CASCADE NATURAL GAS CORPORATION®
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

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May 31, 2013 **Advice No. CNG/W13-05-01**

Mr. Steven V. King
Acting Executive Director and Secretary
Washington Utilities & Transportation Commission
P.O. Box 47250
Olympia, WA 98504-7250

Re: Pipeline Replacement Plan and Cost Recovery Mechanism in Accordance with Commission Policy Statement in Docket UG-120715

Dear Mr. King:

In accordance with the Commission's policy statement in Docket UG-120715 Cascade hereby submits its twenty year replacement plan, cost recovery mechanism, and proposed tariff with a proposed effective date of November 1, 2013.

The attached is divided into three sections. The first section contains Cascade's master plan including a two year goal identifying specific projects. The second section contains Cascade's proposed Cost Recovery Mechanism (CRM). The third section is Cascade's proposed tariff based on estimated replacement costs for the period November 1, 2012, through October 31, 2013. Cascade will be updating estimates to actuals per the policy statement.

If there are any questions regarding the master plan please contact Jeremy Ogden at (509) 734-4509. For any other questions regarding this filing please contact me at (509) 734-4593.

Sincerely,

Michael Parvinen
Director, Regulatory Affairs

COST RECOVERY MECHANISM (CRM)
ELEVATED RISK PIPELINE FACILITY REPLACEMENTS
SCHEDULE NO. 597

APPLICABLE:

This adjustment applies to gas service rendered by the Company under the tariff of which this schedule is a part for service on and after the effective date hereof and shall be in addition to all rates and charges specified in this tariff.

MONTHLY RATES AND MINIMUM BILLS:

Each of the charges, except Demand and Customer Service Charges, are to be increased as shown:

Schedule 502 - $.00756 per therm
Schedule 503 - $.00756 per therm
Schedule 504 - $.00732 per therm
Schedule 505 - $.01026 per therm
Schedule 511 - $.00424 per therm
Schedule 512 - $.00537 per therm
Schedule 541 - $.00732 per therm
Schedule 570 - $.00109 per therm
Schedule 577 - $.00196 per therm

The delivery charge under Schedule No. 663 is to be increased by $0.00057.

SPECIAL TERMS AND CONDITIONS:

The rates named herein are subject to increases set forth in Schedule No. 500.

Pipeline Replacement Program Plan
Cascade Natural Gas Corporation
2013

in accordance with
Policy Statement in Docket No. UG-120715

Required Contents: Checklist and Table of Contents

Policy Statement		Section/Page
The pipe replacement program plan should consist of three parts: (1) a "master" plan for replacing all pipes with an elevated risk of failure;	In support of its pipe replacement program plan, each gas company should demonstrate that the type of pipe to be replaced under its program presents an elevated risk of cracking, leakage, breakage or other failure. The gas company should explain why the particular type(s) of pipe presents an elevated risk, such as the physical qualities of the pipe as manufactured (e.g., low ductile plastic pipe), the condition of the pipe as installed (e.g., poor soil conditions) or as maintained (e.g., no cathodic protection), the age of the pipe, etc. The gas company should also provide detailed analysis and explanation demonstrating why the pipe it seeks to replace is appropriate for replacement, compared to other pipe. To the extent practical, the gas company should quantify and explain the degree to which risk of failure is elevated for such pipe, compared to other pipe.	**Section 1 – Master Plan** Page 3
(2) a two-year plan that specifically identifies the pipe replacement program goals for the upcoming two year period;	The first pipe replacement program plan shall be filed by June 1, 2013, covering planned pipe replacement through 2015.	**Section 2 – Two-Year Plan** Page 5
and (3) if applicable, a plan for identifying the location of pipe that presents elevated risk of failure.	A prudent pipe replacement program should contain a plan for identifying the location of elevated risk pipe; to the extent the gas company does not presently know the location. The plan should include a timetable under which the gas company will know the location of its elevated risk pipe. The Commission will not require a gas company to know the location of all of its elevated risk pipe as a prerequisite for having a pipe replacement program consistent with the policy statement. A pipe replacement program may focus initially on pipe for which the gas company knows the location.	**Section 3 – Identification Plan** Page 6

Introduction

On December 31, 2012, the Washington Utilities and Transportation Commission issued a policy statement in Docket UG-120715 for the accelerated replacement of natural gas pipeline facilities with elevated risk. This policy statement requires each gas company requesting a special pipe replacement cost recovery mechanism (CRM) to file with the Commission a pipe replacement program plan containing the following elements:

1. *A "master" plan for replacing all pipes with an elevated risk of failure*
2. *A two-year plan that specifically identifies the pipe replacement goals for the upcoming two year period*
3. *A plan for identifying the location of pipe that presents elevated risk of failure*

Section 1 -Master Plan

This Master Plan will serve as the guide that Cascade Natural Gas Corporation (Cascade) will use to determine which pipelines should be replaced as part of the Pipe Replacement Program. This Master Plan will describe the possible risks that can be associated with a pipeline, how the pipelines are analyzed to assess and quantify risks, how the pipelines to be replaced are identified, and how information for identified and new risks is obtained. The Master Plan will also describe the role that Cascade's Distribution Integrity Management Plan (DIMP) plays in the Pipe Replacement Program.

Possible Risks

Cascade operates pipelines that are classified as Pre-CNG piping systems. Pre-CNG pipelines are distribution systems that were constructed to distribute manufactured gas. These pipelines were originally installed, owned, operated, and maintained by others prior to 1955, before natural gas was introduced to the Pacific Northwest. Cascade acquired a number of these systems in the late 1950s and throughout the 1960s. The condition of the pre-CNG pipe is bare steel or coal tar wrapped. This pipe is of concern since it is at least 60 years old and lacked cathodic protection until the early 1970s, leaving the pipe suspect to corrosion risk. The extent of this pipe varies throughout Cascade systems and depends on the history of the system and how it was acquired by Cascade. Gas distribution systems in Washington where the majority of this pre-CNG pipe resides are in the towns of Longview, Anacortes, and Shelton.

In addition to the risks inherent with Pre-CNG pipelines, Cascade's pipelines are exposed to risks due to the following factors:

- Corrosion
- Natural Forces
- Excavation Damage
- Other Outside Force Damage

- Material, Weld, or Joint Failure
- Equipment Failure
- Incorrect Operation
- Missing Data
- Other – Forces unique to a particular area on the system

Cascade's DIMP describes these risks in greater detail. Cascade's DIMP is on file with the Commission's Pipeline Safety Division.

Analysis and Quantification

As part of Cascade's DIMP, a GIS-based model has been created and is maintained. Information collected as part of DIMP is input into the model, where it is analyzed to find areas of concern and also trends. This allows Cascade to quantify the risk associated with each pipeline based on factors that are pertinent to this Pipe Replacement Program. Cascade's DIMP contains a more detailed explanation of this process.

Identification of Pipelines for Replacement

DIMP model results, modified to remove weighting factors that increase risk due to factors that do not apply to the intent of the Pipe Replacement Program (i.e. – population), are used to identify the locations of pipelines that should be considered for replacement. A sample of the DIMP model output for the Longview District is included in Appendix A.

Obtaining New Information

Cascade obtains new information for their DIMP model and Pipe Replacement Plan through the following methods:

1. Observing trending on DIMP – the DIMP model is analyzed on a yearly basis. As part of this analysis trends are identified and the plan and/or model are modified as needed.
2. Company forms that gather information on exposed pipelines – every time a Cascade pipeline is exposed an Integrity Management Dig Report – Form 625 is completed. Additionally, all leaks are documented with a Leak Investigation – Form 293. Information from these forms is input into the DIMP model.
3. Continuing Subject Matter Expert (SME) panel meetings – SME panel meetings are held on an as appropriate basis, at least once annually. Information from the panel meetings is used to validate the DIMP model and new information is input into the DIMP model.
4. Updating model annually – Cascade's DIMP model is updated annually. Results of the model analysis are used to prioritize pipeline replacement projects.

Cascade's DIMP describes these methods in greater detail.

Section 2 - Two Year Plan

Cascade's two year plan has been divided into three separate time periods. The time periods and the projects that are proposed for each are listed below.

November 1, 2012 – October 31, 2013

Project	Location	Type of Pipe to Be Replaced
Longview Bare Steel Replacement - Phase II	Longview, WA	Pre-CNG Bare Steel
Anacortes Bare Steel Replacement - Phase II	Anacortes, WA	Pre-CNG Bare Steel
Shelton Bare Steel Replacement - Phase I	Shelton, WA	Pre-CNG Bare Steel
Anacortes Bare Steel Replacement - Phase I	Anacortes, WA	Pre-CNG Bare Steel
Kelso Main Street Relocate	Kelso, WA	Pre-CNG Coal Tar Wrapped Steel
Wenatchee Bridge Crossing	Wenatchee, WA	Pre-CNG Painted Steel
Meyers Road Bridge Replacement	Zillah, WA	Pre-CNG Coal Tar Wrapped Steel

These projects were identified prior to the finalization of Cascade's DIMP Plan and Model. For that reason, SMEs were relied on to identify the projects.

November 1, 2013 – October 31, 2014

Project	Location	Type of Pipe to Be Replaced
Anacortes Bare Steel Replacement - Phase III	Anacortes, WA	Pre-CNG Bare Steel
Shelton Bare Steel Replacement - Phase II	Shelton, WA	Pre-CNG Bare Steel
Longview 12" HP Replacement - Phase I	Longview, WA	Pre-CNG Coal Tar Wrapped Steel
Moses Lake/Wenatchee Bare Steel Replacement - Phase I	Moses Lake and Wenatchee, WA	Pre-CNG Coal Tar Wrapped and Bare Steel
Longview/Kelso Bare Steel Replacement - Phase III	Longview, WA	Pre-CNG Bare Steel

These projects were identified through Cascade's DIMP model. The majority are intermediate pressure (IP) (<60 psig) pipelines and all are pre-CNG.

November 1, 2014 – October 31, 2015

Project	Location	Type of Pipe to Be Replaced
Shelton Bare Steel Replacement - Phase III	Shelton, WA	Pre-CNG Bare Steel
Longview 12" HP Replacement - Phase II	Longview, WA	Pre-CNG Coal Tar Wrapped Steel
Moses Lake Bare Steel Replacement - Phase II	Moses Lake, WA	Pre-CNG Coal Tar Wrapped and Bare Steel
Mt. Vernon Downtown Pipe Replacement	Mt. Vernon, WA	Pre-CNG Steel
Yakima District Pre-CNG Pipe Replacement	Various	Pre-CNG Steel
Moses Lake/Wenatchee Bare Steel Replacement - Phase II	Moses Lake and Wenatchee, WA	Pre-CNG Coal Tar Wrapped and Bare Steel

These projects were also identified through Cascade's DIMP model. The majority are intermediate pressure (IP) (<60 psig) pipelines and all are pre-CNG.

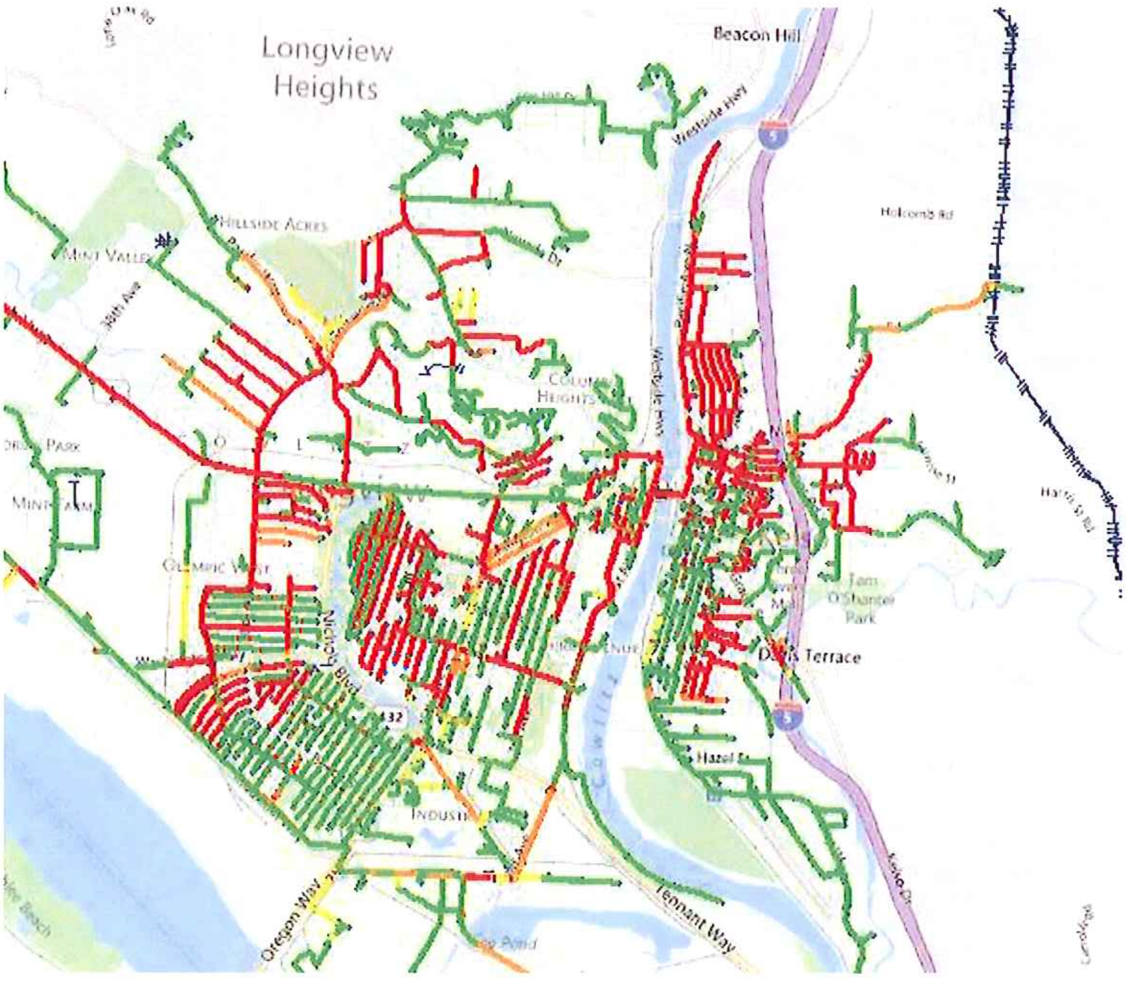
The projects listed in these tentative schedules are based on the best information available at this time. As more information becomes available and the DIMP model is updated, the prioritization of the projects may change.

Section 3 - Plan for Identifying the Location of Pipe that Presents Elevated Risk of Failure

Cascade identifies the location of pipe that presents an elevated risk of failure through the DIMP plan and model. The plan calls for information to be gathered on exposed pipe, leaks to be tracked, and SME knowledge to be incorporated into the plan. In addition, the plan has sufficient flexibility to identify and adjust to trends and new sources of information. Yearly analyses are performed that quantify the risks on each pipeline.

APPENDIX A

DIMP MODEL OUTPUT EXAMPLE



***Areas in red represent highest risk areas.**

Special Pipe Replacement Program Cost Recovery Mechanism ("CRM")

Cascade Natural Gas Corporation

2013

in accordance with

Policy Statement in Docket No. UG-120715

Required Contents: Checklist and Table of Contents

Policy Statement		Section/Page
Investment - Annual investment in pipeline replacement that would be eligible for recovery under the CRM is limited to elevated-risk pipe. The pipe must be readily identifiable in the company's pipeline replacement program plan by both location and timetable.	Costs recoverable under the CRM must not include: (1) the costs of locating pipe eligible for replacement; (2) pipeline costs associated with normal growth, system expansion, and repair and replacement of pipe damaged by third parties; and (3) the cost of pipe that a company is required to replace by a Commission order or approved settlement.	**Investment** Page 3
Accounting Treatment - A company would maintain its accounting records consistent with normal accounting. The CRM is intended to provide recovery of both a return on and a return of investment between general rate proceedings through annual rate increases.	The proposed mechanism would not provide for deferrals of costs, or the accrual of interest on that cost, for later recovery.	**Accounting Treatment** Page 3
Cost Recovery - A CRM would recover the return on the prior year's plant investment and recover depreciation expense associated with a company's elevated-risk pipe replacement investment program plan approved. For 2013, a company would be allowed to recover through the CRM approved replacement program costs incurred for the twelve month period November 1, 2012, to October 31, 2013. Recovery would be effective November 1, 2013, consistent with the company's annual purchased gas adjustment (PGA) filing and tariff.	On June 1 of each year a company that participates in a CRM must file actual and projected investment for that program year. The June 1 filing would include investment incurred from November 1 of the previous year to April 30 of the current year and projected costs from May 1 through October 31 consistent with the approved replacement plan. The company will update the projected costs with actual investment incurred during May through July and revised costs estimates for August through October with its annual Purchased Gas Adjustment tariff filing. Once actual project cost data are available, a company will submit actual cost data through September and an updated estimate for October under the PGA docket for that year.	**Cost Recovery** Page 3
Cost of Service - Each company will develop a cost of service considering investment and related elements provided for in the CRM.	The capital structure and cost of equity should be those used in its most recent general rate case.	**Cost of Service** Page 3
Cap on Amount Considered for Recovery - In its filing, each company will propose and support a cap for annual expenditures recoverable through the CRM for an elevated-risk pipe replacement program.	Companies may consider a percent of rate base, percent of revenues, total expenditures or other basis for its cap. As part of that proposal the company will address expected rate impact on customers and other factors supporting the cap.	**Cap on Amount Considered for Recovery** Page 3
Tariff and Billing - A company must file tariffed rates designed to recover the revenues reflected in the company's developed cost of service calculation for the rate year at least two months prior to the effective date of the company's PGA.	The company will include and identify separate recovery.	**Tariff and Billing** Page 4

Investment

Cascade has identified seven specific projects in its 2013 replacement plan that meet the criteria identified in the Commission's order in UG-120715. These projects are scheduled to be in service by November 1, 2013. The identified projects meet the criteria of the order as they are identified as elevated-risk pipe. The costs included are directly attributable to specific installation by location and do not include costs associated with growth or expansion, locating pipe, or is required replacement by other Commission order or settlement.

The expected total investment for the seven projects is $12,286,604. As of April 30, 2013, the actual investment incurred is $2,590,915.34. The detail of the budget and actual investment is shown in Attachment A to this document.

Accounting Treatment

Cascade has calculated a revenue requirement based on the rate year Average of Monthly Average (AMA) rate base assuming an in-service date of November 1, 2013. This calculation is also shown on Attachment A.

Cascade is tracking projects by specific work order as in the standard practice. No specific accounting treatment is being utilized or requested as part of this filing.

Cost Recovery

Cascade is proposing to recover a return on the average investment plus depreciation expense. The detailed calculation is included in Attachment A. The estimated revenue requirement associated with the identified projects is $2,050,135 (0.98%). Cascade will update the revenue requirement as required by order.

Cascade is basing its revenue requirement calculation based on the rate of return contained in the accepted settlement in UG-060256 of 8.85%

Cost of Service

Cascade is proposing to allocate the revenue requirement to rate schedules based on the overall rate base allocation from Cascade's rebuttal cost of service in UG-060256 (Exhibit ___ (JTS-15), Schedule 1 of 1, Page 1 of 1, line 28). As the docket was settled, no authorized cost of service methodology was accepted by the Commission.

A copy of the exhibit is included as Attachment B to this document

Cap on Amount Considered for Recovery

Cascade would propose that a cap based on no more than a 3% increase in overall revenues per year. A 3% cap would be based on the definition of a general rate case in WAC 480-07-505.

Cascade is proposing that the weather normalized adjusted revenues as shown in the annual Commission Basis Report filed under WAC 480-90-257 be used as the basis for the determination of the cap.

The effect of the proposed tariff in this filing is an increase in revenues of 0.98%.

Tariff and Billing

Cascade, as part of this filing, submits Tariff Schedule No. 597 entitled "Cost Recovery Mechanism (CRM) Elevated Risk Pipeline Replacements". The proposed effective date of the tariff is November 1, 2013.

Cascade is proposing that the billing rate be included on the bill as a component of the margin rate. Such placement on the bill would be consistent with the placement of these types of costs during a general rate case.

Attachment A

Revenue Requirement and
Rate Calculation
Spreadsheet

Replacement Projects 11-1-12 to 10-31-13

	Project		Estimtimated Cost	20-May-13 Actual Cost								
1	Longview Bare Steel Replacement - Phase II		$2,112,752									
2	Anacortes Bare Steel Replacement - Phase II		$1,442,855									
3	Shelton Bare Steel Replacement - Phase I		$1,727,646									
4	Anacortes Bare Steel Replacement - Phase I		$1,998,971	$1,998,971								
5	Kelso Main Street Relocate		$2,762,435									
6	Wenatchee Bridge Crossing		$591,945	$591,945								
7	Meyers Road Bridge		$1,650,000									
8	Total Estimated Replacement Cost		$12,286,604	$2,590,915								
				Schedule 503	**Schedule 502**	**Schedule 504**	**Schedule 512**	**Schedule 511**	**Schedule 505**	**Schedule 570**	**Schedule 577**	**Schedule 663**
9	Rate Base Allocation from UG-060256 Company COS		$218,725,267	$101,213,281	$1,206,702	$70,606,839	$26,846	$4,565,375	$8,230,589	$541,665	$103,353	$32,230,617
10	Percentage		100.00%	46.27%	0.55%	32.28%	0.01%	2.09%	3.76%	0.25%	0.05%	14.74%
11	Total Investment	Ln 7	12,286,604									
12	Depreciation Expense - Rate 2.58%	Ln 11* 2.58%	316,994	316,994								
13	Accumulated Depr. (Avg)	Ln 12 / 2	158,497									
14	Tax depreciation - Rate 5.00%	Ln 11 *5%	614,330									
15	Deferred Tax	(Ln 14 - Ln 12) * .35	104,068									
16	Accum Def Tax (Avg)	Ln 15 / 2	52,034									
17	FIT	Ln 12 * .35		110,948								
18	Rate Bate		12,076,073									
19	Authorized ROR from UG-060256		8.85%									
20	NOI	(Ln 18 * Ln 19) + (Ln 12 - Ln 17)	$1,068,732	$206,046								
21	Total NOI	(Ln 18 * Ln 19) + (Ln 12 - Ln 17)		$1,274,779								
22	Conversion Factor from Company Testimony in UG-060256			0.6218025								
23	Revenue Requirement	Ln 21 / Ln 22		$2,050,135								
24	Allocation Rev Req to Schedules	Ln 23 * Ln 19		$948,683	$11,311	$661,805	$252	$42,792	$77,146	$5,077	$969	$302,101
25	Weather Normalized 2012 Volumes			126,640,144	357,345	90,430,821	46,832	10,087,140	7,520,939	4,671,093	493,483	534,347,726
26	Rate Change	Ln 24 / Ln 25		$0.00749	$0.03165	$0.00732	$0.00537	$0.00424	$0.01026	$0.00109	$0.00196	$0.00057
27	502 and 503 Combined Rev. Req.				$959,993							
28	502 and 503 Combined Weather Norm. Vol.				126,997,489							
29	Combined 502 and 503 Rate Schedule	Ln 27 / Ln 28			$0.00756							
30	2012 Commission Basis Total Revenue			$210,121,191								
31	Percentage Increase in Revenue	Ln 23 / Ln 30		0.98%								

Attachment B

Cost of Service Determination
From Last General Rate Case
In Docket UG-060256

Cascade Natural Gas Corporation
Per Books Cost Allocation - 12 Months Ended September 30, 2005 - Adjusted
State of Washington
Commission Basis Summary Report

combine

Line No.	Description	TOTAL CODE	Total_Company	REOS 503	DO 502	GAC 541	COGS 504	CNG 512	LV 511	INDGS 505	INTGEN 570	INSINTINS 577	NCGEN 663	NCLV 664	NCSPECC 901
	Operating Revenues														
1	Rate Sched Revenue	REV_RS_	258,373,954	125,257,243	1,720,996	190,676	87,202,523	70,786	8,288,334	10,956,333	3,148,788	412,448	8,907,753	6,351,718	5,866,355
2	Gas Transportation Revenue	REV_OTH_GASTRANSP	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Other Operating Revenue	REV_OTH_OPER_REV	889,298	507,415	6,407	503	201,108	69	11,811	21,626	1,711	265	38,190	46,312	53,880
4	Total Revenue	REV	259,263,252	125,764,658	1,727,403	191,180	87,403,631	70,855	8,300,145	10,977,959	3,150,500	412,713	8,945,944	6,398,030	5,920,235
5															
6	Operating Expenses														
7	Total Cost of Gas	EXP_GAS	165,020,464	84,041,412	1,114,413	129,758	61,872,071	48,270	6,111,978	8,071,816	2,522,707	315,139	0	0	792,901
8	Manufactured Gas Production	EXP_O&M_P	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Distribution O&M Exp	EXP_O&M_D	7,682,852	3,296,128	36,500	6,163	2,106,595	514	92,623	245,334	27,178	5,831	560,671	534,553	770,763
10	Customer Accounts	EXP_O&M_CUST_ACCT	4,181,215	2,253,194	24,803	4,194	1,418,526	390	56,596	168,578	29,842	5,840	186,051	15,667	17,535
11	Customer Service & Information	EXP_O&M_CUST_SVIF	1,339,336	727,982	7,434	1,430	444,259	40	9,161	51,530	6,923	1,731	76,153	5,769	6,923
12	Customer Sales	EXP_O&M_CUST_SALE	441,710	241,335	2,465	474	147,277	13	3,037	17,083	2,295	574	25,246	1,913	0
13	Administration & General	EXP_A&G	16,915,982	6,431,050	77,071	11,482	4,296,435	1,849	274,242	525,135	87,794	13,962	1,994,141	2,949,244	253,578
14	Wage Adjustment	EXP_WAGE	1,369,561	647,392	7,242	1,201	415,387	112	19,313	48,572	4,420	904	73,879	69,128	82,010
15	Depreciation & Amortization	EXP_O&MDEPR	13,659,910	6,388,447	73,191	11,675	4,164,947	1,283	223,625	485,863	21,883	4,052	624,815	820,308	839,822
16	Total Expenses Excluding Taxes	EXP	210,611,030	104,026,938	1,343,119	166,378	74,865,496	52,471	6,790,574	9,613,911	2,703,041	348,032	3,540,955	4,396,582	2,763,532
17															
18	Operating Taxes														
19	Taxes Other Than Income	TAX	23,727,650	11,308,988	151,432	17,758	7,804,827	5,735	696,810	968,937	242,903	32,308	902,295	764,574	831,084
20	State Income Tax	TAX_BOOK_STATE	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Fed Income Taxes	IFIT	3,681,260	1,644,780	29,077	1,877	948,695	1,391	114,221	103,210	33,857	4,894	408,967	151,439	238,851
22	Total Taxes	TOTAL_TAXES	27,408,910	12,953,768	180,508	19,635	8,753,522	7,126	811,031	1,072,147	276,760	37,202	1,311,262	916,013	1,069,935
23															
24	Total Operating Rev. Deductions	TOTAL_DED	238,019,940	116,980,706	1,523,628	186,013	83,619,018	59,598	7,601,605	10,686,058	2,979,801	385,234	4,852,217	5,312,596	3,833,467
25															
26	Net Operating Income	NOI	21,243,312	8,783,952	203,775	5,167	3,784,613	11,257	698,540	291,900	170,699	27,479	4,093,727	1,085,435	2,086,768
27															
28	Rate Base	RB	239,332,551	101,213,281	1,206,702	187,520	70,419,319	26,846	4,565,375	8,230,589	541,665	103,353	14,418,479	17,812,138	20,607,284
29															
30	Rate of Return		8.88%	8.68%	16.89%	2.76%	5.37%	41.93%	15.30%	3.55%	31.51%	26.59%	28.39%	6.09%	10.13%
31															
32	Revenue to Cost Ratio - Current Rates			1.00	1.10	0.91	0.96	1.25	1.06	0.94	1.07	1.08	2.02	0.89	1.08
33	Revenue to Cost Ratio - Excl Gas Cost -Current Rates			0.99	1.34	0.77	0.87	2.72	1.27	0.80	1.46	1.43	2.02	0.89	1.09
34	Return at 9.37% ROR	XRET	22,413,493	9,478,624	113,008	17,561	6,594,769	2,514	427,547	770,795	50,727	9,679	1,350,291	1,668,107	1,929,872
35	Revenue Deficiency at 9.37%		1,881,918	1,117,191	-145,975	19,933	4,519,371	-14,061	-435,818	770,171	-192,942	-28,627	-4,412,070	937,069	-252,324
36	CNG Study Revenue to Cost Ratio - Excl Gas Cost			0.87	1.22	0.86	0.96	3.23	1.47	0.92	1.14	1.28	2.25	0.93	1.51
37	CNG Revenue Deficiency Calculation at 9.37%		11,727,512	10,415,379	-49,511	17,344	3,832,693	-13,345	-458,683	551,233	-21,966	-11,518	-3,530,426	2,010,306	-1,013,996
33															
34	New Rate Schdule Revenue at Requested Return														
35	New Rate Schdule Revenue at Requested Return	Customer	36,001,580	23,767,155	238,418	31,654	9,808,456	1,365	230,147	996,949	75,076	15,139	720,912	78,265	38,044
36	Commodity Revenue Requirement	Commodity	208,900,815	107,035,287	1,369,166	168,360	77,770,644	54,173	7,270,270	10,102,165	2,975,108	373,931	544,623	1,237,089	0
37	Capacity Revenue Requirement	Capacity	25,199,071	4,870,180	63,901	8,006	3,456,116	1,902	329,239	408,453	76,634	11,860	4,111,793	7,046,671	4,814,315
38	Revenue Revenue Requirements	Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Total Revenue Requirement at 9.37% ROR	Total	270,101,466	135,672,622	1,671,485	208,021	91,035,217	57,441	7,829,656	11,507,566	3,126,818	400,929	5,377,328	8,362,025	4,852,359
40															
41	Units for Unit Cost Report - Bills	UNITS	171,649	147,373	1,505	71	22,052	2	72	405	12	3	132	10	12
42	Units for Unit Cost Report - Therms	UNITS	700,566,944	99,536,929	1,437,349	162,388	73,487,657	61,548	7,861,569	10,240,163	3,277,558	409,432	90,413,328	155,960,514	257,718,509
43															
44	Customer Cost per Month		17.48	13.44	13.20	37.15	37.07	56.88	266.37	205.13	521.36	420.52	455.12	652.21	264.20
45	Commodity plus Capacity Cost per Therm		0.3342	1.1243	0.9970	1.0861	1.1053	0.9111	0.9667	1.0264	0.9311	0.9423	0.0515	0.0531	0.0187
38	Difference in Revenue Deficiency		-9,845,594	-9,298,188	-96,464	2,589	686,677	-716	22,865	218,938	-170,976	-17,109	-881,645	-1,073,237	761,672
39	Current Revenue (Cents/therm)												10.0	4.1	
40	Cost-of-Service Full Request (Cents/therm)												5.0	4.7	

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