REDACTED

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 18-XXX

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Winter 2018/2019 Cost of Gas Filing
Summer 2019 Cost of Gas Filing

DIRECT TESTIMONY

OF

DAVID B. SIMEK

AND

CATHERINE A. MCNAMARA

August 31, 2018

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I. <u>INTRODUCTION</u>

Q. Please state your full name and business address.

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

(CM) My name is Catherine A. McNamara. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed.

A. We are employed by Liberty Utilities Service Corp. ("Liberty"), which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

Q. Please describe your educational background and your business and professional experience.

A. (DS) 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. In August 2013, I joined Liberty as a Utility Analyst and I was promoted to Manager, Rates and Regulatory Affairs in August 2017. Prior to my employment at Liberty, 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.

(CM) I graduated from the University of Massachusetts, Boston, in 1993 with a Bachelor of Science in Management with a concentration in Accounting. In November 2017, I joined Liberty as an Analyst in Rates and Regulatory Affairs. Prior to my employment at Liberty, I was employed by Eversource as a Senior Analyst in the Investment Planning group from 2015 to 2017. From 2008 to 2015, I was a Supervisor in the Plant Accounting department. Prior to my position in Plant Accounting, I was a Financial Analyst/General Ledger System Administrator within the Accounting group from 2000 to 2008.

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

A. (DS) Yes. I have testified on numerous occasions before the Commission.

(CM) Yes, I previously testified in EnergyNorth's Cast Iron/Bare Steel Replacement Program proceeding, Docket No. DG 18-064.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain the Company's proposed firm sales cost of gas rates for the 2018/19 Winter (Peak) Period and the Company's proposed 2018/19 Local Delivery Adjustment Clause, both effective November 1, 2018. Our testimony also explains the Company's proposed firm sales cost of gas rates for the 2019 Summer (Off-Peak) Period.

II. WINTER 2018/19 COST OF GAS FACTOR

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

A. The Company proposes a firm sales cost of gas rate of $0.7411 per therm for residential customers, $0.7403 per therm for commercial/industrial high winter use customers, and $0.7456 per therm for commercial/industrial low winter use customers as shown on Proposed First Revised Page 92 (Bates 050). The Company proposes a firm transportation cost of gas rate of $0.0005 per therm as shown on Proposed First Revised Page 94 (Bates 052).

Q. Please explain tariff page Proposed Original Page 92.1 (Bates 051) and Proposed First Revised Page 92.

A. Proposed Original Page 92.1 and Proposed First Revised Page 92 contain the calculation of the 2018/19 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 92, the proposed 2018/19 Average Cost of Gas of $0.7411 per therm is derived by adding the Direct Cost of Gas Rate of $0.7056 per therm to the Indirect Cost of Gas Rate of $0.0355 per therm. The estimated total Anticipated Direct Cost of Gas, derived on Page 92.1 and repeated on Page 92, is $61,003,856. The estimated Indirect Cost of Gas, also derived on Page 92.1 and repeated on Page 92, is $3,070,244. The Direct Cost of Gas Rate of $0.7056 and the Indirect Cost of Gas Rate of $0.0355 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 86,451,254 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 92.1, total $656,690. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $60,347,166 to determine the Total Anticipated Direct Cost of Gas of $61,003,856.

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

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Original Page 92.1 consists of the following components:

1.	Purchased Gas Demand Costs	$10,308,483
2.	Purchased Gas Commodity Costs	41,318,346
3.	Storage Demand and Capacity Costs	922,462
4.	Storage Commodity Costs	5,125,663
5.	Produced Gas Cost	2,672,211
	Total	$60,347,166*

*$1 difference 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 Original Page 92.1, are as follows:

1.	Deferred Gas Cost Prior Period Under Collection	$2,599,354
2.	Interest	63,196

3.	Fuel Inventory Revenue Requirement	351,017
4.	Broker Revenues	(497,759)
5.	Transportation COG Revenue	(26,381)
6.	Capacity Release Margin	(1,877,737)
7.	Fixed Price Administrative Cost	45,000
	Total Adjustments	$656,690

These allowable adjustments are standard adjustments made to the deferred gas cost balance through the operation of the Company's cost of gas adjustment clause. We 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 Docket No. DG 17-135 for the 2017/18 Winter Period?

A. The average cost of gas rate proposed in this filing of $0.7411 per therm is $0.0966 per therm more than the initial rate of $0.6445[1] per therm approved by the Commission in Order No. 26,066 (October 31, 2017) in Docket No. DG 17-135. The $0.0966 per therm increase in the rate reflects a $2,530,984 increase in the Total Unadjusted Cost of Gas.

Q. How does the proposed firm transportation winter cost of gas rate compare to the rate approved by the Commission for the 2017/18 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0005 per therm. The rate approved in Docket No. DG 17-135 was $0.0027 per therm. The decrease in the rate relates to an estimated $88,304 decrease in costs due to the difference between the winter

1 For comparison purposes, by the end of the 2017/18 Winter Period, the residential cost of gas rate increased to $0.8056 per therm through the operation of the monthly adjustment mechanism.

season 2017/2018 beginning balance of $28,808 (an over-collection) and the winter season 2018/2019 beginning balance of ($59,496) (an under-collection).

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. Yes. The Company used, for pressure support purposes, a rate of 8.7% based on the marginal cost study used for the rate design approved in Docket No. DG 17-048. Previously the Company used an estimated percentage of 9.9% for pressure support purposes.

Q. Did the Company include a fuel inventory revenue requirement calculation in this filing?

A. Yes (Bates 192). The Company is proposing to collect $351,017 in fuel inventory revenue requirement consistent with Order No. 26,156 dated July 10, 2018, in Docket No. DG 17-048. The rate of $0.0041 per therm is determined by dividing the $351,017 by the estimated November 2018 through October 2019 COG sales volumes of 86,451,254 therms.

Q. How was the statutory tax rate of 27.24% calculated (Bates 192)?

A. The statutory rate of 27.24% was calculated by using a 21% federal tax rate and a 7.9% tax rate for the State of New Hampshire (0.21 + 0.079 – (0.21 x 0.079) = 0.2724).

Q. How was the common equity pre-tax rate of 6.290% calculated (Bates 192)?

A. The common equity pre-tax rate of 6.290% was calculated by dividing the 9.30% rate of return on common equity, approved in Docket No. DG 17-048, by 0.7276 (1 – 0.2724 [statutory tax rate – see previous question]) and multiplied by 49.20% (equity component of the capital structure approved in DG 17-048) [0.930 / 0.7276 x 0.4920 = 0.0629].

Q. Has the bad debt percentage in this filing of 1.7% changed from the bad debt percentage calculated in the Winter 2017/2018 Cost of Gas Reconciliation?

A. Yes, the bad debt percentage of 1.7% used in this filing is the calculated rate for the period of May 2017–April 2018. The Winter 2017/2018 Cost of Gas Reconciliation included a calculated rate of 1.1%, which was inadvertently carried forward from the prior period of May 2016–April 2017.

Q. What was the actual weighted average firm sales cost of gas rate for the 2017/18 winter period?

A. The weighted average cost of gas rate was $0.7321 per therm (Bates 095 Line 54). This was calculated by applying the actual monthly cost of gas rates for November 2017 through April 2018 to the monthly therm usage of an average residential heating customer using 778 therms per year, or 636 therms for the six winter period months.

III. <u>PRIOR WINTER PERIOD UNDER-COLLECTION</u>

Q. Please explain the prior period under collection of $2,459,330.

A. The prior period under-collection is also detailed in the 2017/18 Winter Period Reconciliation that was filed with the Commission on July 27, 2018. The $2,459,330 under-collection is the sum of the deferred gas cost, bad debt, and working capital over- and under-collection balances as of April 30, 2018. The under-collection was driven mainly by the lag in the timing of monthly cost of gas rate adjustments as compared to changes in the underlying costs. For three months within the six-month winter period the calculated COG rate adjustment was higher than the allowable 25% price increase so the Company held the rate constant at the maximum allowable rate of $0.8056 per therm.

IV. 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. Proposed First Revised Page 91 (Bates 049) contains the FPO rate for the 2018/19 Winter period, which is $0.7611 per therm for residential customers. This compares to the FPO rate approved for the 2017/18 winter period of $0.6645 per therm for residential customers. This represents a $0.0966 per therm, or 14.5% increase in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 636 therms is an increase of approximately $122.86 or 14.25% compared to last winter. The total bill impact reflects the implementation of the increases approved in Docket Nos. DG 17-048 effective May 1, 2018, and DG 18-064 effective July 1, 2018, relating to permanent distribution rates and the cast iron/bare steel main replacement program, respectively. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $12.71 (or 1.3%) 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 (Bates 189) contains the historical results of the FPO program.

V. LOCAL DELIVERY ADJUSTMENT CLAUSE ("LDAC")

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

A. As shown on Proposed First Revised Page 97 (Bates 055), the Company is submitting for approval an LDAC of $0.0836 per therm for the residential non-heating class and residential heating class, and $0.0772 per therm for the commercial/industrial bundled sales classes, effective November 1, 2018. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Clause, the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Low Income Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 17-048.

Q. Which customers are billed an LDAC?

A. All EnergyNorth customers including those in Keene are billed an LDAC charge. When calculating the LDAC charge, the November 1, 2018, through October 31, 2019, forecasted Keene therm sales of 1,451,361 are added to the EnergyNorth therm sales forecast of 183,203,513 for a total therm sales forecast of 184,654,874.

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 2019 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 2018. As shown on Schedule 19 Energy Efficiency (Bates 125-127), the proposed Energy Efficiency charge is $0.0450 per therm for Residential customers and $0.0387 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Clause ("RDAC").

A. The first RDAC will not take effect until November 1, 2019, after the first decoupling year is complete. It is designed to recover, on an annual basis, the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer. The Actual Base Revenue per Customer is calculated after the first decoupling year. Schedule 19 RDAC (Bates 122) shows the proposed Benchmark Base Revenue per Customer calculation effective November 1, 2018, through October 31, 2019.

Q. Please explain the Energy Efficiency Resource Standard Lost Revenue Adjustment Mechanism ("LRAM").

A. As shown on Schedule 19 LRAM (Bates 120-121), the proposed LRAM charge is $0.0003 per therm for residential customers and $0.0001 per therm for commercial and industrial customers. It is designed to recover lost revenues associated with energy efficiency measures installed under the EERS programs. Since the Company is implementing decoupling effective November 1, 2018, the Company will continue to implement its Lost Revenue Adjustment only as a prior period true-up mechanism effective November 1, 2018, and ending October 31, 2019.

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

A. As shown on Schedule 19 RLIAP (Bates 123-124), the proposed RLIAP charge is $0.0130 per therm. It is designed to recover administrative costs, revenue shortfall, and the prior period reconciliation adjustment relating to this program. For the 2018/19 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 (Sept. 22, 2006) in Docket No. DG 06-120. The current RLIAP charge is designed to recover $2,409,164, of which $1,864,087 is for the revenue shortfall resulting from 5,056 customers receiving a 60% discount off their base rates, and $545,077 for the prior year reconciling adjustment.

Q. In Order No. 24,824 (Feb. 29, 2008) 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 (Bates 190) the short-term debt limit for fuel and non-fuel purposes for the 2018/19 period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2018, through October 31, 2019, is calculated to be $19,222,230 and the limit for non-fuel purposes is calculated to be $94,878,262.

Q. Has the Company updated the Environmental Surcharge (Tariff Page 95)?

A. Yes, it has. The costs submitted for recovery through the MGP remediation cost recovery mechanism, as well as the third party recoveries, are included in the Environmental Cost Summary in Schedule 20 (Bates 128) 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 direct 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 shows the remediation cost pools for the Concord Pond, Concord MGP, Manchester, Nashua, and Laconia sites, and a General Pool for costs that cannot be directly assigned to a specific site.

A summary sheet and detailed backup spreadsheets that support the 2017/18 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 provide an update on the status of environmental matters. Ms. Casey's testimony describes the Company's activities with regard to all five sites.

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, 2018, and ending October 31, 2019, is $0.0161 per therm. This surcharge will recover a total of $2,970,867 in amortized remediation costs. The costs submitted for recovery are shown in the Environmental Cost Summary included in Schedule 20 of this filing.

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

A. Yes. As shown on Schedule 19 RCE (Bates 118-119), the Company is proposing to collect $1,706,158 in uncollected rate case and recoupment expense consistent with Order No. 26,122 dated April 27, 2018, in Docket No. DG 17-048. The RCE rate of $0.0092 per therm is determined by dividing the $1,706,154 by the estimated November 2018 through October 2019 sales volumes of 184,654,874 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2018 through October 2019 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 191) the Company has recalculated its Company Allowance for the period November 2018 through October 2019. The Company calculated the Company Allowance of 1.80% based on sendout and throughput data for the twelvemonth period ending June 2018. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2018.

VI. CUSTOMER BILL IMPACTS

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

A. The bill impact analysis is presented in Schedule 8 (Bates 095) of this filing. These bill impacts reflect the implementation of the increases approved in Docket Nos. DG 17-048 effective May 1, 2018, and DG 18-064 effective July 1, 2018, relating to permanent distribution rate increases and 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 $67.17, or 7.42%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is an increase of approximately $86.13, or 3.38% (Bates 096). Schedule 8 of this filing provides more detail of the impact of the proposed rate adjustments on heating customers.

VII. OTHER TARIFF CHANGES

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

A. Yes. The Company is submitting Proposed First Revised Page 147 (Bates 056) relating to Supplier Balancing and Peaking Demand Charges and Proposed First Revised Page 148 (Bates 057) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 147.

A. In Proposed First Revised Page 147, the Company is updating the Peaking Demand Charge from $20.06 per MMBtu of Peak MDQ to $20.41 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 180).

Q. Please describe the changes to tariff Page 148.

A. Proposed First Revised Page 148 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 (Bates 183-188) contains the six-page worksheet that backs up the calculations for the updated allocators.

VIII. SUMMER 2019 COST OF GAS FACTOR

Q. What are the proposed 2019 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.4445 per therm for residential customers, $0.4417 per therm for commercial/industrial high winter use customers, and $0.4506 per therm for commercial/industrial low winter use customers as shown on Proposed Seventh Revised Page 89 (Bates 200).

Q. Please explain tariff pages Proposed First Revised Page 88 and Proposed Seventh Revised Page 89.

A. Proposed First Revised Page 88 (Bates 199) and Proposed Seventh Revised Page 89 contain the calculation of the 2019 Summer Period Cost of Gas Rate and summarize the Company’s forecast of firm gas sales, firm gas sendout, and gas costs. On Proposed

Seventh Revised Page 89, the 2019 Average Cost of Gas of $0.4445 per therm is derived by adding the Direct Cost of Gas Rate of $0.4354 per therm to the Indirect Cost of Gas Rate of $0.0091 per therm. The estimated total Anticipated Direct Cost of gas is $8,661,183 and the estimated Indirect Cost of Gas is $181,903. The Direct Cost of Gas Rate and the Indirect Cost of Gas Rates are determined by dividing each of these total cost figures by the projected Summer firm sales volumes of 19,890,267 therms. Proposed Seventh Revised Page 89 further shows that the Residential Cost of Gas Rate of $0.4445 per therm is equal to the Average Cost of Gas for all firm sales customers. It also shows the calculation of the Commercial/Industrial High Winter Use Cost of Gas Rate of $0.4417 per therm and the Commercial/Industrial Low Winter Use Cost of Gas Rate of $0.4506 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed First Revised Page 88. To derive the total Anticipated Direct Cost of Gas of $8,661,183, the Company starts with the Unadjusted Anticipated Cost of Gas of $8,002,703 and adds the Net Adjustment totaling $658,480.

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

A. The Unadjusted Anticipated Cost of Gas consists of the following:

1. Purchased Gas Demand Costs	$4,372,669
2. Purchased Gas Supply Costs	3,602,943
3. Produced Gas Costs	27,091
Total Unadjusted Anticipated Cost of Gas	$8,002,703

Q. What are the components of the adjustments to the cost of gas?

A. The adjustments to gas costs, listed on proposed First Revised Page 88, are as follows:

1. Prior Period (Over)/Under Collection	$617,043
2. Interest	41,437
Total Adjustments	$658,480

Q. How does the proposed average Residential Summer cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2018 Summer Period?

A. The cost of gas rate proposed in this filing is $0.1312 per therm higher than the initial rate approved by the Commission for the 2018 Summer Period ($0.4445 vs. $0.3133) (Schedule 8, Bates 224). This increase is primarily due to an $874 thousand anticipated increase to the Supply Costs.

Q. Does this conclude your testimony?

A. Yes, it does.

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