhibit CNG/501 presents the derivation of Cascade's proposed class margin revenues by rate schedule on Line 54.

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This preferred revenue allocation approach resulted in reasonable movement of the class revenue-to-cost ratios towards unity or 1.00. That result is reflected in Exhibit CNG/501 on Line 56, wherein the revenue-to-cost ratios are shown to converge towards unity or 1.00 compared to the same measure calculated under current rates. In addition, the amounts of the existing rate subsidies among Cascade's rate classes were reduced for those classes that received increases in revenues. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable.

Q. Have you prepared a comparison of Cascade's present and proposed revenues by rate schedule?

A. Yes. Exhibit CNG/504 presents a comparison of present and proposed revenues for each of Cascade's rate schedules.

VI. SUMMARY OF CASCADE'S RATE DESIGN PROPOSALS

Q. Please summarize the rate design changes Cascade has proposed in this rate proceeding.

A. Cascade has proposed the following rate structure and design changes to its current rate schedules:

- The consolidation of Schedule No. 163, General Distribution Interruptible Transportation Service, and Schedule No. 164, Market Based Distribution Interruptible Transportation Service, into a single Schedule No. 163, while retaining the rate block structure of both schedules.

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- The establishment of a monthly Basic Service Charge for Schedule No. 111, Large Volume General Service, and Schedule No. 170, Interruptible Service, and the renaming of the current Dispatch Service Charge in the consolidated Schedule No.163 as a monthly Basic Service Charge.
- For customers served under Schedule No. 105, General Industrial Service, and Schedule No. 163, Cascade proposes to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service as well as the proposed change in class revenues.

I will present below the specific rate design changes and supporting rationale for certain of Cascade's proposals, and Cascade witness Michael Parvinen will discuss the remaining components of the Company's proposed rate design.

Q, Why is Cascade proposing to consolidate Schedule No. 163 and Schedule No.164?

A. The transportation services provided under the two non-core schedules are virtually indistinguishable from one another. While the rate structure, rate components and charges, and terms and conditions are the same under both schedules, a portion of the Availability section of Rate Schedule No.164 contains language that Cascade finds to be no longer relevant to the service provided. The distinguishing language is reprinted below:

> "…and further provided that customer has a feasible alternative to service under General Distribution System Interruptible Transportation Service Schedule No. 163, such as equal or lower cost alternative fuels, alternative distribution capabilities, or utilization of alternative plant locations outside of the Company's Oregon service area."

In addition, Schedule No.164 has a sixth volumetric rate block that will be included in the new consolidated Schedule No.163.

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Q. Please explain the reasoning behind the establishment of Basic Service Charges for Schedule No. 111 and Schedule No. 170.

A. In the interest of providing improved cost-based price signals to all of its classes of service, Cascade believes that it is appropriate for all service schedules to recover a portion of the customer-related incremental O&M and carrying costs of its incremental meter and service investment in a monthly Basic Service Charge. The LRIC Study provides a guide for this purpose. Line 61 of Exhibit CNG/501 shows the incremental customer-related O&M by class, including meter reading, customer account records and collection, billing and postage and uncollectible expenses. Line 60 of the Exhibit adds the carrying charges on the meter and service investment by class to the incremental O&M. The cost values are stated on a per-month basis. This provides a range of incremental customer-related O&M cost recovery from which to design a monthly Basic Service Charge for each class of service. Cascade is proposing to establish the Basic Service Charge for Schedule No.111 at $125.00 per month, approximately 24% of the upper range of incremental customer-related O&M and meter and service carrying charges for the class. The initial proposed Basic Service Charge for Schedule No.170 was set at $250.00 per month, which collects the entire revenue increase for this class and is approximately 10% of the upper range of incremental customer-related O&M and meter and service carrying charges for the class.

Q. Please describe the changes to the monthly Customer Charge levels for Schedule No. 105 and Schedule No. 163.

A. The proposed monthly Basic Service Charge for Schedule No. 105 is $25.00, approximately 22% of the upper range of the incremental customer-related O&M and meter and service carrying charges for the class, as indicated in the LRIC Study. The renamed

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Basic Service Charge for proposed for Schedule No. 163 is $750.00, which raises the charge to within 50% of the upper range of the indicated incremental customer-related O&M and meter and service carrying charges for the class.

Q. Is Cascade proposing to increase the Basic Service Charge for any of the remaining Schedules?

A. No. Cascade wishes to leave the Basic Service Charges for Schedule No. 101, General Residential Service, and Schedule No. 104, General Commercial Service, at their current $3.00 per month level. At this level, the Basic Service Charge for these two classes of service will recover the monthly customer-related O&M, as indicated by the LRIC Study. Cascade witness Michael Parvinen will discuss this decision further in his testimony.

Q. Have you provided an Exhibit that depicts the proposed rates for all classes of service?

A. Yes. Exhibit CNG/505 shows the derivation of each rate component for each of Cascade's service schedules.

Q. Has a revenue proof been prepared to show that Cascade's proposed rates generate the total distribution revenue and total revenue increase it has proposed in this proceeding (*i.e.* its total non-gas revenue)?

A. Yes. Cascade witness Pam Archer presents Cascade's revenue proof for the Test Year.

VII. CUSTOMER BILL IMPACTS

Q. Please describe the bill impacts for residential customers under Cascade's rate design proposal.

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A. The monthly and annual bill impacts for a typical residential customer using 655 therms per year is shown on Exhibit CNG/506 The average monthly increase for this residential customer under the Company's proposed rate design is $1.88 or 3.48%. Monthly residential bill impacts over a range of usage are depicted on page 1 of Exhibit CNG/507.

Q. Have you prepared bill comparisons for Cascade's other rate classes?

A. Yes. Pages 2 through 7 of Exhibit CNG/507 presents bill comparisons for Cascade's non-residential service schedules at varying monthly levels of gas usage.

Q. Does this conclude your direct testimony?

A. Yes.

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CNG/501
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 501

Summary of LRIC

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	33,745,469	3,944,203	2,790,590	253,388	157,985	3,478,380	276,803	22,844,121
5									
6	O&M Costs								
7	Gas Supply Related								
8	Gas Planning	$ 26,165	$ 11,922	$ 8,191	$ 681	$ 386	$ 640	$ 143	$ 4,201
9	Gas Supply	$ 44,079	$ 17,347	$ 12,273	$ 1,114	$ 695	$ 1,511	$ 1,217	$ 9,922
10	Gas Control	$ 95,077	$ 37,043	$ 26,208	$ 2,380	$ 1,484	$ 12,058	$ 2,600	$ 13,305
11	Customer Related								
12	Meter Reading	$ 253,003	$ 211,393	$ 35,101	$ 396	$ 1,499	$ 3,691	$ 461	$ 461
13	Customer Acoount records and collec	$ 1,229,953	$ 1,048,824	$ 174,154	$ 1,964	$ 230	$ 3,825	$ 478	$ 478
14	Billing Postage & Printing	$ 346,211	$ 296,208	$ 49,184	$ 555	$ 65	$ 160	$ 20	$ 20
15	Uncollectible	$ 278,894	$ 226,650	$ 52,214	$ 30	$ -	$ -	$ -	$ -
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								
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	$ 11,632,431	$ 4,526,025	$ 1,085,696	$ 921,423	$ 241,753	$ 2,758,597	$ 382,489	$ 1,716,447
22	Subtotal: Customer Investment Costs	$ 27,516,224	$ 16,353,156	$ 4,150,736	$ 1,069,050	$ 321,645	$ 3,287,183	$ 507,676	$ 1,826,778
23									
24	System Core Main Carrying Costs								
25	Capacity	$ 37,706,253	$ 21,302,440	$ 14,546,501	$ 1,186,418	$ 655,982	$ -	$ -	$ 14,912
26	Commodity	$ 12,881,733	$ 4,660,723	$ 3,297,540	$ 299,420	$ 186,685	$ 4,110,277	$ 327,088	$ -
27	Subtotal: System Core Main Costs	$ 50,587,986	$ 25,963,163	$ 17,844,041	$ 1,485,838	$ 842,667	$ 4,110,277	$ 327,088	$ 14,912
28									
29	LRIC - Distribution	$ 80,377,591	$ 44,165,705	$ 22,352,103	$ 2,562,007	$ 1,168,671	$ 7,419,344	$ 839,684	$ 1,870,077

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
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	$ 27,516,224	$ 16,353,156	$ 4,150,736	$ 1,069,050	$ 321,645	$ 3,287,183	$ 507,676	$ 1,826,778
35	Sysctem Core Mains	$ 50,587,986	$ 25,963,163	$ 17,844,041	$ 1,485,838	$ 842,667	$ 4,110,277	$ 327,088	$ 14,912
36	Total	$ 80,377,591	$ 44,165,705	$ 22,352,103	$ 2,562,007	$ 1,168,671	$ 7,419,344	$ 839,684	$ 1,870,077
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	$ 17,900,283	$ 9,059,268	$ 1,038,377	$ 473,660	$ 3,007,047	$ 340,323	$ 757,939
41	Revenue to Cost Ratio		0.91	0.83	0.46	0.49	0.76	1.00	2.36
42									
43	Incremental Non-gas Revenue Req.	$ 3,622,770	$ 1,587,420	$ 1,545,822	$ 565,493	$ 242,734	$ 711,185	$ (394)	$ (1,029,490)
44									
45	Step 1								
46	Increase relative to system average			1.50	2.25	2.25	2.25	0.25	-
47	Percent Increase	12.51%		18.77%	28.15%	28.15%	28.15%	3.13%	0.00%
48	Increase Step 1	$ 2,265,267		$ 1,410,135	$ 133,127	$ 65,011	$ 646,336	$ 10,658	$ -
49									
50	Step 2								
51	Increase Step 2	$ 1,357,503	$ 1,357,503	$ -	$ -	$ -	$ -	$ -	$ -
52									
53	Total Increase	$ 3,622,770	$ 1,357,503	$ 1,410,135	$ 133,127	$ 65,011	$ 646,336	$ 10,658	$ -
54	Margin after Increase	$ 32,576,897	$ 17,670,366	$ 8,923,581	$ 606,011	$ 295,937	$ 2,942,198	$ 351,375	$ 1,787,429
55	Percent Increase		8.32%	18.77%	28.15%	28.15%	28.15%	3.13%	0.00%
56	Revenue to Cost Ratio		0.99	0.99	0.58	0.62	0.98	1.03	2.36
57	Final Increase relative to system average		0.67	1.50	2.25	2.25	2.25	0.25	0.00
58									
59	LRIC Supported Customer Cost per month								
60	Cust O&M Plus Meter & Service Carrying Charge		$ 19.14	$ 28.59	$ 113.11	$ 523.63	$ 1,396.52	$ 2,628.06	$ 2,318.54
61	Cust O&M		$ 2.51	$ 2.63	$ 2.21	$ 11.50	$ 19.99	$ 19.99	$ 19.99

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 501 Attachment A

Ronald J. Amen Qualification

Ronald J. Amen

Mr. Amen has over thirty-five years of combined experience in utility management and consulting in the areas of regulatory affairs, resource planning, organizational development, distribution operations and customer service, marketing and sales, and systems administration. He has particular expertise in the following areas: regulatory policy, strategy and analysis; resource strategy, planning and financial analysis; cost allocation and pricing issues; business process design and organizational structures; and expert witness testimony. Prior to joining Black & Veatch, Mr. Amen's consulting experience included Concentric Energy Advisors, Inc. and Navigant Consulting, Inc. His prior utility experience includes Manager of Federal Regulatory Affairs at Puget Sound Energy, Inc., Director of Rates at Washington Natural Gas Company, Regional Director - Operations and Director – Rates for Indiana Energy (now Vectren), and management positions in Information Systems and Distribution Operations at Ohio Valley Gas Corporation.

DIRECTOR

Specialization:
Financial, regulatory, strategic, operations and litigation support

Office Location
Redmond, WA

Education
- B.S., Business Administration (Finance and Economics), College of Business Administration, University of Nebraska, 1978

Professional Associations
- American Gas Association
- Southern Gas Association

Year Career Started
1978

Year Started with B&V
2013

PROJECT EXPERIENCE

REGULATORY POLICY, STRATEGY AND ANALYSIS

Southwestern Electric/Gas Utility |

Provided case management, revenue requirement, cost of service and rate design support for a general rate cases in the utility's two State regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal-fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential Energy Company |

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Confidential Energy Company |

Provided regulatory due diligence support for client related to a proposed merger with a multi-jurisdictional gas/electric company, including an evaluation of the regulatory landscape in the various applicable State jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential Energy Company |

Performed due diligence on behalf of a confidential energy company client related to the acquisition of a U.S. interstate pipeline, involving a market assessment related to its customer contracts and their prospective alternatives.

Eastern Electric/Gas Utility |

Provided management with an evaluation of its line extension practices for both its gas and electric services and an earnings impact assessment using a proprietary evaluation model. Conducted a workshop for management on the results of the evaluation and recommendations for consideration in the areas of revenue enhancements, modification of internal policies and procedures and construction cost control areas.

Eastern Gas Utility |

Provided management with an evaluation of the policies, procedures and tools presently used in its new customer addition process, an assessment of the impact of new customer growth on NOI, and regulatory solutions to accelerate recovery of new customer costs that best meet the regulatory requirements of its three state jurisdictions.

Canadian Gas Utility |

Engaged to assist with the development of a Gas Transmission asset ownership strategy. The project included researching examples from other jurisdictions in North America for transmission ownership structures, the supporting rationale, and the resulting regulatory treatment.

Eastern Gas Utility |

Provided expert witness testimony on the subject of new area expansion programs in the U.S. for the client's general rate case proceeding. As part of a negotiated settlement of the case, the client was permitted to establish a new area expansion pilot program.

Pacific Northwest Electric/Gas Utility |

Redesigned gas line extension policy based on financial investment criteria, standardized construction costs, and revenue contributions derived from the client's residential end-use data (building type/size/vintage, appliance type, etc.). Introduced a new customer rate option for customers whose facilities extensions did not meet the target rate of return requirement, which significantly reduced earnings attrition caused by rapid customer growth. In a later general rate proceeding, testimony support was provided regarding the modifications and revisions to the facilities extension program.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Western Canadian Gas Utility |

Retained to help develop a gas supply incentive mechanism in cooperation with the BCUC staff and the Company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.

Western Electric Utility |

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission, and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the PPA, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced bi-weekly confidential reports to the commission regarding the process and its results.

Pacific Northwest Gas Utility |

Assisted with the development of its long-term Integrated Resource Plan ("IRP") for its Oregon and Washington service territories. The IRP includes the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Pacific Northwest Electric/Gas Utility |

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Pacific Northwest Electric/Gas Utility |

As part of a review of a gas procurement strategy and hedging analytics, provided gas LDC case studies for gas procurement and risk management practices, including identification of risk management best practices across the industry.

Pacific Northwest Electric/Gas Utility |

Provided resource planning strategy and analysis for the Company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts.

Pacific Northwest Electric/Gas Utility |

Engaged as a member of a consulting team serving as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multi-track solicitation process for and evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition in a subsequent power cost rate proceeding.

Midwestern Electric/Gas Utility |

Provided an evaluation of the functions provided by the utility's underground storage facilities for the purpose of assigning cost responsibility to the various customer groups, which had been challenged by parties in the company's general rate proceeding.

Southwestern Electric/Gas Utility |

Conducted an evaluation of two gas operating subsidiaries, their capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.

Midwestern Municipal Electric Utility |

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process.

European Electric Utility |

Provided strategy and analysis support, including a review of the natural gas value chain in the U.S., as part of an overall project scope focusing on the evaluation of retail multi-energy strategies for the client.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Southwestern Electric Utility |

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the U.S. Southwest. Analyzed 2009-2011 residential data to determine what sort of conservation effect the Company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use ("TOU") rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Northeastern Electric Utility |

Supported utility in its decoupling proposal for the Company's general rate case. Work included: (1) research on the financial implications of decoupling; (2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; (3) identification of rate adjustment mechanisms that would work together with the Company's proposed decoupling mechanism; and (4) preparing pre-filed testimony and testifying at hearings in support of the Company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Northeastern Electric/Gas Utility |

Conducted class allocated cost of service studies for the client's New England natural gas operations. This included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Midwestern Energy Company |

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in three general rate cases before the Indiana Utility Regulatory Commission.

Midwestern Electric Utility |

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric operations. Work included reconfiguring the Company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a Fixed/Variable study for Production costs, and a Primary – Secondary study for poles, transformers and conductors. Performed a Time of Use analysis to determine the appropriate rate differentials for its Peak and Off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

Midwestern Gas Utility |

Provided cost of service and rate design support for the Company's general rate case filings in its two State jurisdictions and in support of a Section 311 transportation filing before the Federal Energy Regulatory Commission (FERC). Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment (WNA) mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the Company's largest customer classes. Conducted a pre-filing "Decoupling" workshop for the utility commission staff.

Pacific Northwest Gas Utility |

Provided Cost of Service and Rate Design support for the utility's general rate case, including expert witness testimony. Assisted the client with an earlier revenue neutral reconfiguration of its Commercial / Industrial sales and transportation service offerings. The earlier initiative included collaborative work with an industrial customer stakeholder group.

Midwestern Energy Company |

Assisted the client with the pursuit of alternative regulatory initiatives in conjunction with company's expansion of its energy efficiency and conservation programs. Supported the research, design, and selection of Revenue Decoupling mechanisms for its two regulated gas utility subsidiaries. Served as the cost of service witness in two general rate case filings.

Pacific Northwest Electric/Gas Utility |

In two general rate proceedings, provided Cost of Service and Rate Design support, including expert witness testimony in support of the utility's proposed gas Revenue Decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for Infrastructure Replacement, Electric Power Cost Adjustment mechanisms and Gas Supply Pricing Options of utilities in North America.

U.S. Energy Company |

Engagement director for Cost of Service and Rate Design support for the general rate proceedings of the Company's Midwestern and Northeastern gas utilities, including expert witness testimony on cost of service, rate design and declining use-per-customer. Rate design support included a proposed ten-year weather normal, and the introduction of straight-fixed variable rates (Midwestern LDC). This was the third consecutive rate case engagement for the Northeastern LDC.

Midwestern Electric/Gas Utility |

Assisted the Company with the preparation of a retail customer choice filing for one of its gas distribution jurisdictions. Provided support for the development ancillary service costs, the design of program cost recovery mechanisms, and tariff structure for service offerings.

Western Canadian Gas Utility |

Served as engagement manager for cost of service and rate design support. Represented the client in its capital investment recovery proceeding for a major pipeline project, a cross-provincial transmission pipeline. The three-phase project included regulatory strategy support for executive management regarding the integration of the pipeline proposal with the utility's PBR and unbundling initiatives and a global rate design proceeding. Cost of service support included a review of its gas cost portfolio allocation to firm sales customer classes, a survey of the trends in gas cost allocations and incentive mechanisms in North America, and serving as a facilitator for an all-party cost allocation and rate design workshop.

Northeastern Gas Utility |

Served as engagement manager for cost of service and rate design support, including expert witness testimony, for the client's participation in a state-wide gas unbundling proceeding. Subsequent projects included analysis of the client's demand forecasting capability, implementation of an algorithm-based balancing service and a cost of service studies related to transportation related administrative costs, resources supporting system reliability and recovery of potentially stranded costs.

Midwestern Gas Transmission/Distribution Utility |

Engagement manager for cost of service and rate design support, including expert witness testimony, for client's asset separation and unbundling proceeding as well as a subsequent general rate case. Integrated gas utility (wellhead to burner-tip) unbundled upstream services (production and gathering, storage, and intra-state transmission) from its distribution business.

South American Gas Utility |

For an affiliate of a major U.S. energy company, conducted a cost of service and rate design training for management personnel engaged in the planned restructuring of the rate-setting processes for three gas utilities in Brazil.

Canadian Energy Marketer |

Provided consulting support and position paper on cost allocation and pricing issues for Canadian gas marketer's participation in a restructuring collaborative sponsored by the intra-provincial pipeline and local distribution utility in Saskatchewan.

Pacific Northwest Gas Utility |

Negotiated and obtained regulatory approval of a 20-year contract with the company's largest industrial customer, which avoided bypass of 14 primary plant facilities within the service territory, prevented loss of annual throughput, and maintained contribution to system costs.

Pacific Northwest Gas Utility |

Obtained regulatory approval of unbundled, cost-based transportation services to meet large commercial and industrial customer needs and re-designed rates of other classes to better align with new cost of service methodology. The project required the facilitation of a collaborative working group of key industrial customers, customer associations, commission staff, and consumer advocacy agencies.

Western Energy Company |

Provided case strategy and cost of service support for the biennial cost allocation proceedings of two utility subsidiaries of the Company.

UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Pacific Northwest Electric/Gas Utility |

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards; evaluate existing PM processes along with newly introduced corporate CSA processes; and propose PM and corporate process and documentation efficiencies. This was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Pacific Northwest Electric/Gas Utility |

Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("New Business Investment") and the management policies and practices that influence the new business capital investment. Examined the inter-relationships of our client's management policies and practices in the functional areas related to New Business Investment and developed an understanding of the nature of the costs captured by the New Business Investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or inter-relationships between management policies and practices, as well as other exogenous factors, and the resulting impact on New Business Investment.

Pacific Northwest Electric/Gas Utility |

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "Best Practices," from other electric utilities and other relevant transmission entities.

Midwestern Energy Company |

Provided audit support for one of the Company's gas and electric utilities during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning process to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing Company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Midwestern Energy Company |

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas utilities, electric utilities, and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

Western Multi-state Water Utility |

Engaged to manage the implementation of a new revenue decoupling mechanism into its 24 separate rate areas. Changes to the following processes and related procedures were required: rate setting, meter reading, billing, revenue and financial reporting. Microsoft Project was used to manage and track the implementation throughout the following organizations: Rates, Accounting, Information systems, Communications, and Customer Service.

Northwestern Electric/Gas Utility |

Conducted an evaluation of the Company's key accounts (Top 100) and business account services organization. Work included compilation of "best practices" from peer group utilities, recommendations related to staffing levels, roles and responsibilities, and the interrelationships with the customer service (call center), revenue management and community relations organizations of the utility.

Eastern Gas Utility |

Provided market monitoring strategies and action plans based on an analysis of competitive threats and discussions with the client's customers and other utilities facing similar issues. Intent of recommended monitoring strategies and corresponding action plans to result in increased customer growth (meters) and/or customer retention, including a prioritized implementation approach to the monitoring strategies and action plans, based on benefits to the client and time to implement.

Southern Electric/Gas Utility |

Conducted an evaluation of two gas operating subsidiaries, their capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.

Midwestern Municipal Electric Utility |

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process, which involved establishing the organization structure, span of control, job descriptions, qualifications, and salary ranges. We worked closely with the head of new organization, the municipal utility management, and the relevant municipal government agencies; and facilitated numerous management and stakeholder meetings.

Midwestern Electric/Gas Utility |

Provided research and consulting support to establish performance metrics and benchmarks from peer group companies for the client's performance management system.

Midwestern Energy Company |

For a Midwestern energy company, Mr. Amen was responsible for marketing, customer service, gas distribution system construction, operation and maintenance, for a regional operating service territory of the company's gas utility. Among other gas operations responsibilities, Mr. Amen managed a field sales force responsible for sales plan development, including market analysis, program design, and cost-effectiveness evaluations for the following customer segments and/or trade alley groups: residential home builders and commercial developers; HVAC contractors; large commercial and industrial key accounts; public institutions; and governmental facilities.

Business Process Redesign and Organizational Restructuring – While serving in the aforementioned utility management capacity as Regional Director, Mr. Amen managed the successful integration of an acquired gas utility company into a regional operation.

Re-engineering Operations – Mr. Amen was a member of a management team that restructured the company's field organization into six regional operations (reduced from 26 district offices) resulting in a streamlined organization, which provided enhanced customer service while substantially reducing operating costs. The nine core management team members facilitated the work of over forty individual study groups during the eighteen-month transition period. This same management team redesigned the capital budgeting process and established new standards governing the use of construction contractors.

EXPERT WITNESS TESTIMONY PRESENTATION

- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

PROFESSIONAL HISTORY

Black & Veatch Corporation (Present)
Director

Concentric Energy Advisors, Inc. (2007 – 2013)
Vice President

Navigant Consulting, Inc. (1997 – 2007)
Director

Puget Sound Energy, Inc. (1997)
Manager – Federal Regulatory Affairs

Washington Natural Gas Company (1993 – 1997)
(merged with Puget Power and Light to form Puget Sound Energy in 1997)
Director – Rates and Tariffs

Indiana Energy (now Vectren) (1984 – 1993)
Regional Director – Distribution Operations
Director – Rates

Ohio Valley Gas Corporation (1978 – 1984)
Data Processing Manager
Assistant District Manager – Distribution Operations

SELECTED PUBLICATIONS/PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

CNG/502
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 502

Incremental Plant Carrying Costs

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		58.95	85.16	899.14				
27	2013 Average cost per ft	$/ft		$ 7.69	$ 7.69	$ 54.83				
28	Customer mains investment per customer	$		$ 453	$ 655	$ 49,297				
29	Customer Mains Investment by Class		$ 69,037,393	$ 26,861,539	$ 6,443,506	$ 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										
35	C. Commodity (Safety) Related									
36	Incr. mains commodity investment/therm	$	$ 4,115,887	$ 1,489,164	$ 1,053,608	$ 95,669	$ 59,648	$ 1,313,289	$ 104,509	
37	Safety Related Investment per customer	$		$ 25.13	$ 107.09	$ 862.42	$ 4,588.33	$ 41,040.27	$ 26,127.29	$ -
38										

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
39	Long-Run System Replacement Investment									
40	Mains System Replacement Cost	$	$ 369,272,368							
41	Less: Customer Mains Investment	$	$ (73,560,770)							
42	Long-Run System Replacement Investment	$	$ 295,711,598							
43										
44	Capacity	%	76%							
45	Investment per Peak Day Capacity	$/Dth-Day	$ 2,687							
46	Investment by Class	$	$ 223,375,604	$ 126,247,708	$ 86,209,017	$ 7,031,238	$ 3,887,641	$ -	$ -	$ -
47	Investment per customer	$		$ 2,131	$ 8,762	$ 63,384	$ 299,049	$ -	$ -	$ -
48										
49	Commodity	%	24%							
50	System Replacement Investment per Dth	$/Dth	$ 6.64							
51	Investment by Class	$	$ 72,335,995	$ 26,171,793	$ 18,516,984	$ 1,681,360	$ 1,048,308	$ 23,080,820	$ 1,836,730	
52	Investment per customer	$		$ 442	$ 1,882	$ 15,157	$ 80,639	$ 721,276	$ 459,183	$ -
53										
54	Total mains investment by class	$	$ 369,272,368	$ 180,950,490	$ 112,346,225	$ 14,286,870	$ 6,435,931	$ 40,766,123	$ 4,211,274	$ 10,275,455
55	Economic Carryin Charge Rate			16.85%	16.85%	16.85%	16.85%	16.85%	16.85%	16.85%
56	Class Annual Carrying Charge	$	$ 62,220,417	$ 30,489,189	$ 18,929,737	$ 2,407,261	$ 1,084,420	$ 6,868,873	$ 709,577	$ 1,731,359
57										
58	**Total Carrying Costs**		**$ 78,104,209**	**$ 42,316,319**	**$ 21,994,777**	**$ 2,554,887**	**$ 1,164,312**	**$ 7,397,459**	**$ 834,764**	**$ 1,841,689**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 503

Incremental O&M Costs

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
O&M Costs

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	-	-	-
3	Customer Count	69,254	59,252	9,839	111	13	32	4	4
4	Throughput	33,745,469	3,944,203	2,790,590	253,388	157,985	3,478,380	276,803	22,844,121
5	Sales	7,422,969	3,944,203	2,790,590	253,388	157,985		276,803	
6									
7	Peak & Average	100%	34%	23%	2%	1%	5%	0%	34%
8									
9	Customer Count (Small Customers)	69,201	59,252	9,839	111				
10	Customer Count (Large Customers)	53				13	32	4	4
11									
12	Volumes (Core)		3,944,203	2,790,590	253,388	157,985		276,803	
13	Volumes (Non-core)						3,478,380		22,844,121
14									
15	**Gas Planning**								
16	Core	$ 21,324	$ 11,922	$ 8,191	$ 681	$ 386		$ 143	
17	Non-core	$ 4,840					$ 640		$ 4,201
18	Total Core + Non-core	$ 26,165	$ 11,922	$ 8,191	$ 681	$ 386	$ 640	$ 143	$ 4,201
19	Cost per customer		$ 0.20	$ 0.83	$ 6.14	$ 29.70	$ 19.99	$ 35.84	$ 1,050.20
20									
21	**Gas Supply**								
22	Core	$ 32,646	$ 17,347	$ 12,273	$ 1,114	$ 695		$ 1,217	
23	Non-core	$ 11,433					$ 1,511		$ 9,922
24	Total Core + Non-core	$ 44,079	$ 17,347	$ 12,273	$ 1,114	$ 695	$ 1,511	$ 1,217	$ 9,922
25	Cost per Cust		$ 0.29	$ 1.25	$ 10.05	$ 53.45	$ 47.21	$ 304.34	$ 2,480.56
26									
27	**Gas Control**								
28	Core	$ 69,714	$ 37,043	$ 26,208	$ 2,380	$ 1,484		$ 2,600	
29	Non-core	$ 25,363					$ 12,058		$ 13,305
30	Total Core + Non-core	$ 95,077	$ 37,043	$ 26,208	$ 2,380	$ 1,484	$ 12,058	$ 2,600	$ 13,305
31	Cost per Cust		$ 0.63	$ 2.66	$ 21.45	$ 114.13	$ 376.81	$ 649.91	$ 3,326.30
32									
33	**Total Gas Supply O&M**	**$ 165,321**	**$ 66,311**	**$ 46,673**	**$ 4,176**	**$ 2,565**	**$ 14,208**	**$ 3,960**	**$ 27,428**

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
O&M Costs

Line #	Description	Total	101	104	105	111	163+164	170	900
			Residential	Commercial	Industrial	Large Volume	General		Special
			Service	Service	Service	Service	Distribution	Interruptible	Contracts
			core	core	core	core	non-core	core	non-core
34									
35	**Meter Reading**								
36	Meter Reading Expense (Res + Small C	$ 246,890	$ 211,393	$ 35,101	$ 396	$ -	$ -	$ -	$ -
37	Meter Reading Expense (Industrial)	$ 6,113	$ -	$ -	$ -	$ 1,499	$ 3,691	$ 461	$ 461
38	Meter Reading Expense	$ 253,003	$ 211,393	$ 35,101	$ 396	$ 1,499	$ 3,691	$ 461	$ 461
39	Cost per customer		$ 3.57	$ 3.57	$ 3.57	$ 115.34	$ 115.34	$ 115.34	$ 115.34
40									
41	**Customer Acoount records and collection**								
42	Expense	$ 1,225,172	$ 1,048,824	$ 174,154	$ 1,964	$ 230			
43	Expense - Manual Billing	$ 4,782					$ 3,825	$ 478	$ 478
44	Cost per customer		$ 17.70	$ 17.70	$ 17.70	$ 17.70	$ 119.54	$ 119.54	$ 119.54
45									
46	**Billing Postage & Printing**								
47	Expense	$ 346,211	$ 296,208	$ 49,184	$ 555	$ 65	$ 160	$ 20	$ 20
48	Cost per customer		$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
49									
50	**Uncollectible**								
51	COMMERCIAL	$ 52,214		$ 52,214					
52	INDUSTRIAL	$ 30			$ 30				
53	RESIDENTIAL	$ 226,650	$ 226,650						
54	Total OR	$ 278,894	$ 226,650	$ 52,214	$ 30	$ -	$ -	$ -	$ -
55	Cost per customer		$ 3.83	$ 5.31	$ 0.27	$ -	$ -	$ -	$ -
56									
57	**Total Customer O&M**	**$ 2,108,061**	**$ 1,783,074**	**$ 310,653**	**$ 2,944**	**$ 1,795**	**$ 7,676**	**$ 960**	**$ 960**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 504

Summary of Revenue by Rate Class

Summary of Revenue by Rate Class
Present and Proposed Rates

Customer Class	Revenues			
	Pro Forma	**Proposed**	**$ Difference**	**% Difference**
Residential - 101				
Basic Service Charge	$ 2,133,060	$ 2,133,060	$ 0	0%
Delivery Charge	$ 14,179,803	15,537,398	1,357,595	10%
Total 101 Revenue	$ 16,312,863	$ 17,670,458	$ 1,357,595	8%
Commercial - 104				
Basic Service Charge	$ 354,188	$ 354,188	$ 0	0%
Delivery Charge	$ 7,159,258	8,569,343	1,410,085	20%
Total 104 Revenue	$ 7,513,446	$ 8,923,531	$ 1,410,085	19%
Industrial - 105				
Basic Service Charge	$ 15,974	$ 33,279	$ 17,305	108%
Delivery Charge	$ 456,910	572,734	115,824	25%
Total 105 Revenue	$ 472,884	$ 606,013	$ 133,129	28%
Large Volume - 111				
Basic Service Charge	$ -	$ 19,500	$ 19,500	
Delivery Charge	$ 230,926	276,441	45,515	20%
Total 111 Revenue	$ 230,926	$ 295,941	$ 65,015	28%
General Distribution - 163				
Basic Service Charge	$ 174,000	$ 261,000	$ 87,000	50%
Delivery Charge	$ 1,441,569	1,818,093	376,524	26%
Total 163 Revenue	$ 1,615,569	$ 2,079,093	$ 463,524	29%
Market Based Distribution - 164				
Basic Service Charge	$ 18,000	$ 27,000	$ 9,000	50%
Delivery Charge	$ 662,293	836,227	173,935	26%
Total 164 Revenue	$ 680,293	$ 863,227	$ 182,935	27%
Interruptible - 170				
Basic Service Charge	$ -	$ 12,000	$ 12,000	
Delivery Charge	$ 340,717	339,388	(1,329)	0%
Total 170 Revenue	$ 340,717	$ 351,388	$ 10,671	3%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 505

Analysis of Revenue by Detailed Rate Schedule

Customer Class	Pro Forma Test Year Revenues			Proposed Revenues		Difference	
	Billing Units	Present Rate	Revenue	Proposed Rates	Revenue	$ Amount	% Amount
Residential - 101							
Basic Service Charge	711,020	$3.00	$ 2,133,060	$3.00	$ 2,133,060	$ 0	0%
Delivery Charge	39,442,028	$0.35951	$ 14,179,803	$0.39393	$ 15,537,398	$ 1,357,595	10%
Total 101 Revenue			**$ 16,312,863**		**$ 17,670,458**	**$ 1,357,595**	8%
Commercial - 104							
Basic Service Charge	118,063	$3.00	$ 354,188	$3.00	$ 354,188	$ 0	0%
Delivery Charge	27,905,898	$0.25655	$ 7,159,258	$0.30708	$ 8,569,343	$ 1,410,085	20%
Total 104 Revenue			**$ 7,513,446**		**$ 8,923,531**	**$ 1,410,085**	19%
Industrial - 105							
Basic Service Charge	1,331	$12.00	$ 15,974	$25.00	$ 33,279	$ 17,305	108%
Delivery Charge	2,533,883	$0.18032	$ 456,910	$0.22603	$ 572,734	$ 115,824	25%
Total 105 Revenue			**$ 472,884**		**$ 606,013**	**$ 133,129**	28%
Large Volume - 111							
Basic Service Charge	156	$0.00	$ -	$125.00	$ 19,500	$ 19,500	
Delivery Charge	1,579,845	$0.14617	$ 230,926	$0.17498	$ 276,441	$ 45,515	20%
Total 111 Revenue			**$ 230,926**		**$ 295,941**	**$ 65,015**	28%
General Distribution - 163							
Basic Service Charge	348	$500.00	$ 174,000	$750.00	$ 261,000	$ 87,000	50%
Delivery Charge - first 10,000 therms	2,965,270	$0.12424	$ 368,405	$0.15686	$ 465,132	$ 96,727	26%
Delivery Charge - next 10,000 therms	2,250,498	$0.11210	$ 252,281	$0.14153	$ 318,513	$ 66,232	26%
Delivery Charge - next 30,000 therms	3,465,663	$0.10534	$ 365,073	$0.13300	$ 460,933	$ 95,860	26%
Delivery Charge - next 50,000 therms	2,698,995	$0.06478	$ 174,841	$0.08179	$ 220,751	$ 45,910	26%
Delivery Charge - next 400,000 therms	8,417,447	$0.03297	$ 277,523	$0.04163	$ 350,418	$ 72,895	26%
Delivery Charge - over 500,000 therms	104,524	$0.03297	$ 3,446	$0.02244	$ 2,346	$ (1,101)	-32%
Total 163 Revenue			**$ 1,615,569**		**$ 2,079,093**	**$ 463,524**	29%
Market Based Distribution - 164							
Basic Service Charge	36	$500.00	$ 18,000	$750.00	$ 27,000	$ 9,000	50%
Delivery Charge - first 10,000 therms	360,000	$0.12424	$ 44,726	$0.15686	$ 56,470	$ 11,743	26%
Delivery Charge - next 10,000 therms	360,000	$0.11210	$ 40,356	$0.14153	$ 50,951	$ 10,595	26%
Delivery Charge - next 30,000 therms	1,080,000	$0.10534	$ 113,767	$0.13300	$ 143,640	$ 29,873	26%
Delivery Charge - next 50,000 therms	1,800,000	$0.06478	$ 116,604	$0.08179	$ 147,222	$ 30,618	26%
Delivery Charge - next 400,000 therms	9,629,514	$0.03297	$ 317,485	$0.04163	$ 400,877	$ 83,392	26%
Delivery Charge - over 500,000 therms	1,651,887	$0.01777	$ 29,354	$0.02244	$ 37,068	$ 7,714	26%
Total 164 Revenue			**$ 680,293**		**$ 863,227**	**$ 182,935**	27%
Interruptible - 170							
Basic Service Charge	48	$0.00	$ -	$250.00	$ 12,000	$ 12,000	
Delivery Charge	2,768,032	$0.12309	$ 340,717	$0.12261	$ 339,388	$ (1,329)	0%
Total 170 Revenue			**$ 340,717**		**$ 351,388**	**$ 10,671**	3%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 506

Residential Impact by Month

Residential - 101

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
1	Basic Service Charge		$3.00	$3.00		
2	Delivery Charge		$0.35951	$0.39393		
3	PGA Rate		$0.57535	$0.57535		

	Month	Average therms per Customer	Revenue at Present Rates	Revenue at Proposed Rates	Monthly Bill Change Amount	Monthly Bill Change Percent
4	January	117	$ 112.38	$ 116.41	$ 4.03	3.58%
5	February	107	$ 103.03	$ 106.71	$ 3.68	3.57%
6	March	90	$ 87.14	$ 90.24	$ 3.10	3.56%
7	April	64	$ 62.83	$ 65.03	$ 2.20	3.51%
8	May	40	$ 40.39	$ 41.77	$ 1.38	3.41%
9	June	25	$ 26.37	$ 27.23	$ 0.86	3.26%
10	July	18	$ 19.83	$ 20.45	$ 0.62	3.12%
11	August	14	$ 16.09	$ 16.57	$ 0.48	3.00%
12	September	15	$ 17.02	$ 17.54	$ 0.52	3.03%
13	October	23	$ 24.50	$ 25.29	$ 0.79	3.23%
14	November	41	$ 41.33	$ 42.74	$ 1.41	3.41%
15	December	101	$ 97.42	$ 100.90	$ 3.48	3.57%
16	Total	655	$ 648.33	$ 670.88	$ 22.55	
17	Monthly Average		$ 54.03	$ 55.91	$ 1.88	3.48%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

RONALD J. AMEN
Exhibit No. 507

Impact of Recommended Rate Changes

Residential - 101

Line No.	(a)	(b)	(c)	(d)	(e)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$3.00	$3.00		
2	Delivery Charge	$0.35951	$0.39393		
3	PGA Rate	$0.57535	$0.57535		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$3.00	$3.00	$0.00	0.00%
5	25	$26.37	$27.23	$0.86	3.26%
6	30	$31.05	$32.08	$1.03	3.33%
7	35	$35.72	$36.92	$1.20	3.37%
8	40	$40.39	$41.77	$1.38	3.41%
9	45	$45.07	$46.62	$1.55	3.44%
10	50	$49.74	$51.46	$1.72	3.46%
11	60	$59.09	$61.16	$2.07	3.49%
12	70	$68.44	$70.85	$2.41	3.52%
13	80	$77.79	$80.54	$2.75	3.54%
14	90	$87.14	$90.24	$3.10	3.56%
15	100	$96.49	$99.93	$3.44	3.57%
16	110	$105.83	$109.62	$3.79	3.58%
17	120	$115.18	$119.31	$4.13	3.59%
18	130	$124.53	$129.01	$4.47	3.59%
19	140	$133.88	$138.70	$4.82	3.60%
20	150	$143.23	$148.39	$5.16	3.60%
21	160	$152.58	$158.08	$5.51	3.61%
22	170	$161.93	$167.78	$5.85	3.61%
23	180	$171.27	$177.47	$6.20	3.62%
24	190	$180.62	$187.16	$6.54	3.62%
25	200	$189.97	$196.86	$6.88	3.62%
26	210	$199.32	$206.55	$7.23	3.63%
27	220	$208.67	$216.24	$7.57	3.63%
28	230	$218.02	$225.93	$7.92	3.63%
29	240	$227.37	$235.63	$8.26	3.63%
30	250	$236.72	$245.32	$8.61	3.64%

Commercial - 104

Line No.	(a)	(b) Present Rates	(d) Proposed Rates	(e)	(f)
1	Basic Service Charge	$3.00	$3.00		
2	Delivery Charge	$0.25655	$0.30708		
3	PGA Rate	$0.57535	$0.57535		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$3.00	$3.00	$0.00	0.00%
5	50	$44.60	$47.12	$2.53	5.67%
6	60	$52.91	$55.95	$3.03	5.73%
7	70	$61.23	$64.77	$3.54	5.78%
8	80	$69.55	$73.59	$4.04	5.81%
9	90	$77.87	$82.42	$4.55	5.84%
10	100	$86.19	$91.24	$5.05	5.86%
11	110	$94.51	$100.07	$5.56	5.88%
12	120	$102.83	$108.89	$6.06	5.90%
13	130	$111.15	$117.72	$6.57	5.91%
14	140	$119.47	$126.54	$7.07	5.92%
15	150	$127.79	$135.36	$7.58	5.93%
16	160	$136.10	$144.19	$8.08	5.94%
17	170	$144.42	$153.01	$8.59	5.95%
18	180	$152.74	$161.84	$9.10	5.95%
19	190	$161.06	$170.66	$9.60	5.96%
20	200	$169.38	$179.49	$10.11	5.97%
21	250	$210.98	$223.61	$12.63	5.99%
22	300	$252.57	$267.73	$15.16	6.00%
23	350	$294.17	$311.85	$17.69	6.01%
24	400	$335.76	$355.97	$20.21	6.02%
25	450	$377.36	$400.09	$22.74	6.03%
26	500	$418.95	$444.22	$25.27	6.03%
27	600	$502.14	$532.46	$30.32	6.04%
28	700	$585.33	$620.70	$35.37	6.04%
29	800	$668.52	$708.94	$40.42	6.05%
30	1,000	$834.90	$885.43	$50.53	6.05%
31	1,250	$1,042.88	$1,106.04	$63.16	6.06%
32	1,500	$1,250.85	$1,326.65	$75.79	6.06%
33	1,750	$1,458.83	$1,547.25	$88.43	6.06%
34	2,000	$1,666.80	$1,767.86	$101.06	6.06%
35	2,500	$2,082.75	$2,209.08	$126.33	6.07%
36	3,000	$2,498.70	$2,650.29	$151.59	6.07%
37	3,500	$2,914.65	$3,091.51	$176.86	6.07%
38	4,000	$3,330.60	$3,532.72	$202.12	6.07%

Industrial - 105

Line No.	(a)	(b)	(d)
		Present Rates	Proposed Rates
1	Basic Service Charge	$12.00	$25.00
2	Delivery Charge	$0.18032	$0.22603
3	PGA Rate	$0.57535	$0.57535

Line No.	(a) Monthly Consumption (therms)	(b) Revenue at Present Rates	(d) Revenue at Proposed Rates	(e) Revenue Change Amount	(f) Revenue Change Percent
4	0	$12.00	$25.00	$13.00	108.33%
5	100	$87.57	$105.14	$17.57	20.07%
6	200	$163.13	$185.28	$22.14	13.57%
7	300	$238.70	$265.41	$26.71	11.19%
8	400	$314.27	$345.55	$31.28	9.95%
9	500	$389.84	$425.69	$35.86	9.20%
10	600	$465.40	$505.83	$40.43	8.69%
11	700	$540.97	$585.97	$45.00	8.32%
12	800	$616.54	$666.10	$49.57	8.04%
13	900	$692.10	$746.24	$54.14	7.82%
14	1,000	$767.67	$826.38	$58.71	7.65%
15	1,100	$843.24	$906.52	$63.28	7.50%
16	1,200	$918.80	$986.66	$67.85	7.38%
17	1,300	$994.37	$1,066.79	$72.42	7.28%
18	1,400	$1,069.94	$1,146.93	$76.99	7.20%
19	1,500	$1,145.51	$1,227.07	$81.56	7.12%
20	2,000	$1,523.34	$1,627.76	$104.42	6.85%
21	2,500	$1,901.18	$2,028.45	$127.28	6.69%
22	3,000	$2,279.01	$2,429.14	$150.13	6.59%
23	3,500	$2,656.85	$2,829.83	$172.99	6.51%
24	4,000	$3,034.68	$3,230.52	$195.84	6.45%
25	5,000	$3,790.35	$4,031.90	$241.55	6.37%
26	6,000	$4,546.02	$4,833.28	$287.26	6.32%
27	7,000	$5,301.69	$5,634.66	$332.97	6.28%
28	8,000	$6,057.36	$6,436.04	$378.68	6.25%
29	9,000	$6,813.03	$7,237.42	$424.39	6.23%
30	10,000	$7,568.70	$8,038.80	$470.10	6.21%
31	12,500	$9,457.88	$10,042.25	$584.38	6.18%
32	15,000	$11,347.05	$12,045.70	$698.65	6.16%
33	17,500	$13,236.23	$14,049.15	$812.92	6.14%
34	20,000	$15,125.40	$16,052.60	$927.20	6.13%
35	25,000	$18,903.75	$20,059.50	$1,155.75	6.11%
36	30,000	$22,682.10	$24,066.40	$1,384.30	6.10%
37	35,000	$26,460.45	$28,073.30	$1,612.85	6.10%
38	40,000	$30,238.80	$32,080.20	$1,841.40	6.09%
39	45,000	$34,017.15	$36,087.10	$2,069.95	6.09%
40	50,000	$37,795.50	$40,094.00	$2,298.50	6.08%
41	60,000	$45,352.20	$48,107.80	$2,755.60	6.08%
42	70,000	$52,908.90	$56,121.60	$3,212.70	6.07%
43	80,000	$60,465.60	$64,135.40	$3,669.80	6.07%
44	90,000	$68,022.30	$72,149.20	$4,126.90	6.07%
45	100,000	$75,579.00	$80,163.00	$4,584.00	6.07%

Large Volume - 111

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$0.00	$125.00		
2	Delivery Charge	$0.14617	$0.17498		
3	PGA Rate	$0.57535	$0.57535		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$0.00	$125.00	$125.00	
5	100	$72.15	$200.03	$127.88	177.24%
6	200	$144.30	$275.07	$130.76	90.62%
7	300	$216.46	$350.10	$133.64	61.74%
8	400	$288.61	$425.13	$136.52	47.30%
9	500	$360.76	$500.17	$139.41	38.64%
10	600	$432.91	$575.20	$142.29	32.87%
11	700	$505.06	$650.23	$145.17	28.74%
12	800	$577.22	$725.26	$148.05	25.65%
13	900	$649.37	$800.30	$150.93	23.24%
14	1,000	$721.52	$875.33	$153.81	21.32%
15	1,100	$793.67	$950.36	$156.69	19.74%
16	1,200	$865.82	$1,025.40	$159.57	18.43%
17	1,300	$937.98	$1,100.43	$162.45	17.32%
18	1,400	$1,010.13	$1,175.46	$165.33	16.37%
19	1,500	$1,082.28	$1,250.50	$168.22	15.54%
20	2,000	$1,443.04	$1,625.66	$182.62	12.66%
21	2,500	$1,803.80	$2,000.83	$197.03	10.92%
22	3,000	$2,164.56	$2,375.99	$211.43	9.77%
23	3,500	$2,525.32	$2,751.16	$225.84	8.94%
24	4,000	$2,886.08	$3,126.32	$240.24	8.32%
25	5,000	$3,607.60	$3,876.65	$269.05	7.46%
26	6,000	$4,329.12	$4,626.98	$297.86	6.88%
27	7,000	$5,050.64	$5,377.31	$326.67	6.47%
28	8,000	$5,772.16	$6,127.64	$355.48	6.16%
29	9,000	$6,493.68	$6,877.97	$384.29	5.92%
30	10,000	$7,215.20	$7,628.30	$413.10	5.73%
31	12,500	$9,019.00	$9,504.13	$485.13	5.38%
32	15,000	$10,822.80	$11,379.95	$557.15	5.15%
33	17,500	$12,626.60	$13,255.78	$629.18	4.98%
34	20,000	$14,430.40	$15,131.60	$701.20	4.86%
35	25,000	$18,038.00	$18,883.25	$845.25	4.69%
36	30,000	$21,645.60	$22,634.90	$989.30	4.57%
37	35,000	$25,253.20	$26,386.55	$1,133.35	4.49%
38	40,000	$28,860.80	$30,138.20	$1,277.40	4.43%
39	45,000	$32,468.40	$33,889.85	$1,421.45	4.38%
40	50,000	$36,076.00	$37,641.50	$1,565.50	4.34%
41	60,000	$43,291.20	$45,144.80	$1,853.60	4.28%
42	70,000	$50,506.40	$52,648.10	$2,141.70	4.24%
43	80,000	$57,721.60	$60,151.40	$2,429.80	4.21%
44	90,000	$64,936.80	$67,654.70	$2,717.90	4.19%
45	100,000	$72,152.00	$75,158.00	$3,006.00	4.17%

General Distribution - 163

Line No.	(a)	(b) Present Rates	(d) Proposed Rates	(e)	(f)
1	Basic Service Charge	$500.00	$750.00		
2	Delivery Charge				
3	First 10,000 therms	$0.12424	$0.15686		
4	Next 10,000 therms	$0.11210	$0.14153		
5	Next 30,000 therms	$0.10534	$0.13300		
6	Next 50,000 therms	$0.06478	$0.08179		
7	Next 400,000 therms	$0.03297	$0.04163		
8	Over 500,000 therms	$0.03297	$0.02244		
9	PGA Rate	$0.00000	$0.00000		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
10	0	$500.00	$750.00	$250.00	50.00%
11	2,000	$748.48	$1,063.72	$315.24	42.12%
12	4,000	$996.96	$1,377.44	$380.48	38.16%
13	6,000	$1,245.44	$1,691.16	$445.72	35.79%
14	8,000	$1,493.92	$2,004.88	$510.96	34.20%
15	10,000	$1,742.40	$2,318.60	$576.20	33.07%
16	12,000	$1,966.60	$2,601.66	$635.06	32.29%
17	14,000	$2,190.80	$2,884.72	$693.92	31.67%
18	16,000	$2,415.00	$3,167.78	$752.78	31.17%
19	18,000	$2,639.20	$3,450.84	$811.64	30.75%
20	20,000	$2,863.40	$3,733.90	$870.50	30.40%
21	25,000	$3,390.10	$4,398.90	$1,008.80	29.76%
22	30,000	$3,916.80	$5,063.90	$1,147.10	29.29%
23	35,000	$4,443.50	$5,728.90	$1,285.40	28.93%
24	40,000	$4,970.20	$6,393.90	$1,423.70	28.64%
25	45,000	$5,496.90	$7,058.90	$1,562.00	28.42%
26	50,000	$6,023.60	$7,723.90	$1,700.30	28.23%
27	60,000	$6,671.40	$8,541.80	$1,870.40	28.04%
28	70,000	$7,319.20	$9,359.70	$2,040.50	27.88%
29	80,000	$7,967.00	$10,177.60	$2,210.60	27.75%
30	90,000	$8,614.80	$10,995.50	$2,380.70	27.64%
31	100,000	$9,262.60	$11,813.40	$2,550.80	27.54%
32	125,000	$10,086.85	$12,854.15	$2,767.30	27.43%
33	150,000	$10,911.10	$13,894.90	$2,983.80	27.35%
34	175,000	$11,735.35	$14,935.65	$3,200.30	27.27%
35	200,000	$12,559.60	$15,976.40	$3,416.80	27.20%
36	250,000	$14,208.10	$18,057.90	$3,849.80	27.10%
37	300,000	$15,856.60	$20,139.40	$4,282.80	27.01%
38	350,000	$17,505.10	$22,220.90	$4,715.80	26.94%
39	400,000	$19,153.60	$24,302.40	$5,148.80	26.88%
40	450,000	$20,802.10	$26,383.90	$5,581.80	26.83%
41	500,000	$22,450.60	$28,465.40	$6,014.80	26.79%
42	600,000	$25,747.60	$30,709.40	$4,961.80	19.27%
43	700,000	$29,044.60	$32,953.40	$3,908.80	13.46%
44	800,000	$32,341.60	$35,197.40	$2,855.80	8.83%
45	900,000	$35,638.60	$37,441.40	$1,802.80	5.06%
46	1,000,000	$38,935.60	$39,685.40	$749.80	1.93%

Market Based Distribution - 164

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$500.00	$750.00		
2	Delivery Charge				
3	First 10,000 therms	$0.12424	$0.15686		
4	Next 10,000 therms	$0.11210	$0.14153		
5	Next 30,000 therms	$0.10534	$0.13300		
6	Next 50,000 therms	$0.06478	$0.08179		
7	Next 400,000 therms	$0.03297	$0.04163		
8	Over 500,000 therms	$0.01777	$0.02244		
9	PGA Rate	$0.00000	$0.00000		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
10	0	$500.00	$750.00	$250.00	50.00%
11	2,000	$748.48	$1,063.72	$315.24	42.12%
12	4,000	$996.96	$1,377.44	$380.48	38.16%
13	6,000	$1,245.44	$1,691.16	$445.72	35.79%
14	8,000	$1,493.92	$2,004.88	$510.96	34.20%
15	10,000	$1,742.40	$2,318.60	$576.20	33.07%
16	12,000	$1,966.60	$2,601.66	$635.06	32.29%
17	14,000	$2,190.80	$2,884.72	$693.92	31.67%
18	16,000	$2,415.00	$3,167.78	$752.78	31.17%
19	18,000	$2,639.20	$3,450.84	$811.64	30.75%
20	20,000	$2,863.40	$3,733.90	$870.50	30.40%
21	25,000	$3,390.10	$4,398.90	$1,008.80	29.76%
22	30,000	$3,916.80	$5,063.90	$1,147.10	29.29%
23	35,000	$4,443.50	$5,728.90	$1,285.40	28.93%
24	40,000	$4,970.20	$6,393.90	$1,423.70	28.64%
25	45,000	$5,496.90	$7,058.90	$1,562.00	28.42%
26	50,000	$6,023.60	$7,723.90	$1,700.30	28.23%
27	60,000	$6,671.40	$8,541.80	$1,870.40	28.04%
28	70,000	$7,319.20	$9,359.70	$2,040.50	27.88%
29	80,000	$7,967.00	$10,177.60	$2,210.60	27.75%
30	90,000	$8,614.80	$10,995.50	$2,380.70	27.64%
31	100,000	$9,262.60	$11,813.40	$2,550.80	27.54%
32	125,000	$10,086.85	$12,854.15	$2,767.30	27.43%
33	150,000	$10,911.10	$13,894.90	$2,983.80	27.35%
34	175,000	$11,735.35	$14,935.65	$3,200.30	27.27%
35	200,000	$12,559.60	$15,976.40	$3,416.80	27.20%
36	250,000	$14,208.10	$18,057.90	$3,849.80	27.10%
37	300,000	$15,856.60	$20,139.40	$4,282.80	27.01%
38	350,000	$17,505.10	$22,220.90	$4,715.80	26.94%
39	400,000	$19,153.60	$24,302.40	$5,148.80	26.88%
40	450,000	$20,802.10	$26,383.90	$5,581.80	26.83%
41	500,000	$22,450.60	$28,465.40	$6,014.80	26.79%
42	600,000	$24,227.60	$30,709.40	$6,481.80	26.75%
43	700,000	$26,004.60	$32,953.40	$6,948.80	26.72%
44	800,000	$27,781.60	$35,197.40	$7,415.80	26.69%
45	900,000	$29,558.60	$37,441.40	$7,882.80	26.67%
46	1,000,000	$31,335.60	$39,685.40	$8,349.80	26.65%

Interruptible - 170

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$0.00	$250.00		
2	Delivery Charge	$0.12309	$0.12261		
3	PGA Rate	$0.57535	$0.57535		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$0.00	$250.00	$250.00	
5	500	$349.22	$598.98	$249.76	71.52%
6	1,000	$698.44	$947.96	$249.52	35.73%
7	1,500	$1,047.66	$1,296.94	$249.28	23.79%
8	2,000	$1,396.88	$1,645.92	$249.04	17.83%
9	2,500	$1,746.10	$1,994.90	$248.80	14.25%
10	3,000	$2,095.32	$2,343.88	$248.56	11.86%
11	3,500	$2,444.54	$2,692.86	$248.32	10.16%
12	4,000	$2,793.76	$3,041.84	$248.08	8.88%
13	4,500	$3,142.98	$3,390.82	$247.84	7.89%
14	5,000	$3,492.20	$3,739.80	$247.60	7.09%
15	6,000	$4,190.64	$4,437.76	$247.12	5.90%
16	7,000	$4,889.08	$5,135.72	$246.64	5.04%
17	8,000	$5,587.52	$5,833.68	$246.16	4.41%
18	9,000	$6,285.96	$6,531.64	$245.68	3.91%
19	10,000	$6,984.40	$7,229.60	$245.20	3.51%
20	11,000	$7,682.84	$7,927.56	$244.72	3.19%
21	12,000	$8,381.28	$8,625.52	$244.24	2.91%
22	13,000	$9,079.72	$9,323.48	$243.76	2.68%
23	14,000	$9,778.16	$10,021.44	$243.28	2.49%
24	15,000	$10,476.60	$10,719.40	$242.80	2.32%
25	17,500	$12,222.70	$12,464.30	$241.60	1.98%
26	20,000	$13,968.80	$14,209.20	$240.40	1.72%
27	22,500	$15,714.90	$15,954.10	$239.20	1.52%
28	25,000	$17,461.00	$17,699.00	$238.00	1.36%
29	30,000	$20,953.20	$21,188.80	$235.60	1.12%
30	35,000	$24,445.40	$24,678.60	$233.20	0.95%
31	40,000	$27,937.60	$28,168.40	$230.80	0.83%
32	45,000	$31,429.80	$31,658.20	$228.40	0.73%
33	50,000	$34,922.00	$35,148.00	$226.00	0.65%
34	60,000	$41,906.40	$42,127.60	$221.20	0.53%
35	70,000	$48,890.80	$49,107.20	$216.40	0.44%
36	80,000	$55,875.20	$56,086.80	$211.60	0.38%
37	90,000	$62,859.60	$63,066.40	$206.80	0.33%
38	100,000	$69,844.00	$70,046.00	$202.00	0.29%
39	125,000	$87,305.00	$87,495.00	$190.00	0.22%
40	150,000	$104,766.00	$104,944.00	$178.00	0.17%
41	175,000	$122,227.00	$122,393.00	$166.00	0.14%
42	200,000	$139,688.00	$139,842.00	$154.00	0.11%
43	225,000	$157,149.00	$157,291.00	$142.00	0.09%
44	250,000	$174,610.00	$174,740.00	$130.00	0.07%

CNG/600
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

DIRECT TESTIONY OF PAMELA J. ARCHER
REPRESENTING CASCADE NATURAL GAS CORPORATION

Revenue Proof / Tariffs

I. INTRODUCTION

Q. Please state your name, business address, and present position with Cascade Natural Gas Corporation.

A. My name is Pamela J. Archer and my business address is 8113 W. Grandridge Blvd., Kennewick, WA 99336. My present position is Supervisor, Regulatory Analysis for Cascade Natural Gas Corporation (Cascade or Company), a wholly-owned subsidiary of MDU Resources Group, Inc.

Q. Would you briefly describe your duties?

A. Yes. I supervise the preparation of regulatory reports and rate/tariff filings for regulatory approval, as well as provide regulatory and tariff advice and knowledge to others within the Company.

Q. Please briefly describe your educational background and professional experience.

A. I am a 1992 graduate of The Ohio State University with a B.S. in Chemical Engineering. In 1996, I graduated from Ashland University with a Master of Business Administration Degree. Prior to joining Cascade in September 2010, I was employed as an Energy Specialist at the Office of the Ohio Consumers' Counsel for fifteen years. I have received additional training at the Annual Regulatory Studies Program sponsored by the National Association of Regulatory Utility Commissioners (NARUC) at Michigan State University in 1992 as well as at multiple NARUC sponsored events. I have also taken post-graduate courses in Managerial Accounting, Corporate Finance, and Business Law at The Ohio State University.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the revenue proof shown in Exhibit CNG/601, and to explain various changes to Cascade's rate schedules proposed in this case. Cascade's revised tariff sheets are provided in Exhibit CNG/602.

II. REVENUE PROOF

Q. Would you please describe the revenue proof shown in Exhibit CNG/601?

A. Yes. The revenue proof shows the presentation of revenue at current rates and current volumes. The amount shown for current rates includes all the components of the rates, including gas costs, taxes, the public purposes charge and any billing adjustments for each rate schedule. The current rates shown match the amount of 2014 test year revenue which appears on the income statement.

Q. What is shown in the proposed rates section of the revenue proof?

A. The proposed rates section shows the proposed rates being applied to the pro forma volumes and pro forma billing determinants.

Q. Where did the pro forma volumes and billing determinants being used in this revenue proof originate?

A. These pro forma volumes and pro forma billing determinants come from the most recent IRP forecast and are addressed in more detail by the Company's witness Micah Robinson.

Q. Has the company made any type of adjustment because it has used these pro forma volumes and billing determinants?

A. Yes. The use of these pro forma amounts forms the basis of an adjustment to the revenue requirement which is described further in Michael Parvinen's testimony.

Q. What does the difference in the proposed rates and current rates show?

A. The difference between the proposed rates and current rates shows the revenue increase the Company is requesting in this case.

II. CHANGES TO CASCADE'S TARIFFS

Q. Did you prepare revised tariff sheets to reflect the rate increase and other tariff changes proposed in this case?

A. Yes, Cascade's revised tariff sheets are provided in Exhibit CNG/602.

Q. Did you rely on data provided by another witness to prepare the tariff sheets?

A. Yes, I relied on the cost-of-service study data and testimony provided by Ron Amen.

Q. Is the company proposing any changes to its present rate schedules?

A. Yes. The company is proposing to cancel several of its current tariffs because they describe programs that are no longer administered by the company and which are now administered for the Company in Oregon by the Energy Trust of Oregon.

Q. **Which schedules describe programs no longer being administered by the Company?**

A. Schedule No. 205 Promotional Concessions
Schedule No. 206 School Heat Conversion Finance Program
Schedule No. 207 Energy Efficient Water Heater Finance Program
Schedule No. 208 Idle Services Rebate Program
Schedule No. 209 Conversion Burner Upgrade Program
Schedule No. 220 High Efficiency Water Heater Rebate Program

Q. Is the Company proposing to make any additional changes to its rate schedules?

A. The Company is proposing to remove the language referring to optional pipeline capacity available under Schedule Nos. 185 and 186 from its General Distribution System Interruptible Transportation Service Schedule No. 163.

Q. Why is this language being removed?

A. This language is being removed from Schedule No. 163 because this service under Schedule Nos. 185 and 186 has been frozen for several years and is no longer available.

Q. Could you please describe the changes being proposed for Rate Schedule 111?

A. The Company is proposing to introduce a basic service charge in the amount of $125.00 per month. The justification for this proposal is included in Mr. Amen’s testimony, Exhibit CNG/500.

Q. Is the Company proposing to introduce a basic service charge for any other schedules?

A. Yes. The Company is also proposing to implement a basic service charge of $160.00 for Schedule No. 170, Interruptible Service. Once again, the justification for this proposed charge is shown in Mr. Amen's testimony.

Q. Is the Company proposing to make any other changes to its rate schedules?

A. Yes. The Company is proposing to rename the dispatching service charge currently found on Schedule No. 163 to a basic service charge.

Q. Why is the Company proposing to rename this charge?

A. The Company is proposing to rename the charge to a basic service charge since this more accurately describes the activities for which this charge is being assessed.

Q. Are there any other changes being proposed to the Company's tariffs in this proceeding?

A. Yes. The Company is proposing to make changes to Rule 19, Conservation Alliance Plan Mechanism ("CAP"), and Schedule No. 31, Public Purposes Funding, as discussed in Company witness Parvinen's testimony.

Q. Does this conclude your testimony?

A. Yes.

CNG/601
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

Pamela J. Archer
Exhibit No. 601

Revenue Proof

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2014 Through December 31, 2014

		Present Billing						Current Rates				Proposed Rates			
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Billing Determinants (Therms/Bills)	Rate	Margin	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)	(I)	(J)	(K)	(L)	(M) (K*L)
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	39,442,028	$0.35951	**$ 14,179,803**	**$ 2,759,784**		39,442,028 Therms	0.37960	**$ 14,972,194**
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	27,905,898	$0.25655	**$ 7,159,258**	**$ 1,190,908**		27,905,898 Therms	$ 0.298620	**$ 8,333,259**
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[1]				-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**								

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2014 Through December 31, 2014

		Present Billing					Current Rates				Proposed Rates			
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Billing Determinants (Therms/Bills)	Rate	Margin	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)	(I)	(J)	(K)	(L)	(M) (K*L)
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**	2,533,883	$0.18032	$ **456,910**	$ **(51,677)**		2,533,883 Therms	$ 0.211060	$ **534,801**
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**	548,762	$0.14617	$ **80,213**	$ **(6,682)**		548,762	$ 0.16322	$ **89,569**
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**								

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2014 Through December 31, 2014

Line No.	Rate Description	Present Billing: Percent Distribution	Present Billing: Billing Determinants (Therms/Bills)	Present Billing: Rate	Present Billing: Adjusted Billing Determinants	Present Billing: Weather Normalized Revenue (Margin)	Current Rates: Billing Determinants (Therms/Bills)	Current Rates: Rate	Current Rates: Margin	Current Rates: 2015 Revenue Adjustment	Proposed Rates: Percent Distribution	Proposed Rates: Billing Determinants (Therms/Bills)	Proposed Rates: Proposed Rate	Proposed Rates: Proposed Distribution Margin
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)	(G)	(H)	(I)	(I)	(J)	(K)	(L)	(M) (K*L)
Rate 111	**Firm Industrial Service**													
69	**Total Delivery Charge**		1,116,978	0.14617		**$ 163,269**	1,031,083	$0.14617	**$ 150,713**	**$ (12,555)**		1,031,083	0.16322	**$ 168,293**
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**	2,768,032	$0.12309	**$340,717**	**$ (3,861)**		2,768,032	0.12302	**$340,523**
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**								

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2014 Through December 31, 2014

		Present Billing					Current Rates				Proposed Rates			
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Billing Determinants (Therms/Bills)	Rate	Margin	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)	(I)	(J)	(K)	(L)	(M) (K*L)
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**

Test Year: January 1, 2014 Through December 31, 2014

		Present Billing					Current Rates				Proposed Rates			
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)	Billing Determinants (Therms/Bills)	Rate	Margin	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)	(I)	(J)	(K)	(L)	(M) (K*L)
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**
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**								

[1] Adjusting Cascade bill therms for gas used

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 287

Pamela J. Archer
Exhibit No. 602

Tariff Sheets

RULES & REGULATIONS

<u>RULE 19</u>- CONSERVATION ALLIANCE PLAN MECHANISM

APPLICABLE:

The Conservation Alliance Plan ("CAP") mechanism described in this rule applies to customers served on Residential General Service Rate Schedule 101 and Commercial General Service Rate Schedule 104.

(D)

PURPOSE:

The purpose of this provision is to (a) define the procedures for the annual tracking revisions in rates due to changes in the weather-normalized use per customer associated with Rate Schedule 101 & Rate Schedule 104; and (b) to define the procedures for the deferral of differences experienced between the actual average use per customer and the amount estimated at the time the Margin Rates were established.

REVISIONS TO COMMODITY MARGIN RATES DUE TO CHANGES IN THE WEATHER-NORMALIZED USE/CUSTOMER:

1. The Company shall use the baseline weather normalized average commodity margin per customer for Rate Schedule 101 and Rate Schedule 104 as reflected in its March 31, 2015 General Rate Filing. That application was based upon the weather normalized twelve months ended December 31, 2015. (C)

2. For each subsequent year for the term of this provision, the Company shall file annually (CAP Filing) with the Commission to update the Commodity Margin Rate for Rate Schedule 101 and Rate Schedule 104 based upon the weather normalized usage for the 12 months ending June 30th divided into the margin requirement of each rate schedule.

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's Spring Earnings Review filings, PGA Applications and other weather normalized report submittals.

4. The Total Commodity Margin Requirement of Rate Schedule 101 and Rate Schedule 104 shall be calculated by multiplying the baseline average commodity margin per customer per Rate Schedule, excluding any margin collected through the monthly Basic Service Charge, by the current twelve months ended June 30 average customer count based upon the average of the monthly bills issued.

5. The Margin Commodity Rate is calculated by dividing the Total Commodity Margin Requirement by the Total Weather Normalized Usage. (T)

DEFERRAL OF MARGIN COLLECTION DIFFERENCES:

1. The Company will maintain CAP variance deferral account as a Regulatory Asset or Liability. Each month, the Company will calculate the difference between the weather-normalized actual margin and the expected margin for rate schedules 101 and 104. Expected margin shall be the baseline average commodity per customer multiplied by the current customer count. The resulting dollar amount difference will be recorded in the CAP variance deferral account. (T)

(Continued on the next page)

PUBLIC PURPOSES FUNDING
SCHEDULE NO. 31

PURPOSE:

The purpose of this provision is to define the funding method for public purposes activities to be administered through one or more independent entities. Public purposes activities include, but may not necessarily be limited to, energy efficiency programs, market transformation and low-income conservation and bill assistance programs designed to benefit firm sales customers within Cascade Natural Gas's service territory in Oregon.

(D)

ADJUSTMENT TO RATES:
Effective April 1, 2014, a public purpose charge equal to 1.85% of current revenues, including customer service charges, in each month will be assessed as a line item on the bill of rate schedules 101 and 104 customers. The level of the public purpose charge will be reviewed and revised as necessary based on periodic evaluation of public purposes funding needs.

(D)

The Public Purposes Funds shall be allocated to specific separate accounts to fund the respective public purposes programs as follows:

- 2.26% will support public purpose funding of energy efficiency programs that replace programs previously administered by Cascade with energy efficiency programs administered by an independent entity.

- 0.34% will support public purpose funding for low-income conservation and bill assistance activities.

SPECIAL TERMS AND CONDITIONS:

1. 87% of the monies designated as public purpose funding will be transferred to the Energy Trust of Oregon. The Energy Trust of Oregon will use the funds to design, promote and administer Natural Gas energy efficiency programs in accordance with agreements executed between Cascade and the Energy Trust.

2. 13% of the monies designated as public purpose funding will be transferred to two internal program accounts and dispersed to Community Action Agencies (Agencies) for the purpose of adding or expanding low-income weatherization programs and bill assistance programs. For the period of September 1, 2008 through March 31, 2009 the entire funding will be used for bill payment assistance programs. Effective April 1, 2009, 75% of the funding will be designated for low-income conservation programs, and the remaining 25% will be designated for bill payment assistance. The internal accounts shall accrue interest at the Company's currently effective authorized rate of return.

(Continued on next page)

P.U.C. Or. No. 9

First Revision Sheet No. 31-A
Canceling
Original Sheet No. 31-A

CASCADE NATURAL GAS CORPORATION

PUBLIC PURPOSES FUNDING
SCHEDULE NO. 31

SPECIAL TERMS AND CONDITIONS: (Continued from Previous Page)

(D)

3. Each month, the Company will bill the public purposes surcharge on all rate schedule 101 and 104 customers bills. By the 20th of the month following the billing month, the Company will forward the amount of funds expected to be collected from billings issued for the prior calendar month, less a reserve for uncollectibles in an amount equal to Cascade's average percentage of net write-offs, to each fund administrator. Funds retained after the 20th of the month will earn interest at the Company's authorized rate of return until distributed to the fund administrators unless otherwise specified in an approved program or other agreement. (T)

4. The Company, and any independent entity selected to administer public purposes programs under this Tariff, will report program results as directed by the Commission. Copies of all reports provided by the fund administrators to the Commission shall also be submitted to the Company for review. (T)

5. All Public Purposes Funds will be allocated only to programs that are available within the Company's Oregon service territory. (T)

CNG/O15-03-01

ISSUED March 31, 2015 EFFECTIVE April 30, 2015

ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY **Scott W. Madison** TITLE **Executive Vice President**
and General Manager

Eighth Revision Sheet No. 101
Canceling
Seventh Revision Sheet No. 101

P.U.C. Or. No. 9

CASCADE NATURAL GAS CORPORATION

GENERAL RESIDENTIAL SERVICE RATE
SCHEDULE NO. 101

AVAILABILITY:

This schedule is available to residential customers throughout the territory served by the Company under the tariff of which this schedule is a part for natural gas supplied for all purposes provided adequate capacity and supply exists in the Company's system. Service under this schedule shall be through one or more meters at the option of the Company, provided they are located on contiguous property not divided by streets, roads, alleys, or other public thoroughfares. Meters on noncontiguous properties shall not be combined for billing purposes.

RATE:

Basic Service Charge		$3.00	per month	
All Therms per Month:				
Delivery Charge		$0.39393	per therm	(I)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.57789	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.00276)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.00137	per therm	
Schedule 193	CAP Temporary Adjustment	($0.02889)	per therm	
Schedule 194-A	UM 1283 Merger Credit	$0.00000	per therm	
Schedule 194-B	Other Residual Temporary Adjustments	$0.00003	per therm	
Schedule 195	Public Purposes Charge	$0.00000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm	
	Total Per Therm Rate	.94157	per therm	(I)

MINIMUM CHARGE:

Basic Service Charge $3.00

TERMS OF PAYMENT:

Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition.

TAX ADDITIONS:

The rates named herein are subject to increases as set forth in Schedule No. 100 for Municipal Exactions.

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate schedule is subject to the General Rules and Regulations of the Company as they may be in effect from time to time and as approved by the Oregon Public Utility Commission.

2. Gas purchased under this schedule shall not be submetered or resold to others without special permission from the Company.

Eighth Revision Sheet No. 104
Canceling
P.U.C. Or. No. 9 **Seventh Revision Sheet No. 104**

CASCADE NATURAL GAS CORPORATION

GENERAL COMMERCIAL SERVICE RATE
SCHEDULE NO. 104

AVAILABILITY:

This schedule is available to commercial customers throughout the territory served by the Company under the tariff of which this schedule is a part for natural gas supplied for all purposes provided adequate capacity and supply exists in the Company's system. Service under this schedule shall be through one or more meters at the option of the Company, provided they are located on contiguous property not divided by streets, roads, alleys, or other public thoroughfares. Meters on noncontiguous properties shall not be combined for billing purposes.

RATE:

Basic Service Charge		$3.00	per month	
All Therms per Month:				
Delivery Charge		$0.30708	per therm	(I)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.57789	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.00276)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.00000	per therm	
Schedule 193	CAP Temporary Adjustment	($0.02889)	per therm	
Schedule 194-A	UM 1283 Merger Credit	$0.00000	per therm	
Schedule 194-B	Other Residual Temporary Adjustments	$0.00003	per therm	
Schedule 195	Public Purposes Charge	$0.00000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm	
	Total Per Therm Rate	$0.85335	per therm	(I)

MINIMUM CHARGE:

Basic Service Charge $3.00

TERMS OF PAYMENT:

Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition.

TAX ADDITIONS:

The rates named herein are subject to increases as set forth in Schedule No. 100 for Municipal Exactions.

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate schedule is subject to the General Rules and Regulations of the Company as they may be in effect from time to time and as approved by the Oregon Public Utility Commission.

2. Gas purchased under this schedule shall not be submetered or resold to others without special permission from the Company.

CNG/O15-03-01

Issued March 31, 2015 Effective with Service on and After April 30, 2015

ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY **Scott W. Madison** TITLE **Executive Vice President**
and General Manager

Eighth Revision Sheet No. 105
Canceling
P.U.C. Or. No. 9 **Seventh Revision Sheet No. 105**

CASCADE NATURAL GAS CORPORATION

GENERAL INDUSTRIAL SERVICE RATE
SCHEDULE NO. 105

AVAILABILITY:

This schedule is available to industrial customers throughout the territory served by the Company under the tariff of which this schedule is a part for natural gas supplied for all purposes provided adequate capacity and supply exists in the Company's system. Service under this schedule shall be through one or more meters at the option of the Company, provided they are located on contiguous property not divided by streets, roads, alleys, or other public thoroughfares. Meters on noncontiguous properties shall not be combined for billing purposes.

RATE:

Basic Service Charge		$25.00	per month	(I)
All Therms per Month:				
Delivery Charge		$0.22603	per therm	(I)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.57789	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.00276)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.00019	per therm	
Schedule 193	CAP Temporary Adjustment	$0.00000	per therm	
Schedule 194-A	UM 1283 Merger Credit	$0.00000	per therm	
Schedule 194-B	Other Residual Temporary Adjustments	$0.00003	per therm	
Schedule 195	Public Purposes Charge	$0.00000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm	
	Total Per Therm Rate	$0.80138	per therm	(I)

MINIMUM CHARGE:

Basic Service Charge $25.00 (I)

TERMS OF PAYMENT:

Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition.

TAX ADDITIONS:

The rates named herein are subject to increases as set forth in Schedule No. 100 for Municipal Exactions.

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate schedule is subject to the General Rules and Regulations of the Company as they may be in effect from time to time and as approved by the Oregon Public Utility Commission.

2. Gas purchased under this schedule shall not be submetered or resold to others without special permission from the Company.

CNG/O15-03-01

Issued March 31, 2015 Effective with Service on and After April 30, 2015

ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY **Scott W. Madison** TITLE **Executive Vice President**
and General Manager

P.U.C. Or. No. 9

Eighth Revision Sheet No. 111
Canceling
Seventh Revision Sheet No. 111

CASCADE NATURAL GAS CORPORATION

LARGE VOLUME GENERAL SERVICE RATE
SCHEDULE NO. 111

AVAILABILITY:

This schedule is available throughout the territory served by the Company under the tariff of which this schedule is a part provided adequate capacity and supply exists in the Company's system. Service under this schedule shall be for natural gas supplied for all purposes to customers having an annual fuel requirement of not less than 50,000 therms and where the customer's major fuel requirement is for process use.

RATE:

Basic Service Charge		$125.00	per month	(N)
All Therms per Month:				
Delivery Charge		$0.17498	per therm	(I)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.57789	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.00276)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.00019	per therm	
Schedule 193	CAP Temporary Adjustment	$0.00000	per therm	
Schedule 194-A	UM 1283 Merger Credit	$0.00000	per therm	
Schedule 194-B	Other Residual Temporary Adjustments	$0.00003	per therm	
Schedule 195	Public Purposes Charge	$0.00000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm	
	Total Per Therm Rate	$0.75033	per therm	(I)

CONTRACT:

Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve (12) consecutive months' use. The Annual Minimum Quantity is to be negotiated and included as part of the contract but in no case shall the Annual Minimum Quantity be less than 50,000 therms.

ANNUAL DEFICIENCY BILL:

In the event customer purchases less than the Annual Minimum Quantity as stated in the contract, customer shall be charged an Annual Deficiency Bill. Annual Deficiency Bill shall be calculated as the difference between the Annual Minimum Quantity less actual purchase or transport therms times the difference between the per therm rates effective in this schedule and any modifying schedules less the weighted average commodity cost of system supply gas as such costs are reflected in the Company's tariff.

TERMS OF PAYMENT:

Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition.

TAX ADDITIONS:

The rates named herein are subject to increases as set forth in Schedule No. 100 for Municipal Exactions.

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate is subject to the General Rules and Regulations of the Company as they may be in effect from time to time and as approved by the Oregon Public Utility Commission.

2. Gas purchased under this schedule shall not be submetered or resold to others without special permission from the Company.

3. Service to the above customers shall be through one or more meters, at the option of the Company, provided they are located on contiguous property not divided by streets, roads, alleys, or other public thoroughfares. Meters on noncontiguous properties shall not be combined for billing purposes.

P.U.C. Or. No. 9

Eighth Revision Sheet No. 163
Canceling
Seventh Revision Sheet No. 163

CASCADE NATURAL GAS CORPORATION

GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE
SCHEDULE NO. 163

AVAILABILITY:

This unbundled distribution system interruptible transportation service schedule is available throughout the territory served by the Company under the tariff of which this schedule is a part, provided, in the sole judgment of the Company, there are adequate facilities in place at the existing distribution line or as such line may be enhanced by the Company from time to time to provide service. Service under this schedule shall be in conjunction with service provided under optional gas supply supplemental Schedule No. 183.

RATE:

A. Dispatching Service Charge $750.00 per month (I)

All customers receiving gas supply service through this schedule will be invoiced a monthly Dispatching Service Charge under this schedule or under one of the optional gas supply supplemental schedules, but in no event shall customer be billed a monthly Dispatching Service Charge under more than one schedule for service at a single metering facility.

B. Commodity Charge For All Therms Delivered Per Month

		Base Rate	Schedule 192	Schedule 194-A	Schedule 194-B	Schedule 196	Billing Rates		
First	10,000	0.15686	$0.00019	$0.00000	$0.00003	$0.00000	$0.15708	Per Therm Per Month	(I)
Next	10,000	0.14153	$0.00019	$0.00000	$0.00003	$0.00000	$0.14175	Per Therm Per Month	
Next	30,000	0.13300	$0.00019	$0.00000	$0.00003	$0.00000	$0.13322	Per Therm Per Month	
Next	50,000	0.08179	$0.00019	$0.00000	$0.00003	$0.00000	$0.08201	Per Therm Per Month	
Next	400,000	0.04163	$0.00019	$0.00000	$0.00003	$0.00000	$0.04185	Per Therm Per Month	(C)
Over	500,000	0.02244	$0.00019	$0.00000	$0.00003	$0.00000	$0.02266	Per Therm Per Month	(M)(I)

C. The total of all charges invoiced by Company shall be subject to a Gross Revenue Fee reimbursement charge to cover state utility tax and other governmental levies imposed upon the Company, as those fees and levies may be in effect from time to time.

All other terms and conditions of services shall be pursuant to the Rules and Regulations set forth in the Company's filed tariff.

OTHER SERVICES:

Service under this schedule shall include transportation on the Company's distribution facilities only. Access to interstate pipeline or other upstream facilities, either new or existing, shall be pursuant to other schedules if such services are to be obtained through the Company.

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(M) Denotes material moved from Sheet No. 164

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ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY **Scott W. Madison** TITLE **Executive Vice President**
and General Manager

GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE
SCHEDULE NO. 163
(Continued from Previous Page)

CONTRACT TERM:

The termination date of the contract in any year shall be September 30th of that year. In no event shall a term of a contract be less than one year. Said contract shall state the Annual Minimum Quantity of gas, the maximum daily volume of gas to be delivered under this distribution system capacity schedule as well as the optional gas supply supplemental schedule(s) and the optional pipeline capacity supplemental schedule(s) under which customer will be receiving all gas delivered by the Company. (T)

ANNUAL MINIMUM BILL:

Annual minimum charge is to be negotiated and included as part of contract between Company and customer and may be in addition to amounts otherwise due under this schedule.

TERM OF PAYMENT:

Above rates are net. Each monthly bill shall be due and payable fifteen (15) days from the date of rendition.

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate is subject to the general service provisions of the Company as they may be in effect from time to time and as approved by the Oregon Public Utility Commission.

2. Service under this schedule shall be rendered through metering facility at the single point of delivery.

3. Capacity under this schedule shall not be assigned to others without written approval from the Company.

TAX ADDITIONS:

The rates named herein are subject to increases as set forth in Schedule No. 100, entitled "Tax Additions".

P.U.C. Or. No. 9

Eighth Revision Sheet No. 164
Canceling
Seventh Revision Sheet No. 164

CASCADE NATURAL GAS CORPORATION

MARKET BASED DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE
SCHEDULE NO. 164

AVAILABILITY:

This unbundled distribution system interruptible transportation service schedule is available throughout the territory served by the Company under the tariff of which this schedule is a part, provided, in the sole judgment of the Company, there are adequate facilities in place at the existing distribution line or as such line may be enhanced by the Company from time to time to provide service; and further provided that customer has a feasible alternative to service under General Distribution System Interruptible Transportation Service Schedule No. 163, such as equal or lower cost alternative fuels, alternative distribution capabilities, or utilization of alternative plant locations outside of the Company's Oregon service area. Contracts for service under this schedule are subject to review and approval by the Oregon Public Utility Commission, pursuant to applicable statutes and Commission policies for market based rates. Service under this schedule shall be in conjunction with service provided under Optional Gas Supply Supplemental Schedule No. 183.

RATE:

A. Dispatching Service Charge: $500.00 per month

All customers receiving gas supply service through this schedule will be invoiced a monthly Dispatching Service Charge under this schedule or under one of the optional gas supply supplemental schedules, but in no event shall customer be billed a monthly Dispatching Service Charge under more than one schedule for service at a single metering facility.

B. Commodity Charge For All Therms Delivered Per Month

		Base Rate	Schedule 192	Schedule 194-A	Schedule 194-B	Schedule 196	Billing Rate	
First	10,000	0.12402	$0.00019	$0.00000	$0.00003	$0.00000	$0.12424	Per Therm Per Month
Next	10,000	0.11188	$0.00019	$0.00000	$0.00003	$0.00000	$0.11210	Per Therm Per Month
Next	30,000	0.10512	$0.00019	$0.00000	$0.00003	$0.00000	$0.10534	Per Therm Per Month
Next	50,000	0.06456	$0.00019	$0.00000	$0.00003	$0.00000	$0.06478	Per Therm Per Month
Next	400,000	0.03275	$0.00019	$0.00000	$0.00003	$0.00000	$0.03297	Per Therm Per Month
Over	500,000	0.01755	$0.00019	$0.00000	$0.00003	$0.00000	$0.01777	Per Therm Per Month

C. The total of all charges invoiced by Company shall be subject to a Gross Revenue Fee reimbursement charge to cover state utility tax and other governmental levies imposed upon the Company, as those fees and levies may be in effect from time to time.

All other terms and conditions of services shall be pursuant to the Rules and Regulations set forth in the Company's filed tariff.

OTHER SERVICES:

Service under this schedule shall include transportation on the Company's distribution facilities only. Access to interstate pipeline or other upstream facilities, either new or existing, shall be pursuant to other schedules if such services are to be obtained through the Company.

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ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY **Scott W. Madison** TITLE **Executive Vice President**
and General Manager

MARKET BASED DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE
SCHEDULE NO. 164
(Continued from Previous Page)

CONTRACT TERM:

Customers choosing **Market Based Distribution System Interruptible Transportation Service** under this schedule shall execute a service contract with a primary term at least through September 30, 1990. Primary terms ending after that date may be negotiated; provided that the termination date in any year shall be September 30 of that year. In no event shall a term of a contract be less than one year. Said contract shall state the Annual Minimum Quantity of gas, the maximum daily volume of gas to be delivered under this distribution system capacity schedule as well as the optional gas supply supplemental schedule(s) and the optional pipeline capacity supplemental schedule(s) under which customer will be receiving all gas delivered by the Company.

ANNUAL MINIMUM BILL:

Annual minimum charge is to be negotiated and included as part of contract between Company and customer and may be in addition to amounts otherwise due under this schedule.

TERM OF PAYMENT:

Above rates are net. Each monthly bill shall be due and payable fifteen (15) days from the date of rendition.

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate is subject to the general service provisions of the Company as they may be in effect from time to time and as approved by the Oregon Public Utility Commission.

2. Service under this schedule shall be rendered through metering facility at the single point of delivery.

3. Capacity under this schedule shall not be assigned to others without written approval from the Company.

TAX ADDITIONS:

The rates named herein are subject to increases as set forth in Schedule No. 100, entitled "Tax Additions".

INTERRUPTIBLE SERVICE
SCHEDULE NO. 170

AVAILABILITY:
This schedule is available throughout the territory served by the Company under the tariff of which this schedule is a part provided adequate capacity and supply exists in Company's system. Service under this schedule shall be for natural gas delivered for all purposes to customers having an annual fuel requirement of not less than 180,000 therms per year and where customer agrees to maintain standby fuel burning facilities and an adequate supply of standby fuel to replace the entire supply of natural gas delivered hereunder. Service under this schedule shall be subject to curtailment by the Company when in the judgment of the Company such curtailment or interruption of service is necessary. Company shall not be liable for damages for or because of any curtailment of natural gas deliveries hereunder.

RATE:

Basic Service Charge		$250.00	per month	(N)
All Therms per Month:				
Delivery Charge		$0.12261	per therm	(R)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.57789	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.00276)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.00019	per therm	
Schedule 193	CAP Temporary Adjustment	$0.00000	per therm	
Schedule 194-A	UM 1283 Merger Credit	$0.00000	per therm	
Schedule 194-B	Other Residual Temporary Adjustments	$0.00003	per therm	
Schedule 195	Public Purposes Charge	$0.00000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm	
	Total Per Therm Rate	$0.69796	per therm	(R)

CONTRACT:
Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve (12) consecutive months' use. Said contract shall state the maximum daily consumption of natural gas that Company agrees to deliver, as well as the Annual Minimum Quantity.

ANNUAL DEFICIENCY BILL:
In the event customer purchases less than the Annual Minimum Quantity as stated in the contract, customer shall be charged an Annual Deficiency Bill. Annual Deficiency Bill shall be calculated by multiplying the difference between the Annual Minimum Quantity and the therms actually taken ("Deficiency Therms") times the difference between the commodity rate in this Rate Schedule No. 170, as modified by any applicable rate adjustments, and the weighted average commodity cost of system supply gas as such costs are reflected in the Company's tariffs. If service is curtailed or interrupted by Company, the Annual Minimum Quantity shall be reduced by a fraction, the numerator of which is the actual number of days or fraction thereof, service was curtailed and the denominator of which is 365.

TERMS OF PAYMENT:
Each monthly bill shall be due and payable fifteen (15) days from the date of rendition.

UNAUTHORIZED USE OF GAS:
Gas taken by customer under this schedule by reason of its failure to comply with Company's curtailment order shall be considered as an unauthorized overrun volume. Company shall bill and customer shall pay for such unauthorized overrun at the rate of $0.50 per therm in addition to the regular charges incurred in the RATE section of this schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun.

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P.U.C. Or. No. 9 **First Revision Sheet No. 205**
Canceling
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CASCADE NATURAL GAS CORPORATION

PROMOTIONAL CONCESSIONS
SCHEDULE NO. 205

PURPOSE:

The purpose of this schedule is to summarize the major features of promotional concessions offered by the Company. The terms and conditions of the concessions are specified in greater detail in the program descriptions provided by the Company in compliance with OAR 860-26-025, which are available for public review in the Company's main office and its Oregon District Offices, as well as at the Commission's office in Salem.

Program	Initiated	Sheet No.	Effective Date	Advice Number
School Heat Conversion Finance Program	11/01/90	206	07/17/91	O91-06-01
Energy Efficient Water Heater Finance Program	01/01/91	207	07/17/91	O91-06-01
Idle Services Rebate Program	08/01/89	208	07/17/91	O91-06-01
Conversion Burner Upgrade Program	12/01/94	209	12/13/94	094-10-02

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BY **Scott W. Madison** TITLE **Executive Vice President and General Manager**

P.U.C. Or. No. 9

First Revision Sheet No. 206
Canceling
Original Sheet No. 206

CASCADE NATURAL GAS CORPORATION

SCHOOL HEAT CONVERSION FINANCE PROGRAM
SCHEDULE NO. 206

PURPOSE:

To identify and evaluate school heating equipment throughout the Company's service territory.

AVAILABLE:

To participating schools throughout the Company's service territory.

DESCRIPTION:

The Company will provide conversion cost financing assistance to schools that convert to natural gas heat.

IMPLEMENTATION DATE:

November 1, 1990.

ACCOUNTING TREATMENT:

Project costs will be assigned to Account 426.5 (Other Income Deductions)

(Continued on Sheet No. 207)

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ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY **Scott W. Madison** TITLE **Executive Vice President and General Manager**

ENERGY EFFICIENT WATER HEATER FINANCE PROGRAM
SCHEDULE NO. 207

PURPOSE:

To identify and evaluate all heat-only customers on the Company's system.

AVAILABLE:

To participating customers throughout the Company's service territory.

DESCRIPTION:

The Company will provide financing incentives to participating customers.

IMPLEMENTATION DATE:

January 1, 1991.

ACCOUNTING TREATMENT:

Project costs will be assigned to Account 426.5 (Other Income Deductions)

(Continued on Sheet No. 208)

P.U.C. Or. No. 9 **First Revision Sheet No. 208**
Canceling
Original Sheet No. 208

CASCADE NATURAL GAS CORPORATION

IDLE SERVICES REBATE PROGRAM
SCHEDULE NO. 208

PURPOSE:

To encourage use of existing natural gas facilities.

AVAILABLE:

To participating customers throughout the Company's service territory.

DESCRIPTION:

The Company will provide incentives toward installation of high efficiency natural gas water heaters, high efficiency natural gas space heater, or both.

IMPLEMENTATION DATE:

August 1, 1989.

ACCOUNTING TREATMENT:

Project costs will be assigned to Account 426.5 (Other Income Deductions)

(Continued on Sheet No. 209)

CONVERSION BURNER UPGRADE PROGRAM
SCHEDULE NO. 209

PURPOSE:

To provide an incentive to space heating equipment rental customers to upgrade their existing equipment which is presently secured through a rental agreement with Cascade through purchase of their own natural gas furnace or boiler.

AVAILABLE:

Residential heating equipment rental program customers presently renting heating equipment (conversion burner) under Rate Schedule No. 145 and heating their homes with natural gas.

DESCRIPTION:

The Company will provide financing, toward the purchase and installation of new natural gas furnace or boiler equipment (80% AFUE or better), to replace existing heating rental equipment (conversion burner).

IMPLEMENTATION DATE:

December 21, 1994.

ACCOUNTING TREATMENT:

Project costs will be assigned to Account 426.5 (Other Income Deductions)

HIGH EFFICIENCY WATER HEATER REBATE PROGRAM
SCHEDULE NO. 220

AVAILABILITY

This schedule is available throughout the territory served by the Company, to all existing, qualified residential and commercial customers currently using natural gas for purposes other than heating water. This program will commence June 1, 1993 and will be ongoing until canceled by the Company.

PURPOSE:

The purpose of the program is to provide a rebate incentive toward purchase and installation of efficient (minimum .60 energy factor) gas water heating equipment.

QUALIFICATION:

Program participants must meet the following criteria to be eligible for rebates:

1) Be an existing residential or commercial natural gas customer, served by the Company, that is not currently using natural gas for heating water.

2) Have an existing water heater(s) that uses an energy source other than natural gas. Gas to gas water heater replacements do not qualify for rebate incentives.

3) Install a new portable natural gas water heater with an energy factor rating of at least .60 and that conforms to all applicable state and local installation standards.

4) Install a new potable natural gas water heater that uses only natural gas as its energy source. Customers installing used equipment are not eligible for rebate incentives.

PROGRAM BENEFITS

Qualifying customers who purchase and install an approved, new potable natural gas water heater will receive a $200 rebate.

ADMINISTRATION:

1) Each high-efficiency water heater rebate request form must be accompanied by a proof of purchase receipt for the qualifying customer from the appliance dealer/installer who made the sale.

2) Only one rebate offer is valid per account. The rebate offer is non-transferable and not valid for renters. The rebate can only be redeemed by the home or business owner.

3) If the prospect desires financing under Cascade's Residential Financing Program, the rebate offer is available, but only as a down payment. The rebate cannot be redeemed for cash under the financing option.

HIGH EFFICIENCY WATER HEATER REBATE PROGRAM
SCHEDULE NO. 220
(Continued from Previous Page)

DEMAND SIDE MANAGEMENT (DSM) CONSIDERATIONS:

The energy savings value represents the portion of the program rebate that qualifies as a DSM measure. The DSM energy savings value portion of each program rebate will be determined as follows, assuming a water heater expected life of ten (10) years:

(Therm Savings) x (Ten Year Avoided Cost) = Energy Savings Value (DSM Component)

WHERE:

Therm Savings	=	Therm savings based upon the difference between annual therm sales under a standard (.53 energy factor) water heater and the qualifying (minimum .60 energy factor) water heater.
Avoided Cost	=	The Company's established ten year avoided cost on the date of installation
DSM Component	=	The portion of the program's rebate incentive eligible for rate recovery. through inclusion in the Company's approved rate base at the Company's next general rate adjustment application.

GENERAL RULES AND REGULATIONS:

This schedule is subject to the general rules and regulations contained in this tariff and to those prescribed by regulatory authorities.