Liberty Utilities

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STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 14-220

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

Winter 2014-2015 Cost of Gas Filing – Revised

October 15, 2014

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Winter 2014-2015 Cost of Gas Filing

REVISED DIRECT TESTIMONY

OF

DAVID B. SIMEK

October 15, 2014

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INTRODUCTION

Q. Please state your full name and business address.

A. My name is David B. Simek. My business address is 15 Buttrick Road, Londonderry, New Hampshire 03053.

Q. Please state by whom you are employed and your position.

A. I am a Senior Utility Analyst for Liberty Energy Utilities (New Hampshire) Corp. ("Liberty Energy NH") which is the sole shareholder of Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company") and provides service to EnergyNorth. I am responsible for providing rate-related services for the Company.

Q. Please describe your educational background and training.

A. I graduated from Ferris State University in 1993 with a Bachelor of Science in Finance. I received a Master's of Science in Finance from Walsh College in 2000. I also received a Master's of Business Administration from Walsh College in 2001. In 2006, I earned a Graduate Certificate in Power Systems Management from Worcester Polytechnic Institute.

Q. What is your professional background?

A. In August of 2013, I joined Liberty Energy NH as a Utility Analyst and I was promoted to a Senior Utility Analyst in August 2014. Prior to my employment at Liberty Energy NH, I was employed by NSTAR Electric & Gas ("NSTAR") as a Senior Analyst in Energy Supply from 2008 to 2012. Prior to my position in Energy Supply at NSTAR, I was a Senior Financial Analyst within the NSTAR Investment Planning group from 2004 to 2008.

Q. Have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission (the "Commission")?

A. Yes. I recently provided written and oral testimony before the Commission in Dockets DE 13-327, DE 14-013 and DE 14-086.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's proposed firm sales cost of gas rates for the 2014/15 Winter (Peak) Period and the Company's proposed 2014/15 Local Distribution Adjustment Charge both effective beginning November 1, 2014.

<u>COST OF GAS FACTOR</u>

Q. What are the proposed firm sales and firm transportation cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $1.1630 per therm for residential customers, $1.1666 per therm for commercial/industrial high winter use customers and $1.1384 per therm for commercial/industrial low winter use customers as shown on Proposed Seventeenth Revised Page 87. The Company proposes a firm transportation cost of gas rate of $0.0079 per therm as shown on Proposed Third Revised Page 89.

Q. Would you please explain tariff page Proposed Fifth Revised Page 86 and Proposed Seventeenth Revised Page 87?

A. Proposed Fifth Revised Page 86 and Proposed Seventeenth Revised Page 87 contain the calculation of the 2014/15 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 87, the proposed 2014/15 Average Cost of Gas of $1.1630 per therm is derived by adding the Direct Cost of Gas Rate of $1.1283 per therm to the Indirect Cost of Gas Rate of $0.0347 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $85,888,675. The estimated Indirect Cost of Gas, also derived on Page 86 and repeated on Page 87, is $2,643,707. The Direct Cost of Gas Rate of $1.1283 and the Indirect Cost of Gas Rate of $0.0347 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 76,121,808 therms.

To calculate the total Anticipated Direct Cost of Gas, the Company adds a list of allowable adjustments from deferred gas cost accounts to the projected demand and commodity costs for the winter period supply portfolio. These allowable adjustments, shown on Page 86, total $11,324,427. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $74,564,248 to determine the Total Anticipated Direct Cost of Gas of $85,888,675.

Q. What are the components of the Unadjusted Anticipated Cost of Gas?

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Third Revised Page 86 consists of the following components:

1.	Purchased Gas Demand Costs	$8,363,976
2.	Purchased Gas Commodity Costs	51,975,295
3.	Storage Demand and Capacity Costs	1,006,209
4.	Storage Commodity Costs	7,630,253
5.	Produced Gas Cost	5,455,799
6.	Hedge Contract Loss/(Savings)	132,716
	Total	$74,564,248

(Amounts do not add due to rounding)

Q. What are the components of the allowable adjustments to the Cost of Gas?

A. The allowable adjustments to gas costs, listed on Proposed Fifth Revised Page 86 are as follows:

1.	Prior Period Under Collection	$14,889,808
2.	Interest	323,286
3.	Broker Revenues	(1,099,927)
4.	Transportation COG Revenue	(362,665)
5.	Capacity Release Margin	(2,674,599)
6.	Hedging Costs	197,835
7.	Fixed Price Administrative Cost	50,689
	Total Adjustments	$11,324,427

(Amounts do not add due to rounding)

These allowable adjustments are standard adjustments that are made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. I will discuss the factors contributing to the prior period under collection later in this testimony.

Q. How does the proposed average cost of gas rate in this filing compare to the average cost of gas rate approved by the Commission in DG 13-251 for the 2013/14 Winter Period?

A. The average cost of gas rate proposed in this filing is $0.2735 per therm higher than the initial rate of $0.8895[1] approved by the Commission in Order No. 25,591 dated October 31, 2013 in DG 13-251. The increase in the rate reflects an increase in the total cost of gas of approximately $20.8 million or 30.7% ($21.6 million increase in total direct gas

[1] For comparison purposes, by the 2013/14 Winter Period, the residential cost of gas rate increased to $1.2919 per therm through the operation of the trigger mechanism.

costs and a $0.8M decrease in indirect gas costs). The $20.8 million increase in the total direct cost of gas is a result of a $12.8 million increase in commodity costs, a $1.7 million decrease in demand costs and a $9.7 million increase in adjustments.

The $12.8 million increase in commodity costs is due to a $14.4 million increase in pipeline commodity costs and a $1.6 million decrease in supplemental costs (underground storage, LNG, and propane). The $14.4 million increase in pipeline costs is due to a projected increase in commodity price of $14.4 million and a projected minimal decrease resulting from decreased pipeline throughput volumes. Total commodity gas costs (including hedges) are projected to be $0.1679/therm higher than last year. The $1.6 million decrease in demand costs is primarily due to the reallocation of 26,000 Dth of Dracut capacity from peaking to pipeline for the purposes of capacity assignment to the retail choice program. The $9.7 million increase in adjustments is primarily due to a $9.8 million increase in prior period under collections, which was partially offset by broker revenues, capacity release and off-system sales margins.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2013/14 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0079 per therm. The rate approved in Docket No. DG 13-251 was $0.0022. The increase in the rate relates to an approximate $363,000 in costs, partly due to the prior period under collection of $159,393 and the anticipated dispatch of propane during the winter period.

Q. In the calculation of its firm transportation winter cost of gas rate, has the Company updated the estimated percentage used for pressure support purposes?

A. No, it has not. The Company used, for pressure support purposes, a rate of 9.9% based on the marginal cost study used for the rate design approved in the Settlement Agreement in Docket No. DG 10-017.

Q. Schedule 25 shows an unaccounted for gas percentage ("UFG%") of 2.65%. Was that the percentage used in the Total Firm Volumes calculation in Schedule 1?

A. No. Page 21 of the Settlement Agreement in Docket No. DG 11-040 included a cap on the UFG% of 1.28%, and consistent with that settlement provision, 1.28% was used in the calculations. The Company would like to point out, however, that the cap calculation included in that Settlement Agreement used historical data that included data that was incorrect. Specifically, the 1.28% cap was developed based on the understanding that a meter at the Company's Tilton facility was a company use meter, when in fact that is not the case. The 2.65% calculation included on Schedule 25 excludes that meter from company use (and therefore increases UFG%). While the Company recognizes that the 1.28% cap was to remain in place until June 30, 2015 per the terms of the Settlement

Agreement in DG 11-040, it is important to have a benchmark that is not based on erroneous data. Further, in order for the Company to properly estimate Total Firm Volumes, the unaccounted for gas calculation needs to include actual percentages. The Company will be following up with Staff and the Office of Consumer Advocate to discuss an appropriate benchmark to be used for the remainder of the settlement term.

Q. Has the Company quantified the amount of additional costs attributable to the unaccounted for gas percentage in excess of the 1.28% cap?

A. Yes. The impact of using a 2.65% unaccounted for gas percentage rather than the 1.28% cap would have resulted in an increase to the total cost of gas of $10,507. By using the 1.28% cap, the Company is not seeking recovery of that amount.

Q. What was the actual weighted average firm sales cost of gas rate for the 2013/14 winter period?

A. The weighted average cost of gas rate was approximately $1.1068 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2013 through April 2014 to the monthly therm usage of an average residential heating customer using 800 therms per year, or 649 therms for the six winter period months.

PRIOR PERIOD UNDER COLLECTION

Q. Please explain the prior period under collection of $14,889,808.

A. The prior period under collection is detailed in the 2013/14 Winter Period Reconciliation Analysis included in Schedule 18 of this filing. The $14,889,808 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2014, including Peak Period costs recovered in May 2014 based on billings for April consumption. The under collection is primarily due to the direct result of sharp increases in gas prices in Tennessee's Zone 6 market area where the Company purchases a sizeable amount of its natural gas supplies. The price run up was attributable to a combination of increased demand from utilities and gas fired generators and a commensurate decrease in supply. This supply restriction was caused in part by a reduction of LNG imports and a continued lack of new pipeline infrastructure needed to bring incremental shale gas supplies into New England.

FIXED PRICE OPTION

Q. Has the Company established a winter period fixed price pursuant to its Fixed Price Option Program?

A. Yes. Pursuant to Order No. 24,515 in Docket No. DG 05-127 the Fixed Price Option Program ("FPO") rates are set at $0.0200 per therm higher than the initial proposed COG rate.[2] Proposed Third Revised Page 88 contains the FPO rate for the 2014/15 Winter period, which is $1.2425 per therm for residential customers. These compare to FPO rates approved for the 2013/14 winter period of $0.9095 per therm for residential customers. This represents a $0.3330 per therm, or 36.6%, increase in the residential FPO rate. The impact on the winter period bills for an average heating customer using 649 therms is an increase of approximately $249 or 28% compared to last winter. The bill impact reflects the implementation of the increase approved in Docket No. DG 14-041 effective July 1, 2014 relating to the cast iron/bare steel main replacement program. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $13 (or 1.0%) higher than the bill under the proposed cost of gas rates, assuming no monthly adjustments to the COG rate during the course of the winter. Schedule 23 contains the historical results of the FPO program. Consistent with Order No. 25,691 issued on July 10, 2014 in Docket No. DG 14-133, the FPO program is no longer available to commercial and industrial customers and is now only available to residential customers. This change reduced the Company's unhedged volume risk by recognizing that commercial and industrial customers can buy natural gas from competitive suppliers and obtain a fixed price.

[2] The Company's September 2, 2014 filing included a COG rate of $1.2225 per therm and an FPO rate of $1.2425 per therm. Per Order No. 24,515 at 10, "the FPO…rate offering[s] will be as contained in the initial COG filing." As compared to the revised COG rate in this updated filing, the FPO rate is $0.0795 per therm higher than the COG rate.

HEDGED SUPPLIES

Q. Has the Company hedged any of its winter period supplies pursuant to its proposed Natural Gas Price Risk Management Plan?

A. Yes, it has. As shown in Schedule 7, Page 2, the Company has hedged a total of 490,100 Dekatherms (4.9 million therms) at a weighted average fixed price of $4.4508 per Dekatherm. The hedged price reflects the higher cost of gas during the period that the hedged volumes were locked in.

Q. On what dates and at what prices did the Company contract for these supplies?

A. The Company has 17 contracts that hedge the price of gas supplies for the 2014/15 Winter Period with prices ranging from $3.930 to $4.923 per Dekatherm. The contracts date from October 11, 2013 through July 3, 2014. The contract dates, volumes and prices are listed in Schedule 7 pages 2 through 4.

LOCAL DISTRIBUTION ADJUSTMENT CHARGE

Q. What are the surcharges that will be billed under the LDAC?

A. The Company is submitting for approval an LDAC of $0.0772 per therm for the residential non-heating class and residential heating class, and $0.0628 per therm for the commercial/industrial bundled sales classes. The surcharges that are proposed to be billed under the LDAC are the Energy Efficiency Charge, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation and the Residential Low Income Assistance Program charge.

Q. Please explain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the projected expenses associated with the Company's energy efficiency programs for Calendar Year 2015 that will be filed with the Commission in the near future. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period over recovery of the Company's Residential and Commercial energy efficiency programs as of October 2014. The Energy Efficiency Charge is also designed to recover performance-based incentives associated with the Company's energy efficiency programs during the period January–December 2013 that were filed with the Commission in DE 10-188 on May 31, 2013 and are included in the costs to be recovered.

Q. What is the proposed Residential Low Income Assistance Program, ("RLIAP"), charge?

A. The proposed RLIAP charge is $0.0071 per therm. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this program. For the 2014/15 Winter Period the Company is providing a 60%

base rate discount, consistent with the settlement agreement approved by the Commission in Order No. 24,669 in DG 06-120. The current RLIAP charge is designed to recover $1,175,867, of which $1,450,987 is for the revenue shortfall resulting from 5,261 customers receiving a 60% discount off their base rates, and ($275,120) is for the prior year reconciling adjustment.

Q. In Order No. 24,824 in Docket No. DG 06-122 relating to short term debt issues, the Company agreed to adjust its short term debt limits each year as part of the Company's Winter Period cost of gas filing. Did the Company calculate the short-term debt limit for fuel and non-fuel purposes in accordance with this settlement?

A. Yes, the Company included in Schedule 24 the short-term debt limit for fuel and non-fuel purposes for the 2014-15 period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2014 through October 31, 2015 is calculated to be $26,559,715 and the limit for non-fuel purposes is calculated to be $59,263,829.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 91)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism as well as the third party recoveries are presented in the Environmental Cost Summary included in Schedule 20 of this filing. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations with regard to these sites, as described by Ms. Casey in her pre-filed testimony in this proceeding and as set forth in the MGP site summaries included in this filing under Schedule 20. The Summary included in Schedule 20, pages 1 – 8, shows the remediation cost pools for the Concord, Manchester, Nashua, Dover, Laconia and Keene sites and a General Pool for costs that cannot be directly assigned to a specific site. The filing also includes amounts recovered from insurance companies shown in the section labeled "Cash Recoveries" on the Environmental Cost Summary, pages 9 - 12. These cash recoveries from insurance companies are listed under the headings for the Concord, Laconia, Manchester, Nashua, Dover, and Keene sites. Page 13 of Schedule 20 provides the total remediation and recovery costs and collections by year and cumulative through this filing.

The 2013-2014 remediation costs that the Company is including in this filing are shown in confidential attachment A. Included in the remediation costs are two prior year's audit adjustments, one in the amount of ($1,876) and the other in the amount of $8,242.86.

A summary sheet and detailed backup spreadsheets that support the 2013-2014 costs are provided in Schedule 20 of this filing. Consistent with past practice, the Company met with the Commission Staff and OCA in August of this year to update them on the status of environmental matters. Ms. Casey's testimony describes the Company's activities with regard to all six sites.

Q. In Docket No. DG 12-265, the Company indicated that approximately $79,000 of environmental costs had been embedded in the approved base rate tariffs. How did the Company reflect those revenues in its calculation of its Environmental Surcharge?

A. The Company has modified its Environmental Cost Summary on Schedule 20 to include the base rate recoveries for the period June 2010 through October 2014. The Company determined these recoveries by multiplying the base rate component associated with the environmental costs by the monthly volumetric throughput during the period June 2010 through October 2014. The environmental rate that was embedded in the base rates was calculated by simply dividing the total embedded cost of $78,892 by the 2008-2009 test year normalized throughput level of 148,771,890 therms to derive a charge of $0.0005/therm.

Q. Please describe how the Company calculated the Environmental Surcharge included in this filing.

A. The proposed Manufactured Gas Plant Remediation surcharge for the period beginning November 1, 2014 and ending October 31, 2015 is $0.0055 per therm. This surcharge will recover a total of $996,678 in amortized remediation costs less the $78,892 in base rate collections for a net of $917,786. The costs submitted for recovery are presented in the Environmental Cost Summary included in Schedule 20 of this filing.

Q. Does the LDAC include a credit for Interruptible Transportation Margins?

A. No, the Company has not provided any service under the classification over the past year and therefore has not earned any margins to credit back to sales customers. In the Company's current base distribution rate case filing, Docket No. DG 14-180, we have proposed to eliminate the Interruptible Transportation Service rate as no customers have taken service under that rate for several years.[3]

Q. Did the Company include a Rate Case Expense surcharge in this filing?

A. No. As shown on Schedule 19 RCE, there is currently an over-collection in that account of $123,489. Consistent with discussions held with Staff, the over-collection will be applied against expenses incurred in the current base rate case. In the interim, the over-collection balance will continue to accrue interest.

Q. Has the Company also updated its Company Allowance percentage for the period November 2014 through October 2015 in accordance with Section 8.1 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 the Company has recalculated its Company Allowance for the period

[3] See Joint Testimony of Stephen R. Hall and James D. Simpson in Docket No. DG 14-180.

November 2014 – October 2015. The Company calculated the Company Allowance of 2.94% based on sendout and throughput data for the twelve-month period ending June 2014. This recalculated Company Allowance is proposed to be applied to all supplier deliveries beginning in November 2014.

CUSTOMER BILL IMPACTS

Q. What is the estimated impact of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer's seasonal bill as compared to the rates in effect last year?

A. The bill impact analysis is presented in Schedule 8 of this filing. These bill impacts include the base distribution rates approved in Order No. 25,684 in Docket No. DG 14-041 relating to the cast iron/bare steel main replacement program. The total bill impact over the winter period for an average residential heating customer is an increase of approximately $72, or 7.1%. The total bill impact for an average commercial/industrial G-41 customer is an increase of approximately $146, or 5.1%. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

OTHER TARIFF CHANGES

Q. Is the Company updating its Delivery Terms and Conditions in the filing?

A. Yes. The Company is submitting Proposed Third Revised Page 155 relating to Supplier Balancing and Peaking Demand Charges and Proposed Third Revised Page 156 relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 155.

A. In Proposed Third Revised Page 155, the Company is updating the Peaking Demand Charge from $21.00 per MMBtu of Peak MDQ to $18.22 per MMBtu of Peak MDQ, a $2.78 decrease. This calculation is also presented in Schedule 21.

Q. Please describe the changes to tariff Page 156.

A. Proposed Third Revised Page 156 updates the Capacity Allocator percentages used to allocate pipeline, storage and local peaking capacity to high and low load factor customers under the mandatory capacity assignment requirement for firm transportation service. Schedule 22 contains the six-page worksheet that backs up the calculations for the updated allocators.

OCCUPANT BILLING

Q. **Has there been any change, or are changes being considered, in the Occupant Account billing policy?**

A. Yes. The Company is formulating a plan for dealing with occupant billing and will provide the plan to Staff and OCA for their review on or before October 15th.

Q. Does this conclude your testimony?

A. Yes, it does.

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