STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 13-___

EnergyNorth Natural Gas, Inc. d/b/a Liberty Utilities
Winter 2013-14 Cost of Gas Filing

DIRECT TESTIMONY

OF

MARK G. SAVOIE

September 3, 2013

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INTRODUCTION

Q. Mr. Savoie, please state your full name and business address.

A. My name is Mark G. Savoie. My business address is 11 Northeastern Blvd., Salem, New Hampshire 03079.

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

A. In December 2012, I became employed by Liberty Energy NH as a Utility Analyst. My primary duties include preparing the gas cost recovery projections for Liberty and related reconciliations, administering the Company's tariff, calculating the achieved rate of return, and appearing as a witness on rate matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Accounting in 1980 and a Master of Business Administration in 1995, both at Southern New Hampshire University (formerly, New Hampshire College). I have worked for regulated public utilities or a related company for a total of approximately 22 years. From 2006 to 2012, I was employed by Pennichuck Corporation as Manager of Financial Reporting, Business Planning and Analysis. My duties included primarily Securities and Exchange Commission ("SEC") reporting, tax compliance and various treasury functions. From 1985 to 1986, I was the Accounting Manager for Concord Natural Gas, a wholly-owned subsidiary of

EnergyNorth, Inc. From 1986 to 2006, I was the Tax/SEC Accountant for EnergyNorth, Inc. My primary duties as Tax/SEC Accountant included SEC reporting and Tax compliance. From 1996 to 2000, I was a Rate Analyst and was subsequently promoted to Manager of Regulatory Affairs for EnergyNorth. My primary duties as Rate Analyst and Manager of Regulatory Affairs included determining and administering rates, including calculating the cost of gas adjustment, analysis of rate of return, working capital calculations, and developing, monitoring and evaluating risk management policies and procedures. I also worked for approximately ten years for various public accounting firms, primarily as an auditor.

Q. Do you have any professional licenses?

A. Yes, I am licensed in the State of New Hampshire as a Certified Public Accountant.

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

A. Yes, I testified in DG 13-085, Liberty's 2013 summer cost of gas proceeding and in DG 13-149, Liberty's Cast Iron/Bare Steel Replacement Program. I have also testified in a number of regulatory proceedings before the Commission from 1996 to 2000 on a variety of matters for EnergyNorth that included cost of gas proceedings (DG 00-034 and DG 00-193), a recovery mechanism for costs related to clean-up of manufactured gas sites (DG 99-060), the hedging program (DR 97-140), the Natural Gas Price Stability

Plan (DR 98-029) and a petition for approval of a gas transportation agreement with AES Londonderry (DG 00-145).

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 2013/14 Winter (Peak) Period and the Company's proposed 2013/14 Local Distribution Adjustment Charge both effective beginning November 1, 2013.

<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 $0.8895 per therm for residential customers, $0.8908 per therm for commercial/industrial high winter use customers and $0.8807 per therm for commercial/industrial low winter use customers as shown on Proposed Eleventh Revised Page 87. The Company proposes a firm transportation cost of gas rate of $0.0022 per therm as shown on Proposed Second Revised Page 89.

Q. Would you please explain tariff page Proposed Third Revised Page 86 and Proposed Eleventh Revised Page 87?

A. Proposed Third Revised Page 86 and Proposed Eleventh Revised Page 87 contain the calculation of the 2013/14 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 2013/14 Average Cost of Gas of $0.8895 per therm is derived by adding the Direct Cost of Gas Rate of $0.8438 per therm to the Indirect Cost of Gas Rate of $0.0457 per therm. The estimated total Anticipated Direct Cost of gas, derived on Page 86 and repeated on Page 87, is $64,239,567. The estimated Indirect Cost of Gas, also derived on Page 86 and repeated on Page 87, is $3,475,875. The Direct Cost of Gas Rate of $0.8438 and the Indirect Cost of Gas Rate of $0.0457 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 76,131,660 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 $1,598,954. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $62,640,614 to determine the Total Anticipated Direct Cost of Gas of $64,239,567.

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	$9,177,351
2.	Purchased Gas Commodity Costs	40,933,156
3.	Storage Demand and Capacity Costs	1,048,770
4.	Storage Commodity Costs	9,264,012
5.	Produced Gas Cost	1,649,458
6.	Hedge Contract Loss/(Savings)	567,867
	Total	$62,640,614

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

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

1.	Prior Period Under Collection	$5,118,679
2.	Interest	122,093
3.	Broker Revenues	(773,129)
4.	Transportation COG Revenue	(93,511)
5.	Capacity Release Margin	(3,018,069)
6.	Hedging Costs	197,835
7.	Fixed Price Administrative Cost	45,056
	Total Adjustments	$1,598,954

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 12-265 for the 2012/13 Winter Period?

A. The average cost of gas rate proposed in this filing is $0.2176 per therm higher than the initial rate of $0.6719 approved by the Commission in Order No. 25,435 dated October 30, 2012 in DG 12-265. This increase in the rate reflects an increase in the total cost of gas of approximately $15.5 million or 29.6% (an $15.4 million increase in total direct gas costs and a $0.1 million increase in indirect gas costs). The $15.4 million increase in the total direct cost of gas is a result of a $14.4 million increase in commodity costs, a $0.3 million decrease in demand costs and a $1.3 million increase in adjustments.

The $14.4 million increase in commodity costs is due to a $12.9 million increase in pipeline commodity costs and a $1.5 million increase in supplemental costs (underground storage, LNG, and propane). The $12.9 million increase in pipeline costs is due to a projected increase in commodity price of $14.4 million and a projected decrease of $1.5 million resulting from decreased pipeline throughput volumes. Total commodity gas costs (including hedges) are projected to be approximately $.2606/therm higher than last year. The $1.3 million increase in adjustments reflects a $3.5 million increase in prior period under collection and inclusion of hedging costs related to the purchase of options in the amount of $0.2 million, which was offset by a $2.3 million increase in 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 2012/13 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0022 per therm. The rate approved in DG 12-265 was $0.0002. This increase is partly due to the prior period under collection of $33,351 and the anticipated dispatch of LP 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 DG 10-017. That rate was applied to the Peak 2012/13 Cost of Gas filing.

Q. What was the actual weighted average firm sales cost of gas rate for the 2012/13 winter period?

A. The weighted average cost of gas rate was approximately $0.7680 per therm. This was calculated by applying the actual monthly cost of gas rates for November 2012 through April 2013 to the monthly therm usage of an average residential heating customer using 797 therms per year, or 650 therms for the six winter period months.

PRIOR PERIOD UNDER COLLECTION

Q. Please explain the prior period under collection of $5,118,679.

A. The prior period under collection is detailed in the 2012/13 Winter Period Reconciliation Analysis included in Tab 18 of this filing. The $5,118,679 under collection is the sum of the deferred gas cost, bad debt, and working capital balance as of April 30, 2013, including Peak Period costs recovered in May 2013 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 increase 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, in Order No. 24,515 in docket DG 05-127, dated September 16, 2005, the Commission approved an amendment to the Fixed Price Option Program ("FPO"). In accordance with the approved changes to the FPO, the FPO rates are set at $0.02 per therm higher than the initial proposed COG. Proposed Second Revised Page 88 contains the FPO rates for the 2013/14 Winter period, which are $0.9095 per therm for residential customers, $0.9108 per therm for commercial/industrial high winter use customers, and $0.9007 per therm for commercial/industrial low winter use customers. These compare to FPO rates approved for the 2012/13 winter period of $0.6919 per therm for residential customers, $0.6936 per therm for commercial/industrial high winter use customers, and $0.6871 per therm for commercial/industrial low winter use customers. This represents a $0.2176 per therm, or 31.4%, increase in the residential FPO rate. The impact on the winter period bills for an average heating customer using 650 therms is an increase of approximately $145 or 19.5% compared to last winter. The bill impact reflects the implementation of the increase approved in DG 13-149 effective July 1, 2013 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 1.5% higher than the bill under the proposed cost of rates assuming that the COG is not revised prior to final approval by the Commission and also assuming no monthly adjustments to the COG rate during the course of the winter. Tab 23 contains the historical results of the FPO program as required by Order No. 24,515 issued on September 16, 2005 in DG 05-127.

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 Tab 7, Schedule 7, Page 2, the Company has hedged a total of 2,240,000 Dekatherms (22.4 million therms) at a weighted average fixed price of $3.9706 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 23 contracts that hedge the price of gas supplies for the 2013/14 Winter Period with prices ranging from $3.516 to $4.460 per Dekatherm. The contracts date from May 11, 2012 through August 16, 2013. The contract dates, volumes and prices are listed in Exhibit 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 $0.0290 for the residential non-heating class and residential heating class, and $0.0357 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 2014 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 2013. 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 2012 that were filed with the Commission in DE 10-188 on May 31, 2013. The incentive calculations that are included in this LDAC filing are provided in Tab 19.

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

charge?

A. The proposed RLIAP charge is $0.0075. It is designed to recover administrative costs, revenue shortfall and the prior period reconciliation adjustment relating to this program. For the 2013/14 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 issued on September 22, 2006 in DG 06-120. The current RLIAP charge is designed to recover $1,207,706, of which $1,489,412 is for the revenue shortfall resulting from 5,435 customers receiving a 60% discount off their base rates, $ 8,600 is for estimated administrative costs, and ($290,305) is for the prior year reconciling adjustment.

Q. In Order No. 24,824 in docket 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 Tab 24 the short-term debt limit for fuel and non-fuel purposes for the 2013-14 period. As shown, the short term limit for fuel inventory financing for the period November 1, 2012 through October 31, 2013 is calculated to be $20,314,633 and the limit for non-fuel purposes is calculated to be $46,622,765.

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 Tab 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 Tab 20. The Summary included in Tab 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. While the recoveries are displayed on the summary by site, they are not exclusive to a particular site. Because the recoveries are often the result of general settlement agreements covering more than one site, there is no basis to determine how much of the settlement amount is associated with a particular site. Page 13 provides the total remediation and recovery costs and collections by year and in total.

In total, the Company has incurred environmental remediation costs of $34,518,979, litigation costs of $9,465,391, and obtained third party cash recoveries of $28,441,885, for a net expense of $15,542,485. To date, the Company has collected $13,487,314 from its Environmental Surcharge and base rates. Included in the remediation costs of $34,518,979 is a prior year's audit adjustment in the amount of $(1,876).

The 2012-2013 remediation costs that the Company is including in this filing are as follows:

Concord (Pool #14)	$78,387
Concord (Pool #10)	84,256
Laconia (Pool #12)	642,986
Manchester (Pool #13)	82,113
Nashua (Pool #13)	119,095
Keene (Pool#10)	1,400
General (Pool #11)	75,204
Total Remediation	1,083,441
Litigation Recovery	529,616
Litigation Costs	0
Total 2011-2012	$553,825

A summary sheet and detailed backup spreadsheets are provided in Tab 20 of this filing that support the 2012-2013 costs that the Company is submitting. Consistent with past practice, the Company met with the Commission staff earlier 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. The Company is prepared to provide additional testimony and exhibits, if necessary, to further support recovery of these amounts after the Commission Staff has completed its review of these costs.

Q. In 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 Schedules in Tab 20 to include the base rate recoveries for the period June 2010 through October 2013. 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 2013. The Company calculated the environmental rate that was embedded in the base rates 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. Finally, the Company allocated these environmental base rate revenues to those specific pools with outstanding balances.

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, 2013 and ending October 31, 2014 is $0.0018 per therm. This surcharge will recover a total of $363,892 in amortized remediation costs less the $78,892 in base rate collections for a net of $285,000. The costs submitted for recovery are presented in the Environmental Cost Summary included in Tab 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.

Q. Is the Company proposing to include any Temporary Rate Reconciliation Adjustment approved in Order 25,217 in DG 11-046 relating to the reconciliation for temporary rates from the Company's last base rate case, DG 10-017?

A. No, it is not. The Company projects that it will have an over collection of $20,372 once the current LDAC charge ends on October 31, 2013. The Company proposes determining how to return the final over collection after it has been finalized.

Q. Has the Company also updated its Company Allowance percentage for the period November 2013 through October 2014 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 November 2013 – October 2014. The Company calculated the Company Allowance of 1.3% based on sendout and throughput data for the twelve-month period ending June 2013. This recalculated Company Allowance is proposed to be applied to all supplier deliveries beginning in November 2013.

Q. Has the Company made any other changes to schedule 25?

A. Yes, it has. The Company has included its calculation of the unaccounted for gas percentage ("UFG%") for the twelve months ended June 30, 2013. The UFG% is 0.5%, which is below the 1.28% UFG cap set forth on page 21 of the Settlement Agreement in DG 11-040.

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 Tab 8, Schedule 8 of this filing. These bill impacts include the base distribution rates approved in Order No. 25,530 in Docket DG 13-149 relating to the cast iron/bare steel main replacement program. The total bill impact for an average residential heating customer is an increase of approximately $82, or 10.4%. The total bill impact for an average commercial/industrial G-41 customer is an increase of approximately $215, or 10.1%. Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

<u>OTHER TARIFF CHANGES</u>

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

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

Q. Please describe the changes to tariff Page 155.

A. In Proposed Second Revised Page 155, the Company is updating the Peaking Demand Charge from $18.62 per MMBtu of Peak MDQ to $18.53 per MMBtu of Peak MDQ, a $0.09 decrease and its Supplier Balancing Charges from $0.19 per MMBtu to $0.21 per MMBtu.

This calculation is also presented in Tab 21. It includes the four-page back up Calculations to III Delivery Terms and Conditions Proposed Second Revised Page 155, Attachment B – Peaking Demand Charge.

Q. Please describe the changes to tariff Page 156.

A. Proposed Second 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. Tab 22 contains the six-page worksheet that backs up the calculations for the updated allocators.

<u>OCCUPANT BILLING</u>

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

A. The Company started reviewing its existing Occupant Account billing policy, but has decided to defer any changes until after successful implementation of its customer billing system. The implementation of the new billing system is expected to occur in early September 2013.

Q. Does this conclude your testimony?

A. Yes, it does.